BC Hydro
Power smart

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February 25, 2019

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (the Application)

BC Hydro writes to file the Application requesting various approvals from the BCUC for fiscal 2020 and fiscal 2021.

If approved, these requests would result in a net bill increase of 1.76 per cent on April 1, 2019 and 0.72 per cent on April 1, 2020.

We request that these changes be made effective April 1, 2019, on an interim basis, pending a final BCUC decision on the Application.

For further information, please contact Chris Sandve at 604-974-4641 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

cs/af

Enclosure

Copy to: BCUC Project No. 3698869 (BC Hydro F2017 to F2019 Revenue Requirements Application) Registered Intervener Distribution List.

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Chapter 1

Executive Summary

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1.1 Introduction

British Columbia Hydro and Power Authority (**BC Hydro**) is a Crown corporation established under the *Hydro and Power Authority Act* and regulated by the British Columbia Utilities Commission (**BCUC**) under the *Utilities Commission Act*. Our owner and sole shareholder is the Government of B.C.

We provide electricity to 95 per cent of British Columbia's population in a service area that encompasses most of the province. We have approximately 2.0 million customer accounts and provide service to approximately 4.0 million people and businesses. Our system includes 30 hydroelectric generating facilities, two natural gas-fired generating facilities, 134 contracts with Independent Power Producers (**IPPs**) and approximately 86,000 kilometers of transmission and distribution lines.

BC Hydro files this Revenue Requirements Application (**Application**) to request various approvals from the BCUC for fiscal 2020 and fiscal 2021 (**test period**). Our requests are summarized in section 1.6 of this chapter. If approved, these requests would result in a net bill increase of 1.76 per cent on April 1, 2019 and 0.72 per cent on April 1, 2020.

These net bill increases reflect the proposed reduction of the Deferral Account Rate Rider (**DARR**) from 5 per cent to 0 per cent on April 1, 2019 and permanent general rate increases of 6.85 per cent on April 1, 2019 (for fiscal 2020) and 0.72 per cent on April 1, 2020 (for fiscal 2021).[1]

[1] Offsetting the requested general rate increase of 6.85 per cent with the requested reduction of the DARR from 5 per cent to 0 per cent reduces the net bill increase by more than 5 per cent because the DARR is applied after general rate increases. The following equation demonstrates how this works:

Start: Bill with 5 per cent DARR: $105.00.

Adjust: DARR from 5 per cent to 0 per cent: $100.00.

Adjust: General Rate Increase of 6.85 per cent: $106.85.

$106.85/$105.00 = 1.0176.

This Chapter is organized around the following key points:

- Section 1.2 explains that this application reflects careful planning and prioritization to invest in safe and reliable electricity service while keeping rate increases as low as possible.
- Section 1.3 sets out our Plan-Build-Operate-Support organizational model, which encourages consistent adoption of best practices used across the company and facilitates stronger collaboration and cooperation in similar functions across our business.
- Section 1.4 explains that Phase One of the Government of B.C.'s Comprehensive Review of BC Hydro (**Comprehensive Review**) has resulted in changes that have enhanced the BCUC's oversight of BC Hydro and reduced the forecast increase in BC Hydro's electricity rates.
- Section 1.5 identifies how we have considered and acted upon recent BCUC directives and recommendations in drafting this application.
- Section 1.6 sets out the specific approvals that we are seeking in this application.
- Section 1.7 summarizes our forecast revenue requirements, which total $5,256.5 million for fiscal 2020 and $5,288.3 million for fiscal 2021.
- Section 1.8 provides an overview of why our forecast revenue requirements in the test period represent reasonable costs to provide safe and reliable electricity.
- Section 1.9 summarizes external studies and independent expertise which demonstrate that our costs are reasonable and that our operations are well managed.
- Section 1.10 provides a proposed regulatory process for the BCUC and interveners to review this application. The proposed process reflects our belief that an open and transparent relationship with the BCUC and interveners in

regulatory proceedings leads to better decisions and improved outcomes for our customers.

1.2 Safely Providing Reliable, Affordable, Clean Electricity

BC Hydro's mission is to safely provide reliable, affordable, clean electricity throughout British Columbia. We have a responsibility to our customers to address cost pressures while keeping rate increases as low as possible. Accordingly, this application reflects careful planning and prioritization.

1.2.1 BC Hydro is Meeting Service Plan Performance Measures

Each year, BC Hydro prepares an annual Service Plan. The Service Plan sets out four goals which align with our mission. Each goal has a set of performance measures which represent the commitments we make to our customers. In fiscal 2018, we successfully met or exceeded all 13 of our Service Plan performance measures and for fiscal 2019, we are on track to meet all of our performance measures, with the exception of our target for Lost Time Injury Frequency. Our fiscal 2020 to fiscal 2022 Service Plan is provided as Appendix E.

1.2.2 Affordability is Important

One of the performance measures in our Service Plan is Affordable Bills. BC Hydro participates in an annual survey by Hydro Quebec of electricity costs in 22 cities in Canada and the United States. Our goal is to be in the first (i.e., best) quartile of utilities surveyed for residential rates. For 2018, BC Hydro's average residential bills were the third lowest and within the first quartile. Based on power consumption, small power bills were between fifth and eighth lowest; medium power bills were between third and fourth lowest and large power bills were between third and fifth lowest. BC Hydro's 2018 Electricity Rate Comparison Report is provided as Appendix V.

While the Hydro Quebec survey provides an important benchmark of BC Hydro's performance, we are conscious of the impact that any bill increase may have on our customers. Many of our residential customers face affordability challenges and many of our commercial and industrial customers face challenging market conditions.

1.2.3 BC Hydro Faces Significant Cost Pressures

Many factors continue to put upward pressure on BC Hydro's costs, which drives the amount we must charge customers for electricity. Notable factors putting upward pressure on our costs and rates include:

- **Load forecast**: Our Load Forecast expects a more moderate increase in the demand for electricity relative to the load forecast provided in our Fiscal 2017-Fiscal 2019 Revenue Requirements Application (**Previous Application**). This means less revenue is available to fund operations and investments. Further information is provided throughout Chapter 3.
- **Cost of Energy**: Our forecast costs of energy are increasing, primarily because of cost increases on existing IPP contract. Further information is provided throughout Chapter 4.
- **Operating costs**: We face significant uncontrollable operating cost increases, such as increased storm restoration costs, which reflect the higher levels of storm related damage experienced in recent years. Further information is provided throughout Chapter 5.
- **Capital investments**: Ongoing investments are required to maintain, upgrade and expand our electricity system. Further information is provided throughout Chapter 6.
- **Recovering account balances**: While BC Hydro's overall regulatory account balances are forecast to be reduced from approximately $5.4 billion at the end of fiscal 2018 to $3.6 billion at the end of fiscal 2019, the remaining balance must continue to be recovered from customers. Further information is provided throughout Chapter 7.

1.2.4 Planning and Prioritization is Required to Achieve the Right Balance Between Investment and Low Rates

BC Hydro's forecast revenue requirements are the product of careful planning and prioritization. They reflect what we believe is an appropriate level of spending in fiscal 2020 and fiscal 2021 to safely provide reliable and clean electricity, while keeping rate increases as low as possible. Examples of our planning and prioritization appear throughout this application, and include the following:

- **Cost of energy mitigation:** In Chapter 4, we identify actions taken to reduce our forecast costs of energy. BC Hydro is not acquiring new resources from IPPs, with the exception of a small number of new First Nations energy projects and some EPA renewals, such as new contracts under the Biomass Energy Program. In addition, BC Hydro and the Government of B.C. have taken steps since fiscal 2015 to reduce IPP power acquisitions. These steps include the indefinite suspension of the Standing Offer Program (**SOP**), terminating three EPAs, and not renewing three other EPAs that expired.
- **Reduction in controllable operating costs:** In Chapter 5, we explain that BC Hydro is limiting base operating cost increases[2] below the forecast rate of inflation,[3] by offsetting non-controllable cost increases with reductions to controllable costs. BC Hydro has achieved reductions in controllable costs through a variety of means, including vacancy factor savings, lease consolidations, and a reduction to advertising costs.
- **Moderating capital investment:** In Chapter 6, we explain how information on system performance has informed decisions to moderate our level of capital investment.

[2] BC Hydro explains in Chapter 5, section 5.5.1 why base operating costs should be the focus.
[3] BC Hydro uses the B.C. Consumer Price Index measure for the forecast rate of inflation. The forecast rate of inflation for fiscal 2019, fiscal 2020 and fiscal 2021 is 2.7 per cent, 2.3 per cent and 2.0 per cent, respectively.

- **Managing DSM spending:** In Chapter 10, we set out our proposed demand side management (**DSM**) expenditure schedule. It provides broad customer access to conservation and energy management opportunities, while managing the overall level of expenditures to limit forecast rate increases.

1.3 The Move to a Centralized and Functionally Aligned Organization is Complete

In October 2017, BC Hydro took the last step in moving to a centralized and functionally-aligned organizational structure. This final, incremental change completes the shift towards centralizing functions that BC Hydro has pursued over time. This functional alignment encourages consistent adoption of best practices used across the company and facilitates stronger collaboration and cooperation in similar functions across our business.

In recent years, BC Hydro had centralized its Finance, Safety and Supply Chain functions. The most significant part of the recently completed final step was to:

- Bring together the Key Business Units (**KBU**) responsible for power system planning into a Business Group called Integrated Planning; and
- Bring together the KBUs responsible for power system operations into a Business Group called Operations.

This final step was not intended to drive specific cost reductions, but we believe that the intangible benefits of improved collaboration and consistent adoption of best practices can only assist the efficient management of the company. Our Safety Business Group provides a good illustration of the benefits of functional alignment. Safety functions were previously distributed throughout the business. In its Decision on BC Hydro’s Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, the BCUC encouraged BC Hydro to implement a comprehensive safety management program.[4] Since centralizing, we have been able to improve consistency of and clarity on safety requirements throughout the company. This promotes improved safety performance and a stronger safety culture.[5]

The centralized organizational structure aligns our Business Groups to the lifecycle of our work delivery. Our Business Groups are now organized under our four major work functions – Plan, Build, Operate, and Support. This is shown in Figure 1-1 below.

Figure 1-1 Plan-Build-Operate-Support Model

The change brings together groups with similar functions that were previously separated by our different lines of business - Generation, Transmission, and Distribution. In addition, KBUs within these Business Groups have aligned their work to our main asset types – station assets (generation plants and substations) and line assets (transmission and distribution lines).

A more detailed explanation of our Plan-Build-Operate-Support model is provided in Chapter 5, section 5.3.2.

4 British Columbia Utilities BCUC Decision and Order No. G-16-09, BC Hydro F2009 and F2010 Revenue Requirements Application (March 13, 2009), page 49.

5 BC Hydro 2017/18 Annual Service Plan Report, Pages 18-20, 'Goal 4: Safety Above All, Safety Performance Measures.

1.4 The Comprehensive Review of BC Hydro Has Enhanced BCUC Oversight and Reduced Forecast Rate Increases

On February 14, 2019, the Government of B.C. released a report on Phase One of the Comprehensive Review, which is included as Appendix C.

The review resulted in changes that have enhanced the BCUC's oversight of BC Hydro and reduced the forecast increase in BC Hydro's electricity rates.

1.4.1 BCUC Oversight Has Been Enhanced

To enhance the regulatory oversight of BC Hydro while still advancing its social, economic and environmental priorities, the Government of B.C. has:

- Accepted a recommendation for BC Hydro to cease using the Rate Smoothing Regulatory Account, and to write-off the balance in the account in fiscal 2019;
- Repealed a number of regulations that had restricted the BCUC's decision making in the past. Moving forward, this will enable the BCUC to review and make decisions on BC Hydro's costs, proposed rate increases and almost all regulatory accounts, programs and capital projects;
- Announced its intent to introduce legislation in spring 2019 to restore the BCUC's authority to review and approve BC Hydro's Integrated Resource Plan (**IRP**);
- Enabled the BCUC to begin setting BC Hydro's allowed net income for rate-setting purposes, following a two-year transition period for fiscal 2020 and fiscal 2021, during which BC Hydro's current net income target of $712 million will remain in place; and
- Changed the accounting rules that BC Hydro is required to follow so that BC Hydro will fully adopt International Financial Reporting Standards (**IFRS**) for fiscal 2019.

Further information on these changes is provided in Chapter 2, section 2.2.

1.4.2 Actions by BC Hydro and Government to Keep Rates Affordable

Phase One of the Comprehensive Review also includes a number of actions by the Government of B.C. and BC Hydro to keep rates affordable.

As a result of these actions, the cumulative increase in bills for ratepayers is forecast to be 8.1 per cent over the next five years (April 1, 2019 to March 31, 2024). This is approximately 40 per cent lower than the 13.7 per cent increase for the same period under the 2013 10 Year Rates Plan and more than 20 per cent lower than the forecast rate of B.C. inflation for the period. This is shown in Figure 1-2 below.

Figure 1-2 Bill Impact Forecast (Fiscal 2020 to Fiscal 2024)

	Fiscal 2020 Apr 1, 2019 – Mar 31, 2020	Fiscal 2021 Apr 1, 2020 – Mar 31, 2021	Fiscal 2022 Apr 1, 2021 – Mar 31, 2022	Fiscal 2023 Apr 1, 2022 – Mar 31, 2023	Fiscal 2024 Apr 1, 2023 – Mar 31, 2024	Cumulative Five Years
Current Rates Forecast – Annual Rate Increase before reducing the DARR	6.8%	0.7%	2.2%	0.0%	3.2%	n/a
Current Rates Forecast – Annual Bill Impact including reduction in DARR*	1.8%	0.7%	2.2%	0.0%	3.2%	8.1%
Previous Govt's 10 Year Rates Plan – Annual Bill Impact	2.6%	2.6%	2.6%	2.6%	2.6%	13.7%
Forecast BC Inflation	2.3%	2.0%	2.0%	2.0%	2.0%	10.7%

The following provides a summary of the actions that the Government of B.C. and BC Hydro are taking to keep rates affordable. These actions are reflected in the requests BC Hydro is seeking in this application.

- **Writing off $1.1 billion deferral account balance:** The write-off of the Rate Smoothing Regulatory Account contributes to a reduction in BC Hydro's forecast overall regulatory account balance at the end of fiscal 2019 by 24 per cent, from $4.7 billion to $3.6 billion. Lowering the overall regulatory account balance means lowering the amount that would otherwise be recovered from ratepayers, reducing pressure on rates. Further information is provided in Chapter 7, section 7.7.6.

- **Suspending the SOP**: The SOP has been indefinitely suspended, in accordance with Regulation 23/2019, issued under the *Clean Energy Act*. Further information is provided in Chapter 4, section 4.3.2.
- **Lower biomass costs:** Through a new Biomass Energy Program, BC Hydro will acquire up to 80 per cent, in aggregate, of the historical energy deliveries received under biomass EPAs that are due to expire before March 31, 2022. The prices offered for biomass energy will be lower relative to current contract terms to achieve savings for ratepayers. Further information is provided in Chapter 4, section 4.3.2.
- **Reduced capital investments:** BC Hydro has reduced planned capital expenditures and additions. A more moderate rate of load growth than previously anticipated means that the timing of some planned investments to expand BC Hydro's system have changed. A consistently high level of historic system performance has provided an opportunity to moderate the level of sustainment investments, compared to previously planned amounts. Further information is provided in Chapter 6, section 6.3.
- **Base operating cost increases below inflation:** Despite significant cost pressures, BC Hydro is limiting base operating cost increases below the forecast rate of inflation over the test period. Further information is provided in Chapter 5, section 5.5.2.

1.5 BC Hydro Has Considered and Acted Upon the BCUC's Directions and Recommendations

While drafting this application, we considered recent BCUC directives, recommendations and observations, including those from the BCUC's March 1, 2018 Decision on our Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (**Decision**). The following sections indicate how this application reflects the BCUC's comments.

1.5.1 Actual Load Has Tracked Close to Forecast

In its Decision, the BCUC noted that the domestic revenue variance,[6] which captures the difference between actual and forecast load, has been consistently negative and growing since fiscal 2009.[7]

The load forecast variance which is the difference between actual and approved domestic energy sales volumes,[8] is shown in Table 1-1 below. Actual results have tracked within 0.05 per cent to 0.5 per cent against the May 2016 Load Forecast from the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (Previous Application), which is well within a range of expectancy based on industry benchmarks.

Table 1-1 Actual and Approved Domestic Energy Sales Volumes

	Approved (GWh)	Actual (GWh)	Variance (GWh)	Variance (%)
Fiscal 2017	51,550	51,577	27	0.05
Fiscal 2018	51,528	51,789	261	0.51

6 The domestic revenue variance deferred to the Non-Heritage Deferral Account is equal to the difference between the RRA forecast domestic revenue sub-total and the Actual domestic revenue sub-total (refer to Appendix A, Schedule 14.0, line 20), adjusted to remove revenues related to Seattle City Light (refer to Appendix A, Schedule 14.0, line 18). This is because variances related to Seattle City Light are deferred to the Heritage Deferral Account.

7 BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), Appendix B, page 10.

8 Excluding sales to Seattle City Light.

The difference between actual and approved domestic energy sales revenues[9] is shown in Table 1-2 below. Actual results have tracked within -0.03 per cent and 0.29 percent of planned amounts.

Table 1-2 Actual and Approved Domestic Energy Sales Revenues

	Approved ($ million)	Actual ($ million)	Variance ($ millions)	Variance (%)
Fiscal 2017	4,474.3	4,473.0	(1.3)	-0.03
Fiscal 2018	4636.9	4650.4	13.5	0.29

1.5.2 We Considered an Alternative Short-Term Load Forecast Methodology

In its Decision, the BCUC noted that some utilities use a different load forecast methodology for their short-term forecast for setting rates as compared to their long-term forecast for resource planning.[10]

In light of the BCUC's observation, we reviewed other utilities' short-term forecast methodologies. We developed an alternative forecast based on the methodology used by FortisBC Inc., the other major electric utility in B.C.

Results of our alternative forecast comparison showed BC Hydro averaged a billed sales variance of -0.3 per cent (residential sector) and -0.4 per cent (commercial sector) for fiscal 2016 to fiscal 2018, using our load forecasting methodology, while the average billed sales variance using FortisBC Electric's methodology was 2.4 per cent (residential sector) and 0.8 per cent (commercial sector) for the same time period.

Considering the recent performance of our own methodology, the results of our comparison using an alternative short-term forecast methodology, and recent improvements made to our methodology, we concluded that it was appropriate to

9 Excluding sales to Seattle City Light.

10 BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), Appendix B, page 11.

use our forecast methodology for this Load Forecast. Further information is provided in Chapter 3, section 3.2.11.

1.5.3 Price Elasticity Inputs Have Been Updated to Reflect Independent Expert Advice

In its Decision, the BCUC acknowledged the concerns of the Association of Major Power Consumers (**AMPC**) regarding the price elasticity used for industrial customers.[11] Utilities use price elasticity to help determine whether and to what extent customers may reduce their electricity demand in response to a price increase.

In March 2018, BC Hydro retained DNV GL to conduct an electricity price elasticity study for each of our customer sectors. DNV GL is a global quality assurance and risk management company, with a highly regarded energy advisory services division offering institutional, legal and technical expertise on electricity systems. The company has global operations in over 100 countries. The results of their price elasticity study are included as Appendix Q.

The DNV DL study results, combined with the results of our own evaluation of the residential inclining block rate (fiscal 2013 to fiscal 2017), supports the results of our previous internal studies and third party assessments that our price elasticity estimates are consistent with what is commonly reported and on the lower end of the survey data.

DNV GL’s key findings were adopted in the Load Forecast prepared for this application. Specifically, BC Hydro has increased the electricity price elasticity value used for all of the main customer sectors from -0.05 to -0.10. Further information is provided in Chapter 3, section 3.2.6.2.

[11] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), Appendix B, page 6.

1.5.4 We Improved the Industrial Load Forecast Inputs and Methodology

In its Decision, the BCUC noted that there are challenges in forecasting large industrial loads.[12] Load forecasting, especially with regards to the Industrial sector, is inherently uncertain. However, in response to the Decision and as part of our continuous improvement efforts, we have made changes to our load forecast methodology. Further information is provided in Chapter 3, section 3.2.6.2 (Residential), section 3.2.7.2 (Commercial and Light Industrial) and section 3.2.8.2 (Large Industrial).

1.5.5 LNG Sector Load is Now Forecast Consistent with Large Industrial Methodology

In its Decision, the BCUC noted that BC Hydro had forecast liquefied natural gas (**LNG**) plant loads based on public information announced by LNG proponents and for which BC Hydro has received interconnection service requests.[13] In this application, we have instead forecast sales to LNG customers in the same way that sales to all other customers in the large industrial sector are forecast. We believe that this approach will improve the performance of the Load Forecast by incorporating a probabilistic assessment of LNG customers. Further information is provided in Chapter 3, section 3.2.8.2.

1.5.6 We Are Optimizing the Value from Heritage Assets

In its Decision, the BCUC expressed concern that Heritage Assets may not be providing optimal value to BC Hydro customers.[14] BC Hydro is optimizing the use of heritage assets through our approach to both operations and capital investment.

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[12] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), Appendix B, page 11.

[13] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), Appendix B, page 7.

[14] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 24.

- Our monthly Energy Studies optimize our operational management of all sources of energy supply on BC Hydro's integrated system.
- Our capital planning process seeks to optimize our investment strategy for generation resources by categorizing our heritage assets as "Key", "Strategic" or "Available", according to the significance of the facility to BC Hydro's system. BC Hydro's Generation Strategic Asset Management Plan sets out a 10- year strategy for each category.

Further information is provided in Chapter 4, section 4.3.1.

1.5.7 Independent Experts Confirmed Our Energy Studies Methodology is Consistent with Leading Industry Practices

In its Decision, the BCUC recommended that BC Hydro review its approach to optimizing its portfolio of energy resources in its next IRP.[15] In fiscal 2019, BC Hydro undertook an internal audit of our monthly Energy Studies process. To complete this internal audit, two subject matter experts were engaged from SINTEF, an independent research organization that conducts contract research and development projects. These experts specialized in load forecasting, risk management, hydrothermal market modelling and hydropower scheduling models. The internal audit concluded that:

- BC Hydro has a well-established Energy Studies process in place;
- Key models are appropriate; and
- The methodologies applied are in line with leading industry practices.

The internal audit report is provided as Appendix DD. Further information is provided in Chapter 4, section 4.4.2.

[15] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 28.

1.5.8 We Are Taking Steps to Reduce IPP Costs

In its Decision, the BCUC observed that there is a potential for cost savings if additional IPP contracts are canceled or amended to reduce the volume of IPP purchases.[16] The BCUC also recommended that BC Hydro consider the timing of its existing IPP contracts and contract renewals.[17]

BC Hydro's forecast increases to our Cost of Energy are primarily driven by increasing IPP energy costs under existing agreements. BC Hydro is not acquiring new resources from IPPs, with the exception of a small number of new First Nations energy projects and some EPA renewals, such as new contracts under the Biomass Energy Program. The forecast increase in IPP energy costs from fiscal 2019 to fiscal 2021 is in large part due to pre-determined factors, including price escalation terms and other terms in existing EPAs, and IPP projects with existing EPAs reaching commercial operation.

BC Hydro and the Government of B.C. have taken steps since fiscal 2015 to reduce IPP power acquisitions. These steps include the indefinite suspension of the SOP, terminating three EPAs, and not renewing three other EPAs that expired. Further information is provided in Chapter 4, section 4.3.2.

1.5.9 We Have Clarified Our Accounting Treatment for Costs of Energy

In its Decision, the BCUC directed BC Hydro to explain, in a compliance filing, the accounting treatment of surplus energy costs and recoveries.[18]

BC Hydro's Cost of Energy was previously categorized into Heritage Energy and Non Heritage Energy. This practice stems from the Heritage Contract, which was recently repealed as a result of the Government of B.C.'s Comprehensive Review.

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[16] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 26.

[17] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 28.

[18] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 112.

The categorization under the Heritage Contract never had any practical impact on BC Hydro's planning and operations. The financial treatment of these costs was the same regardless of how they were categorized. Similarly, the repeal of the Heritage Contract has no impact on BC Hydro's planning or operations or the financial treatment. BC Hydro continues to manage all sources of energy supply as a single portfolio. However, without the Heritage Contract, BC Hydro now has the flexibility to categorize its Cost of Energy differently in its revenue requirements model for this application. In Schedule 4.0 of Appendix A to this application, which sets out BC Hydro's Cost of Energy, BC Hydro has re-categorized its Cost of Energy into: Heritage Energy, Non-Heritage Energy and Market Energy.

These categories are for presentation purposes only and are intended to provide better clarity on the presentation of our Cost of Energy. We believe that these categories will make it easier to understand BC Hydro's energy costs. Further information is provided in Chapter 4, section 4.2.1.

1.5.10 We Are Providing More Detailed Information on Our Operating Costs

In its Decision, the BCUC stated that it did not have a high degree of comfort in BC Hydro's overall operating costs, due to its limited involvement in the approval of BC Hydro's previous revenue requirements.[19]

In response to the BCUC's observation, we have provided significantly more information on our operating costs, relative to the Previous Application. We address the composition, drivers and outcomes of the overall budget of each KBU, not just incremental amounts. This information is contained in Chapters 5A through 5G.

[19] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 33.

1.5.11 FTE Increases Are Driven by Capital Investment and Have Reduced BC Hydro's Overall Costs

In its Decision, the BCUC reviewed BC Hydro's headcount over time.[20]

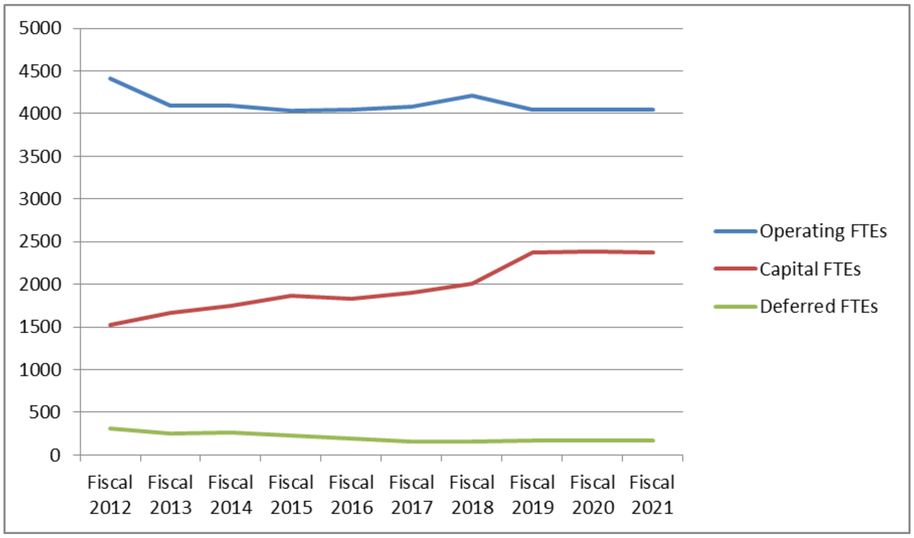
The growth in Full Time Equivalents (**FTEs**) in recent years has actually been a source of cost savings:

- The Workforce Optimization Program, discussed in Chapter 5, section 5.6.1, has replaced higher cost contractors with internal FTEs, generating an estimated $18.5 million in annual savings.
- The Accenture repatriation, discussed in Chapter 5 ,section 5.6.2, has exceeded the anticipated cost savings.

In addition, as shown in Figure 1-3 below, apart from growth in the workforce directly related to increased capital investment, BC Hydro's FTEs have remained relatively flat since fiscal 2012. This includes additions related to the Workforce Optimization Program.

[20] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 34.

Figure 1-3 FTEs[21,22] (Fiscal 2012 to Fiscal 2021)



	Fiscal 2012 Actual	Fiscal 2013 Actual	Fiscal 2014 Actual	Fiscal 2015 Actual	Fiscal 2016 Actual	Fiscal 2017 Actual	Fiscal 2018 Actual	Fiscal 2019 Forecast	Fiscal 2020 Plan	Fiscal 2021 Plan
Operating	4,415	4,096	4,089	4,036	4,042	4,082	4,209	4,051	4,047	4,043
Capital	1,527	1,662	1,752	1,872	1,828	1,905	2,013	2,378	2,383	2,370
Deferred	309	250	258	223	188	161	162	165	164	164
Total FTEs	**6,251**	**6,007**	**6,099**	**6,131**	**6,058**	**6,148**	**6,385**	**6,593**	**6,594**	**6,577**

Excluding the Site C Project, FTEs are planned to remain flat during the test period. Further information is provided in Chapter 5 section 5.6.3 and section 5.6.4.

1.5.12 Workforce Optimization Program Considers Long-Term Effects and Costs

In July 2015, BC Hydro launched a Workforce Optimization Program to determine the right mix of internal and external labour resources. In its Decision, the BCUC

[21] Figure 1-3 shows total FTEs by work function (operating, capital or deferred), excluding FTEs related to the Accenture Repatriation, the Smart Metering Infrastructure Project and the Site C Project. These FTEs were removed to avoid skewing the trend line. All FTEs related to the Workforce Optimization Program are included. The numbers for Fiscal 2012 to Fiscal 2018 are actuals. Fiscal 2019 numbers are forecast and Fiscal 2020 and 2021 numbers are plan.

[22] "Deferred" FTEs, refers to FTEs whose work is charged to regulatory accounts (e.g., the DSM Regulatory Account).

observed that there did not appear to be an assessment of the long-term effects and costs of hiring contractors as employees.[23]

Decisions to replace external contractors with internal FTEs, through the Workforce Optimization Program, must be supported by a workforce adjustment request document. The documents provide both quantitative and qualitative support for converting a contractor to an employee.

The documentation required by the Workforce Optimization Program accounts for both the short-term and long-term effects and costs of hiring contractors as employees. Specifically, workforce adjustment request documents consider:

- The costs of hiring internal employees against the costs of contracting out work to an external supplier. The costs of internal employees, measured by using Standard Labour Rates, includes base salary and wages, premiums, overtime, vacation/flex time, pension, employer-paid premiums, insurance, supplemental benefits and training;
- Other implications of employing internal resources such floor space requirements; and
- Non-financial benefits such as maintaining knowledge about assets or programs in-house and establishing strong succession plans for potential retirements.

In addition, BC Hydro uses resource forecasts to determine our long-term labour needs. This includes assessing our current internal resources and external suppliers' abilities to meet the needs of our capital and maintenance plans. Further information is provided in Chapter 5, section 5.6.1.3.

[23] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 34.

1.5.13 Our Total Rewards Package Helps to Retain Employees and is Consistent with Market Rates

In its Decision, the BCUC stated that the costs and benefits of BC Hydro's total rewards initiatives were unclear.[24] BC Hydro's total rewards offer includes salary, pension, benefits and time-off (i.e., vacation). It is designed to attract and retain qualified employees. A 2017 total rewards assessment by Morneau Shepell concluded:

- On an average total cash basis, BC Hydro employees earn 11 per cent less than median market rates; and
- After factoring in the value of pension benefits and time off programs, BC Hydro's compensation package is comparable, at 2 per cent below median market rates.

BC Hydro believes that an emphasis on non-salary compensation measures (i.e., pension and time-off) improves employee retention. In fact, our voluntary turnover rate is 1.3 per cent, which is below the 3.8 per cent average for the Power and Utilities industry as reported by the Conference Board of Canada. [25] Further information is provided in Chapter 5, section 5.6.5.2.

1.5.14 Using Work Smart Gains to Address Workload and Absorb New Work is Valuable and Consistent with Practices at Other Companies

In its Decision, the BCUC expressed its belief that the efficiency savings generated by BC Hydro's Work Smart program should result in incremental cost savings.[26]

As of the end of fiscal 2018, BC Hydro has realized an estimated 80,000 annual capacity hours gained as a result of Work Smart program initiatives. The estimated

[24] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 34.

[25] MacLean, Kathryn, and Allison Cowan. *Compensation Planning Outlook 2019*. Ottawa: The Conference Board of Canada, 2018.

[26] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 34.

realized annual savings exceed the forecast amount of 46,550 hours provided by BC Hydro in the Previous Application.[27]

We believe that our approach of using these gains to address workload issues and absorb new work, so that new costs can be avoided, is beneficial. Efficiency gains through the Work Smart program are an important part of our efforts to keep operating cost increases below the rate of inflation.

Work Smart relies on front-line employees to identify opportunities to make processes more efficient and effective as well as to save time and resources. We believe that using the gains from these opportunities to address workload issues and allow employees to focus on higher value work is the most effective way to encourage employees to bring forward ideas and participate in the Work Smart process.

BC Hydro's approach of using Work Smart gains to address workload issues is also consistent with practices at other companies such as the Insurance Corporation of British Columbia and Washington State. Further information is provided in Chapter 5, section 5.4.5.

1.5.15 BC Hydro Uses Benchmarking and Our Operating and Maintenance Costs Benchmark Favourably

In its Decision, the BCUC expressed concern with the apparent lack of metrics used by BC Hydro for productivity or benchmarking purposes.[28] Although BC Hydro did not present evidence on metrics and benchmarking in the last Application, we use them on a regular basis across parts of the organization. We have also augmented that information with benchmarking prepared specifically for this proceeding.

[27] Refer to BC Hydro's Response to BCUC IR 2.213.04 in the Previous Application proceeding.

[28] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 87.

- A report prepared by The Brattle Group, provided as Appendix T, shows that BC Hydro's operating costs benchmark favourably against a peer group of U.S. utilities;
- An internal analysis provides an indicative assessment that BC Hydro's operating costs compare well against those of other major Canadian utilities;
- Recent benchmarking on maintenance delivery costs has demonstrated that BC Hydro's costs are consistent with or better than its utility peers; and
- Cost benchmarking and metrics are used in other areas of the business.

Further information on benchmarking is provided in Chapter 5, section 5.7.

1.5.16 We Have Developed a Benefits Realization Process for Technology Investments

In its Decision, the BCUC stated that it was unclear on the types of analysis performed by BC Hydro to support its technology investments. The BCUC also stated it was unable to assess how technology investments would result in quantifiable efficiencies and cost savings.[29]

BC Hydro has implemented a benefits realization process for technology projects. This process is in place so that:

- Benefits claimed in business cases are realized once projects are in service; and
- Ownership for benefits included in technology project business cases extends beyond project completion.

Further information is provided in Chapter 6, section 6.5.5.

[29] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 34.

1.5.17 This Application Identifies Projects that Are Expected to be Subject to a CPCN Proceeding

In its Decision, the BCUC noted that it reviews large planned projects to identify projects that have potentially significant public interest issues requiring further investigation through separate Certificate of Public Convenience and Necessity (**CPCN**) processes.[30] Appendix I of this application indicates which projects BC Hydro expects to be subject to a future CPCN or section 44.2 proceeding.

1.5.18 BC Hydro Has Well Established and Well Performing Practices for the Planning and Delivery of Capital Investments

In its Decision, the BCUC recommended that the adequacy of BC Hydro's planning and execution related to large capital projects be explored.[31] We have done so in this application.

BC Hydro has well-established and well-performing practices for the planning and delivery of capital investments:

- In December 2018, the Office of the Auditor General of B.C. released an independent audit of Capital Asset Management in BC Hydro. The audit found that BC Hydro has good asset management practices as a result of a decade long plan and associated efforts. It had no recommendations for improvement. This audit is included as Appendix F.
- In 2016, BC Hydro completed its second Organizational Project Management Maturity Model Assessment and placed in the top tier of participating organizations from around the world.

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[30] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 39.

[31] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 45.

- Also in 2016, BC Hydro received the Project Management Office of the Year Award from the Project Management Institute, recognizing superior organizational project management capabilities.

A key metric to evaluate BC Hydro's performance in the delivery of capital projects is to compare the actual project costs for in-service projects to the original approved expected cost over an aggregated five-year period. Projects included in this metric for the five-year period of fiscal 2014 to fiscal 2018 had an aggregate original approved expected cost of $6.936 billion. The actual aggregate costs for these projects were $27.9 million (or 0.40 per cent) over the original approved expected cost. Since 2014, when BC Hydro began measuring its capital delivery performance with a five-year aggregate, it has been in the range of –4.75 per cent to +0.40 per cent of the original approved expected cost.

In recent years, BC Hydro has also implemented changes to further improve the delivery of large capital projects.

Further information is provided in Chapter 6, section 6.2.1.

1.5.19 We Have Provided Additional Information on Capital Expenditures and Additions

On June 13, 2018, BC Hydro filed its Revised Proposal in the Capital Expenditures and Projects Review proceeding. The BCUC established that proceeding to examine how it reviews BC Hydro's capital expenditures and projects. While that proceeding is ongoing, the information provided in this application reflects BC Hydro's Revised Proposal, which included additional information to address concerns identified in the scope of that proceeding. Further information is provided in Chapter 6, section 6.2.2.

1.5.20 Emergency RipRap Costs Are Prudent

On November 13, 2015, BC Hydro filed an application with the BCUC to upgrade the riprap on the W.A.C. Bennett Dam. The BCUC accepted the project's expenditure schedule with the exception of the costs associated with a Maintenance and

Emergency Stockpile (MES) of riprap. The BCUC directed that, in future revenue requirement applications, BC Hydro either confirm that no expenditures relating to the emergency stockpile riprap are included in the revenue requirements or explain otherwise. [32] In August 2017, BC Hydro notified the BCUC that it was proceeding with expenditures for the MES. BC Hydro believes these expenditures are prudent and is seeking to recover the total riprap costs of $0.7 million as part of the forecast revenue requirements outlined in this application. Further information is provided in Chapter 6, section 6.4.13.5.

1.5.21 BC Hydro's Use of Regulatory Accounts is Consistent with BCUC Directives

In its Decision, the BCUC issued several directives with regards to BC Hydro's regulatory accounts. BC Hydro is managing all of its regulatory accounts consistent with these directives and is not requesting any changes to those directives in this application. Further information is provided throughout Chapter 7.

1.5.22 Continued Use of the Dismantling Cost Regulatory Account is Appropriate

In its Decision, the BCUC approved BC Hydro's request to establish a Dismantling Cost Regulatory Account for the fiscal 2017 to fiscal 2019 test period. The BCUC stated that, in its view, the timing of dismantling activities is largely within BC Hydro's control but that the establishment of the account for the test period would allow BC Hydro to gain more experience with forecasting the timing of expenditures.[33]

BC Hydro believes continued use of the Dismantling Cost Regulatory Account is appropriate. In BC Hydro's view, the nature of dismantling costs makes them difficult to forecast accurately. Dismantling cost variances can be positive or negative and have ranged from $14.1 million below plan to $31.7 million above plan since

[32] BCUC Order No. G-78-16, Appendix A, page 44.
[33] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), pages 62 to 63.

fiscal 2012. Dismantling costs are largely driven by BC Hydro's capital plan and are impacted by capital project schedules. In the absence of a regulatory account to capture variances between forecast and actual dismantling expenditures, significant gains or losses could accrue to ratepayers or the Government of B.C. Continued use of the account will mean that ratepayers pay the actual costs of any dismantling activities. Further information is provided in Chapter 7, section 7.7.2.

1.5.23 We Are Requesting BCUC Approval to Close the Rate Smoothing Regulatory Account

In its Decision, the BCUC raised concerns about the Rate Smoothing Regulatory Account and the apparent decoupling of revenues and expenditures during the test period.[34] In previous fiscal years, as part of the Government of B.C.'s 2013 10 Year Rates Plan, BC Hydro deferred a portion of its approved revenue requirement to the Rate Smoothing Regulatory Account for collection in rates in future fiscal years. This kept rates lower than they otherwise would have been. As a result of the Comprehensive Review, BC Hydro ceased using the Rate Smoothing Regulatory Account and wrote off the balance in the account in fiscal 2019. In this application, we are requesting BCUC approval to close the account. This means that BC Hydro's revenues and expenditures are no longer decoupled. Further information is provided in Chapter 7, section 7.7.6.

1.5.24 We Increased Residential Demand-Side Management Programs

In its Decision, the BCUC directed BC Hydro to consider more targeted DSM programs directed at residential customers.[35] In response, BC Hydro's proposed DSM expenditure schedule increases expenditures for the residential sector by approximately 50 per cent. This increase was funded through re-allocations from other sectors and did not increase overall DSM expenditures. In addition,

[34] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 110.

[35] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), Directive 21.

participation targets for the Low-Income Program have been increased and additional measures and increased incentives have been added to the Home Renovation Rebate Program. Further information is provided in Chapter 10, section 10.2.2.

1.5.25 We Have Reviewed Industry Practice for Codes and Standards Attribution

In its Decision, the BCUC directed BC Hydro to review if its approach for attributing savings that occur from the implementation of codes and standards was consistent with industry practice.[36] BC Hydro retained the Cadmus Group to conduct an assessment, which is included as Appendix CC. This assessment concluded that industry practice on codes and standards attribution is varied and evolving and that the different approaches reflect the different regulatory and business drivers facing utilities. BC Hydro's approach is consistent with other Canadian jurisdictions such as Manitoba and Ontario. In this application, we have taken steps to improve the presentation of our treatment of codes and standards savings. Further information is provided in Chapter 10, section 10.2.3.

1.5.26 We Have Launched a New DSM Program for Non-Integrated Areas

In its Decision, the BCUC acknowledged concerns raised by the Non-Integrated Areas Ratepayers Group (**NIARG**) and the Zone II ratepayers group (**Zone II**) regarding DSM activities in non-integrated areas. The BCUC also directed BC Hydro to provide certain information on DSM activities in non-integrated areas in its Annual Report on DSM Activities and in this application.[37]

- In response, BC Hydro has launched a new Non-Integrated Areas program. Further information on this program is provided in Chapter 10, section 10.2.4.

[36] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), Directive 22.

[37] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), Directive 23.

- Appendix Z provides BC Hydro's F2018 Annual Report on DSM Activities. This report includes a new section to track activities in non-integrated areas separately.
- Appendix X provides BC Hydro's Fiscal 2020 to Fiscal 2022 DSM Business Plan. This appendix includes an estimate of the difference in cost-effectiveness test results of programs available to customers in the non-integrated areas compared to the integrated areas.

1.5.27 We Have Considered the Adoption of Performance Based Regulation

In its Decision, the BCUC directed BC Hydro to file a report on Performance Based Regulation (**PBR**).[38] This PBR Report is provided as Chapter 11 of this application.

To assist us in identifying the opportunities and challenges associated with the adoption of PBR for BC Hydro, we retained Dr. Dennis Weisman, Ph.D., a recognized expert in PBR.

- Appendix FF provides a whitepaper completed by Dr. Weisman at BC Hydro's request titled "A Report on the Theory and Practice of Performance Based Regulation."; and
- Appendix GG provides a paper that Dr. Weisman previously co-wrote with Dr. David Sappington titled "Assessing the Treatment of Capital Expenditures in Performance Based Regulation Plans."

We have reviewed the potential implications of adopting PBR and concluded that, at this time, BC Hydro should continue to be regulated through cost of service regulation.

[38] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), Directive 28.

BC Hydro respectfully recommends that the BCUC use this Revenue Requirements Application proceeding to engage interveners to canvass their views.

Should the BCUC decide to adopt PBR for BC Hydro, this report provides initial conclusions in response to the issues the BCUC has asked BC Hydro to address. These initial conclusions provide a framework for a PBR plan.

1.6 Summary of Orders Sought

In this application, we are seeking approval to amend BC Hydro's rate schedules as follows:

- A reduction of the Deferral Account Rate Rider (**DARR**) from 5 per cent to 0 per cent on April 1, 2019; and
- Permanent general increases of 6.85 per cent on April 1, 2019 (for fiscal 2020) and 0.72 per cent on April 1, 2020 (for fiscal 2021).

The reduction of the DARR from 5 per cent to 0 per cent on April 1, 2019 would offset the proposed general rate increase for fiscal 2020. As a result, if approved, these requests would result in a net bill increase of 1.76[39] per cent on April 1, 2019. The net bill increase on April 1, 2020 would be the same as the proposed general rate increase of 0.72 per cent.

We request that these changes be made effective April 1, 2019, on an interim basis, pending a final BCUC decision on our Application. Tariff Sheets reflecting these requests are provided in Appendix EE.

[39] Offsetting the requested general rate increase of 6.85 per cent with the requested reduction of the DARR from 5 per cent to 0 per cent reduces the net bill increase by more than 5 per cent because the DARR is applied after general rate increases. The following equation demonstrates how this works:
Start: Bill with 5 per cent DARR: $105.00
Adjust: DARR from 5 per cent to 0 per cent: $100.00
Adjust: General Rate Increase of 6.85 per cent: $106.85
$106.85/$105.00 = 1.0176

Second, this application also contains requests related to BC Hydro's regulatory accounts. Specifically, this application requests BCUC approval to:

- Refund the forecast fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts, over the fiscal 2020 to fiscal 2021 test period. This would result in a net credit to the benefit of ratepayers of $329.1 million being amortized into rates during the test period;
- Defer any variances related to the accounting for EPAs determined to be leases under IFRS 16, which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account;
- Defer any variances between forecast and actual amounts related to the Biomass Energy Program, which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account. This will ensure BC Hydro recovers its costs with respect to the Biomass Energy Program;[40]
- Continue to defer, on an annual and ongoing basis, any variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account, continue to apply interest to the balance of the account and recover the forecast interest charged to the account each year, and continue to recover the forecast account balance at the end of a test period over the next test period;
- Defer low-carbon electrification expenditures to the DSM Regulatory Account, consistent with the Direction to the BCUC Respecting Undertaking Costs;
- Remove the reference to the "Prescribed Standards" from the scope of what may be deferred to the Site C Regulatory Account, as BC Hydro has fully adopted IFRS. This will allow BC Hydro to continue to defer to the Site C

[40] The Government of B.C. has indicated that it intends to provide a direction to the BCUC with respect to the approval of the program documentation and to require the costs associated with the program to be recovered from ratepayers.

Regulatory Account any costs related to the Site C Project that are not able to be capitalized;

- Close the Capital Project Investigation Costs Regulatory Account at the end of fiscal 2021 as its balance will be fully amortized into rates at that time; and
- Close the Rate Smoothing Regulatory Account in fiscal 2020 as this account has a zero balance and BC Hydro is not proposing to smooth rates over the fiscal 2020 to fiscal 2021 test period.

Further information on requests related to BC Hydro's regulatory accounts is provided in Chapter 7, section 7.7.

Third, this application also requests BCUC approval of:

- Depreciation rates for the Burrard synchronous condense facility, for new Water Rights, Infrastructure Rights and LED Streetlights asset classes and for three new asset classes for agreements recognized as leases under International Financial Reporting Standard 16, *Leases*. For further information on this request, please refer to Chapter 8, section 8.2;
- Open Access Transmission Tariff (**OATT**) rates, as set out in Chapter 9, Table 9-8. For further information on this request, please refer to Chapter 9; and
- A DSM expenditure schedule of $90.8 million in fiscal 2020 and $116.3 million in fiscal 2021. For further information on this request, please refer to Chapter 10.

Fourth, this application requests that the BCUC reconsider and vary Directive 3 of the BCUC's Decision on BC Hydro's Fiscal 2017 to Fiscal 2019 Revenue Requirements Application which, among other things, directs BC Hydro to file a CPCN application for the Northwest Substation Upgrade project. This directive is inconsistent with the Transmission Upgrade Exemption Regulation. Further information is provided in Chapter 2, section 2.5.8.

Fifth, this application requests that the BCUC reconsider and rescind the following directives:

- Directive 61 of the BCUC's Decision on BC Hydro's Fiscal 2005 to Fiscal 2006 Revenue Requirements Application which directs that a prorated amount of costs from portfolio-level initiatives be added to the cost of each DSM program to assess cost effectiveness. This Directive is inconsistent with industry practice and with section 4 of the DSM regulation which was put in place after the Directive was issued. In addition, it requires a calculation that does not provide a fair assessment of the cost-effectiveness of a program and makes it challenging for some programs to be cost-effective. Further information is provided in Chapter 10, section 10.5.4.
- Directive 57 of the BCUC's Decision on BC Hydro's Fiscal 2009 to Fiscal 2010 Revenue Requirements Application which directs that BC Hydro revenue requirement applications filed after January 1, 2011 contain financial information that follows the Uniform System of Accounts. Based on conversations with BCUC staff, BC Hydro understands that the BCUC does not see a need for BC Hydro to continue providing this information in its revenue requirement applications. Accordingly, this application does not contain this information.

Chapter 2, section 2.9 provides a summary of the BCUC's legal authority with regards to these requested approvals. A Draft Order is provided in Appendix B.

1.7 Overview of BC Hydro's Revenue Requirements

This section provides an overview of our revenue requirements for fiscal 2020 and fiscal 2021 and shows the revenue shortfall that will result from the existing rates. BC Hydro requires a rate increase in order to generate the necessary revenues to provide safe and reliable service during the test period.

There are two ways to summarize BC Hydro's revenue requirements:

- **Gross View:** The Gross View shows the total costs for each component of the revenue requirements before any forecast transfers to regulatory accounts and then shows the regulatory account transfers as a separate total. In other words, “Gross View” shows the total costs incurred in fiscal 2020 and fiscal 2021.
- **Current View:** The Current View shows the total costs for each component of the revenue requirements after any forecast transfers to regulatory accounts. In other words, the “Current View” shows the actual costs being recovered from customers in rates in fiscal 2020 and fiscal 2021.

Appendix A contains the detailed financial schedules of our revenue requirements model and is intended to provide a single location for all costs contained in our Application. The working revenue requirements model that produces these schedules is also provided in electronic form as part of this filing. A reconciliation of the Gross View and the Current View for each component of the revenue requirements is provided in Schedule 3.0 of Appendix A.

1.7.1 Increased Gross Revenue Requirements Are Primarily Driven By An End to Rate Smoothing and Higher Cost of Energy

Table 1-3 below shows BC Hydro's revenue requirements for fiscal 2020 and fiscal 2021 from a Gross View.

Table 1-3 Gross View of BC Hydro's Revenue Requirements[41]

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Cost of Energy	1.0 L1	1,549.3	1,505.5	1,657.8	1,538.7	1,762.9	1,673.4	1,887.0	1,920.2
2	Operating Costs	1.0 L2	1,185.0	1,165.1	1,220.0	1,228.7	1,221.0	1,257.5	1,224.2	1,229.3
3	Taxes	1.0 L3	223.3	223.1	231.8	231.1	238.7	242.2	249.8	262.2
4	Amortization	1.0 L4	783.2	777.9	821.1	807.6	850.9	871.5	915.7	936.5
5	Finance Charges	1.0 L5	708.8	579.2	735.0	805.9	773.8	684.6	757.5	726.9
6	Return on Equity	1.0 L6	684.0	683.5	698.0	684.0	712.0	(424.3)	712.0	712.0
7	Miscellaneous Revenue	1.0 L7	(137.1)	(143.1)	(138.3)	(143.7)	(140.6)	(202.9)	(240.8)	(247.2)
8	Inter-Segment Revenue	1.0 L8	(62.5)	(56.9)	(64.3)	(66.4)	(65.3)	(64.3)	(69.0)	(72.6)
9	Deferral Account Transfers	1.0 L12	182.0	245.8	197.0	410.4	215.3	460.2	(152.5)	(158.1)
10	Other Regulatory Account Transfers	1.0 L16	(285.9)	(138.0)	(358.1)	(461.2)	(346.8)	804.2	125.3	131.9
11	Subsidiary Net Income	1.0 L19	(119.7)	(132.4)	(119.9)	(139.6)	(120.2)	(208.6)	(124.0)	(124.3)
12	Other Utilities Revenue	1.0 L20	(12.6)	(13.0)	(12.0)	(11.9)	(12.1)	(28.6)	(28.6)	(28.7)
13	Liquefied Natural Gas Revenue	1.0 L21	(4.4)	(0.4)	(10.7)	(1.3)	(10.9)	(0.3)	0.0	0.0
14	Deferral Rider Revenue	1.0 L22	(223.5)	(223.7)	(231.3)	(233.2)	(241.8)	(241.2)	0.0	0.0
15	Total Rate Revenue Requirement	1.0 L23	4,469.9	4,472.6	4,626.1	4,649.1	4,836.8	4,823.4	5,256.5	5,288.3
16	Less Revenue at F2019 Rates	1.0 L28	(4,469.9)	(4,472.6)	(4,626.1)	(4,649.1)	(4,836.8)	(4,823.4)	(4,919.6)	(4,913.7)
17	Revenue Shortfall	1.0 L29	0.0	0.0	(0.0)	0.0	0.0	0.0	336.9	374.5
18	Annualized Rate Increase	1.0 L30	4.00%	4.00%	3.50%	3.50%	3.00%	3.00%	6.85%	0.72%
19	Deferral Account Rate Rider	1.0 L31	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	0.00%	0.00%
20	Net Bill Increase	1.0 L32	4.00%	4.00%	3.50%	3.50%	3.00%	3.00%	1.76%	0.72%

Table 1-4 below provides an explanation of the difference between the fiscal 2019 RRA and the fiscal 2021 plan amounts, based on the Gross View. This provides a summary of the key differences between the revenue requirements in this

[41] Forecast BC Hydro contributions to Government in fiscal 2020 are approximately $1.3 billion and include taxes (line 3 above, which includes amounts paid to the Province and municipalities), return on equity (line 6 above) and water rentals (part of line 1 above; in fiscal 2020 the forecast amount is $347 million and can be seen by adding lines 23 and 32 of Appendix A, Schedule 4.0).

application and the revenue requirements approved by the BCUC in the Previous Application.

Table 1-4 Explanation of Differences Between Fiscal 2019 RRA and Fiscal 2021 Plan (Gross View)

Cost Component and References	Difference ($ million)	Explanation
Cost of Energy Chapter 4 Appendix A, Schedule 4.0	157.3	Cost of Energy is increasing, primarily because of cost increases on existing IPP contracts due to operational changes, price escalation, capacity increases and forecast delivery changes.
Operating Costs Chapter 5 Appendix A, Schedule 5.0	8.3	BC Hydro is limiting base operating cost increases below the forecast rate of inflation, by offsetting non-controllable cost increases with reductions to controllable costs.
Taxes Chapter 8, Section 8.6 Appendix A, Schedule 6.0	23.5	Four factors are increasing the taxes paid by BC Hydro: increased assessed property values, the completion of new capital projects that are subject to taxation, increased grants-in-lieu due to an increase in forecast electricity sales and increases to provincial and municipal taxation rates.
Amortization Chapter 8, Section 8.2 Appendix A, Schedule 7.0	85.6	Two factors are driving increased amortization costs during the test period. First, BC Hydro’s forecast capital additions have increased as a result of recent capital investments. Second, in 2018, the BCUC approved BC Hydro’s purchase of the remaining two-thirds interest in the Waneta Dam.
Finance Charges Chapter 8, Section 8.5 Appendix A, Schedule 8.0	(46.9)	Forecast interest during construction has increased, which decreases finance charges. This decrease is partially offset by an increase in forecast borrowing costs, primarily due to recent capital expenditures.
Return on Equity Chapter 8, Section 8.3 Appendix A, Schedule 9.0	0	Section 8 of Direction No. 8 states that the BCUC must set BC Hydro’s Return on Equity at $712 million for fiscal 2020 and fiscal 2021. This amount is equal to the amount for fiscal 2019.
Miscellaneous Revenue Chapter 8, Section 8.7 Appendix A, Schedule 15.0	(106.6)	Miscellaneous revenues reduce overall revenue requirements and are planned to increase during the test period, primarily due to lease and other revenues related to BC Hydro’s acquisition of the remaining two-thirds interest in the Waneta Dam.
Inter-Segment Revenue Chapter 8, Section 8.8 Appendix A, Schedule 3.0	(7.2)	Inter-segment revenues are relatively consistent from fiscal 2019 RRA to fiscal 2021 plan.
Deferral Account Transfers Chapter 7 , section 7.7.1 Appendix A, Schedule 2.1	(373.4)	The decrease in deferral account transfers reflects BC Hydro’s request for BCUC approval to refund the forecast fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts, over the test period.

Cost Component and References	Difference ($ million)	Explanation
Other Regulatory Account Transfers Chapter 7 Appendix A, Schedule 2.2	478.7	The increase in other regulatory account transfers primarily reflects that BC Hydro is no longer using, and is requesting BCUC approval to close the Rate Smoothing Regulatory Account. Transfers to this account were $321 million for fiscal 2019 RRA and are $0 in fiscal 2020 and fiscal 2021 plan.
Subsidiary Net Income Chapter 8, Section 8.9 Appendix A, Schedule 1.0	(4.1)	The inclusion of subsidiary net income in BC Hydro's revenue requirements reduces the overall revenue requirements. Subsidiary net income includes net income from BC Hydro's energy trading subsidiary Powerex as well as our subsidiary Powertech. Subsidiary net income is increasing, primarily due to an increase in the five-year average that is used to forecast Trade Income.
Other Utilities Revenue Chapter 8, Section 8.13.2 Appendix A, Schedule 14.0	(16.6)	The inclusion of Other Utilities Revenue in BC Hydro's revenue requirements reduces the overall revenue requirements. Other Utilities Revenue is increasing, primarily due to the adoption of IFRS 15 which impacts the accounting of payments made by Seattle City Light under the terms of the Skagit River Agreement.
Liquefied Natural Gas Revenue Chapter 2, Section 2.5.9 Appendix A, Schedule 14.0	10.9	In October 2018, the Government of B.C. removed a previous provision that prevented LNG customers from receiving service under BC Hydro's transmission rate schedules. This means that revenue from LNG customers is now recorded as general rate revenue and not as a separate line item.
Deferral Rider Revenue Chapter 7 Appendix A, Schedule 14.0	241.8	The decrease in DARR revenue reflects BC Hydro's request for BCUC approval to reduce the DARR from 5 per cent to 0 per cent on April 1, 2019.

1.7.2 BC Hydro's Requested Bill Increase is Primarily Driven by an End to Rate Smoothing and Increased Capital Investment

Table 1-5 below shows BC Hydro's revenue requirements for fiscal 2020 and fiscal 2021 from a Current View.

Table 1-5 Current View of BC Hydro's Revenue Requirements

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Cost of Energy	3.0 L12	1,723.9	1,715.8	1,838.6	1,854.1	1,951.8	1,933.5	1,735.1	1,768.2
2	Operating Costs	3.0 L21	984.2	990.9	953.8	972.8	961.6	2,107.1	1,298.6	1,305.2
3	Taxes	3.0 L24	223.3	223.5	231.8	232.9	238.7	242.2	249.8	262.2
4	Amortization	3.0 L30	860.7	860.7	917.5	916.3	955.3	950.8	1,035.6	1,060.2
5	Finance Charges	3.0 L37	504.6	504.0	512.4	513.1	555.5	555.6	697.5	662.3
6	Return on Equity	3.0 L41	684.0	683.5	698.0	684.0	712.0	(424.3)	712.0	712.0
7	Miscellaneous Revenue	3.0 L46	(137.1)	(143.4)	(138.3)	(143.7)	(140.6)	(151.6)	(237.7)	(243.7)
8	Inter-Segment Revenue	3.0 L51	(62.5)	(56.9)	(64.3)	(66.4)	(65.3)	(64.3)	(69.0)	(72.6)
9	Subsidiary Net Income	3.0 L69	(70.8)	(68.4)	(69.3)	(67.7)	(67.3)	(55.6)	(136.6)	(136.9)
10	Other Utilities Revenue	3.0 L70	(12.6)	(13.0)	(12.0)	(11.9)	(12.1)	(28.6)	(28.6)	(28.7)
11	Liquefied Natural Gas Revenue	3.0 L71	(4.4)	(0.4)	(10.7)	(1.3)	(10.9)	(0.3)	0.0	0.0
12	Deferral Rider Revenue	3.0 L72	(223.5)	(223.7)	(231.3)	(233.2)	(241.8)	(241.2)	0.0	0.0
13	Total Rate Revenue Requirement	3.0 L73	4,469.9	4,472.6	4,626.1	4,649.1	4,836.8	4,823.4	5,256.5	5,288.3
14	Less Revenue at F2019 Rates	1.0 L28	(4,469.9)	(4,472.6)	(4,626.1)	(4,649.1)	(4,836.8)	(4,823.4)	(4,919.6)	(4,913.7)
15	Revenue Shortfall	1.0 L29	0.0	0.0	(0.0)	0.0	0.0	0.0	336.9	374.5
16	Annualized Rate Increase	1.0 L30	4.00%	4.00%	3.50%	3.50%	3.00%	3.00%	6.85%	0.72%
17	Deferral Account Rate Rider	1.0 L31	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	0.00%	0.00%
18	Net Bill Increase	1.0 L32	4.00%	4.00%	3.50%	3.50%	3.00%	3.00%	1.76%	0.72%

Table 1-6 below provides an explanation of the difference between the fiscal 2019 RRA and the fiscal 2021 plan amounts, based on the Current View. This provides a summary of the key differences between the revenue requirements in this application and the revenue requirements approved by the BCUC in the Previous Application.

Table 1-6 Explanation of Differences Between Fiscal 2019 RRA and Fiscal 2021 Plan (Current View)

Cost Component and References	Difference ($ million)	Explanation
Cost of Energy Chapter 4 Appendix A, Schedule 4.0	(183.6)	Current cost of energy is decreasing, primarily because BC Hydro is requesting BCUC approval to refund the credit balance in the Heritage Deferral Account and the Non-Heritage Deferral Account to ratepayers. These accounts are used to capture variances between forecast and actual cost of energy and are discussed further in Chapter 7, section 7.7.1. Gross cost of energy is increasing during the test period, primarily due to an increase in costs associated with IPPs and Long-Term Commitments.
End to Rate Smoothing Chapter 7, Section 7.7.6 Appendix A, Schedule 5.0	321.4	In previous fiscal years, BC Hydro deferred a portion of its approved revenue requirements to the Rate Smoothing Regulatory Account, for collection in rates in future fiscal years. This kept rates lower than they otherwise would have been. In its Decision Previous Application, the BCUC raised concerns about this approach and its apparent decoupling of revenues and expenditures.[42] In this application, BC Hydro is requesting BCUC approval to close the Rate Smoothing Regulatory Account. Transfers to the Rate Smoothing Regulatory Account represented a pool of costs, with no identification of what specific costs made-up the transfer amount. For presentation purposes, these transfers were shown as negative recoveries from regulatory accounts and included in the Operating Costs component of the Current View. Therefore the increase to Operating Costs from fiscal 2019 RRA to fiscal 2020 plan is primarily due to the absence of transfers to the Rate Smoothing Regulatory Account. The fiscal 2019 forecast amount reflects the write-off of the Rate Smoothing Regulatory Account.

[42] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 110.

Cost Component and References	Difference ($ million)	Explanation
Operating Costs (net of Rate Smoothing) Chapter 5 Appendix A, Schedule 5.0	22.2	BC Hydro is limiting base operating cost increases[43] below the forecast rate of inflation,[44] by offsetting non-controllable cost increases with reductions to controllable costs. Three factors are driving most of BC Hydro's forecast base operating cost increases. Two of these factors – storm restoration and the employer health tax[45] – are non-discretionary and are beyond BC Hydro's control. The third – Standard Labour Rate increases – is tied to the bargaining mandate for union staff provided to BC Hydro by the Public Sector Employers Council. To partially offset these increases, BC Hydro has achieved reductions in controllable costs through a variety of means, including vacancy factor savings, lease consolidations, and a reduction to advertising costs.
Taxes Chapter 8, Section 8.6 Appendix A, Schedule 6.0	23.6	Four factors are increasing the taxes paid by BC Hydro: increased assessed property values, the completion of new capital projects that are subject to taxation, increased grants-in-lieu due to an increase in forecast electricity sales and increases to provincial and municipal taxation rates.
Amortization Chapter 8, Section 8.2 Appendix A, Schedule 7.0	104.9	Two factors are driving increased amortization costs during the test period. First, BC Hydro's forecast capital additions have increased as a result of recent capital investments. Second, in 2018, the BCUC approved the 2017 Waneta Transaction. As discussed below, under Miscellaneous Revenues and Other, the Waneta 2017 Transaction is reducing BC Hydro's overall revenue requirements by increasing miscellaneous revenues to BC Hydro. Further information on our capital expenditures and additions are provided throughout Chapter 6 and further information on the Waneta 2017 Transaction is provided in Chapter 4, section 4.2.3.
Finance Charges Chapter 8, Section 8.5 Appendix A, Schedule 8.0	106.8	A credit balance in the Finance Charges Regulatory Account was refunded to ratepayers over the fiscal 2017 to fiscal 2019 period, which resulted in lower finance charges in fiscal 2019. In this application, forecast finance charges are increasing, primarily because this credit balance has now been returned to ratepayers and is no longer offsetting total finance charges in this test period. The other driver for the increase in finance charges is an increase to forecast borrowing costs, primarily due to recent capital expenditures. These increases more than offset a decrease in finance charges related to an increase in forecast interest during construction.

43 BC Hydro explains in Chapter 5, section 5.5.1 why base operating costs should be the focus.

44 BC Hydro uses the B.C. Consumer Price Index measure for the forecast rate of inflation. The forecast rate of inflation for fiscal 2019, fiscal 2020 and fiscal 2021 is 2.7 per cent, 2.3 per cent and 2.0 per cent, respectively.

45 The Employer Health Tax is partially offset by the elimination of Medical Services Plan premiums. As discussed in Chapter 7, section 7.8.11, the elimination of Medical Services Plan Premiums significantly reduced the balance in the Non-Current Pension Costs Regulatory Account.

Cost Component and References	Difference ($ million)	Explanation
Return on Equity Chapter 8, Section 8.3 Appendix A, Schedule 9.0	0	As part of the Comprehensive Review, the Government of B.C. is providing direction to the BCUC to help transition BC Hydro to increased regulation over time. Section 8 of Direction No. 8 states that the BCUC must set BC Hydro's Return on Equity at $712 million for fiscal 2020 and fiscal 2021. This amount is equal to the amount for fiscal 2019, which means that Return on Equity is not contributing to the proposed bill increase. For fiscal 2022 onwards, the BCUC will be able to determine BC Hydro's Return on Equity.
Miscellaneous Revenue Chapter 8, Section 8.7 Appendix A, Schedule 15.0	(103.1)	Miscellaneous revenues reduce overall revenue requirements and are planned to increase during the test period, primarily due to lease and other revenues related the Waneta 2017 Transaction which is discussed further in Chapter 4, section 4.2.3.
Inter-Segment Revenue Chapter 8, Section 8.8 Appendix A, Schedule 3.0	(7.2)	Inter-segment revenues are relatively consistent from fiscal 2019 RRA to fiscal 2021 plan.
Subsidiary Net Income Chapter 8, Section 8.9 Appendix A, Schedule 1.0	(69.6)	Subsidiary net income is increasing, primarily due to an increase in the five-year average that is used to forecast Trade Income[46] and because BC Hydro is requesting BCUC approval to refund the credit balance in the Trade Income Deferral Account to ratepayers. The Trade Income Deferral Account is used to capture variances between forecast and actual Trade Income and is discussed further in Chapter 7, section 7.7.1.
Other Utilities Revenue Chapter 8, Section 8.13.2 Appendix A, Schedule 14.0	(16.6)	The inclusion of Other Utilities Revenue in BC Hydro's revenue requirements reduces the overall revenue requirements. Other Utilities Revenue is increasing, primarily due to the adoption of IFRS 15 which impacts the accounting of payments made by Seattle City Light under the terms of the Skagit River Agreement.
Liquefied Natural Gas Revenue Chapter 2, Section 2.5.9 Appendix A, Schedule 14.0	10.9	In October 2018, the Government of B.C. removed a previous provision that prevented LNG customers from receiving service under BC Hydro's transmission rate schedules. This means that revenue from LNG customers is now recorded as general rate revenue and not as a separate line item.
Deferral Rider Revenue Chapter 7 Appendix A, Schedule 14.0	241.8	The decrease in DARR revenue reflects BC Hydro's request for BCUC approval to reduce the DARR from 5 per cent to 0 per cent on April 1, 2019.

1.8 This Application Balances Affordability and Reliability

The approvals that we are seeking in this application balance affordability and reliability to deliver value to our ratepayers. The following sections explain, at a high

[46] Trade Income is the greater of (a) the amount that is equal to BC Hydro's consolidated net income, less BC Hydro's non-consolidated net income, less the net income of BC Hydro's subsidiaries except Powerex, less the amount that BC Hydro's consolidated net income changes due to foreign currency translation gains and losses on intercompany balances between BC Hydro and Powerex; and (b) zero.

level, why the forecast revenue requirements in the test period represent reasonable costs to provide safe and reliable service to our customers.

1.8.1 Legal and Regulatory Framework Provides Guidance

Chapter 2 provides an overview of the legislation relevant to BC Hydro's revenue requirements as well as the specific regulations and policies that will inform the BCUC's consideration of the approvals that BC Hydro is seeking in this application. Chapter 2 is organized around the following key points:

- Section 2.2 explains that the Comprehensive Review has resulted in regulatory changes and plans to table legislative amendments that enhance the BCUC's oversight of BC Hydro generally and with respect to the review of this application.
- Section 2.3 explains how BC Hydro's powers and mandate under the *Hydro and Power Authority Act* remain unchanged.
- Section 2.4 describes how the *Utilities Commission Act* provides the BCUC with the ability to set BC Hydro's rates and to accept or reject the proposed DSM expenditure schedule. As a result of the changes from the Comprehensive Review, the BCUC's mandate in these areas with regards to BC Hydro is now similar to other regulated utilities in British Columbia.
- Section 2.5 identifies certain aspects of BC Hydro's revenue requirements that continue to be directed or guided by regulations issued under the *Utilities Commission Act*.
- Section 2.6 addresses the continued application of the *Clean Energy Act* to BC Hydro. The Act affects BC Hydro's Cost of Energy and DSM expenditures and requires the BCUC to allow BC Hydro to recover certain costs.
- Section 2.7 discusses BC Hydro's obligation to provide service to remote communities.

- Section 2.8 explains that BC Hydro is not proposing any changes to Standard Charges in this application.
- Section 2.9 provides a summary of the BCUC's legal authority with regards to the approvals that BC Hydro is seeking in this application.

The evidence provided in Chapter 2 is supported by the following appendices:

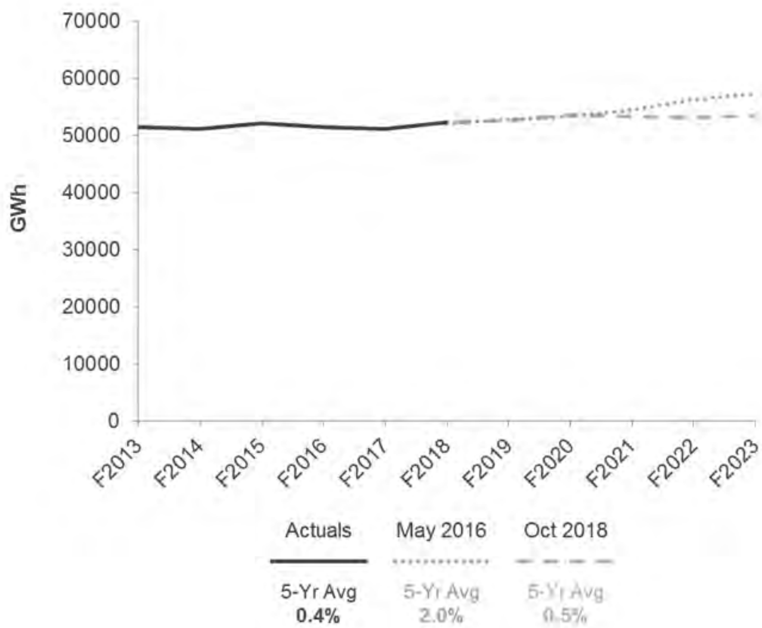
- Appendix B provides a Draft Order;
- Appendix C provides the report on the Comprehensive Review; and
- Appendix D provides copies of key regulations summarized in Chapter 2.

1.8.2 Our Load and Revenue Forecasts Are Reasonable

Chapter 3 provides our Load Forecast and associated Revenue Forecast. The forecasts for fiscal 2020 and fiscal 2021 are used in the calculation of the test period revenue requirements.

The Load Forecast was completed in October 2018. Overall, BC Hydro is forecasting a lower load growth rate relative to the May 2016 Load Forecast as contained in the Previous Application. This is shown in Figure 1-4 below.

Figure 1-4 Electricity Sales Summary – Oct 2018 Load Forecast vs. May 2016 Load Forecast[47]



Chapter 3 is organized around the following key points:

- Section 3.2 explains our load forecast methods, and the inputs used for each customer sector. We conclude that our methodology and inputs are the appropriate basis for the Load Forecast in this application considering:
  - The recent performance of our own methodology;
  - The endorsement of the methodology by an internal audit review conducted by an independent expert;
  - Improvements to our methodology, which address the audit recommendations and the issues raised by the BCUC;

[47] The graph shows a fiscal 2019 to fiscal 2023 compound growth rate using billed sales forecast after rates and after DSM savings

    - The Auditor General's recent determination that our methodology is robust and compares favourably with industry standards; and
    - The favourable performance of our methodology relative to an alternative short-term forecast methodology.
- Section 3.3 presents the results of the Load Forecast, both the mid forecast and the high and low uncertainty bands:
    - Demand for electricity is forecast to increase by approximately 650 GWh or 1.2 per cent from fiscal 2019 to fiscal 2021; and
    - The high and low band around the forecast is the product of Monte Carlo analysis, and illustrates the range of uncertainty.
- Section 3.4 explains our Revenue Forecast methodology, which is straightforward and unchanged from the methodology used in the Previous Application; and
- Section 3.5 presents the results of the Revenue Forecast by customer sector, based on the output of the improved load forecast methodology.

The evidence provided in Chapter 3 is supported by the following appendices:

- Appendix O provides BC Hydro's October 2018 Load Forecast and supporting documentation which is the source of the fiscal 2020 and fiscal 2021 Load Forecast provided in this application;
- Appendix P provides BC Hydro's internal audit on Load Forecasting; and
- Appendix Q provides an Elasticity Study completed by DNV GL. We have updated the price elasticity inputs to our Load Forecast based on this study.

1.8.3 Actions are Being Taken to Limit BC Hydro's Cost of Energy

Chapter 4 discusses BC Hydro's energy costs.

BC Hydro is not, as part of this application, proposing any generation projects or seeking acceptance of any EPAs. Rather, this chapter provides the necessary information to demonstrate that the forecast Cost of Energy is reasonable for the purpose of setting rates in the test period. While the forecast Cost of Energy is used in determining our total revenue requirements, customers ultimately only pay the actual Cost of Energy through the use of regulatory accounts.

Chapter 4 is organized around the following key points:

- Section 4.2 provides background information on how BC Hydro's Cost of Energy is categorized. In light of the elimination of the Heritage Contract, BC Hydro has restructured the presentation of the Cost of Energy in our revenue requirements model to improve clarity of the accounting treatment of our Cost of Energy.[48] The presentation change has no operational or financial impact.
- Section 4.3 describes BC Hydro's approach to managing future energy supply, which includes a number of steps to reduce IPP energy costs. This section also discusses the impacts of the Comprehensive Review on BC Hydro's Cost of Energy.
- Section 4.4, discusses how BC Hydro maximizes the expected value of its energy supply portfolio through its use of monthly Energy Studies. The

[48] The costs of Market Electricity Purchases, Surplus Sales, Net Purchases (Sales) from Powerex and Domestic Transmission - Export were previously distributed into Heritage and Non Heritage Energy costs, based on the Heritage Contract threshold of 49,000 GWh. As discussed in Chapter 2, section 2.2.1, as part of the Comprehensive Review, the Government of B.C. repealed Direction No. 7 to the BCUC, which included the Heritage Contract. The repeal of the Heritage Contract has no impact on BC Hydro or ratepayers; however, it provides BC Hydro with the flexibility to re-categorize its Cost of Energy for this application by creating a third category, Market Energy, which includes the four components – Market Electricity Purchases, Surplus Sales, Net Purchases (Sales) from Powerex and Domestic Transmission - Export.

methodology has been endorsed by independent experts as part of a recent audit.

- Section 4.5 provides BC Hydro's forecast Cost of Energy for the test period, and explains the treatment of variances between the forecast Cost of Energy and actual Cost of Energy.
- Sections 4.6, 4.7 and 4.8 provide a more detailed breakdown of the Cost of Energy by category (Heritage, Non-Heritage and Market). Overall, by fiscal 2021, BC Hydro's Cost of Energy is forecast to increase by $157 million from the fiscal 2019 RRA amount. This forecast increase is primarily driven by an increase in costs related to IPPs and Long-Term Commitments. These forecast costs are primarily associated with existing EPAs, and because the terms of these agreements are already set, the forecast costs for these EPAs are largely prescribed. With few exceptions, BC Hydro is not acquiring new resources from IPPs and those exceptions represent only a very small portion of the forecast Cost of Energy.

The evidence provided in Chapter 4 is supported by the following appendix:

- Appendix DD provides BC Hydro's internal audit on the Energy Studies process.

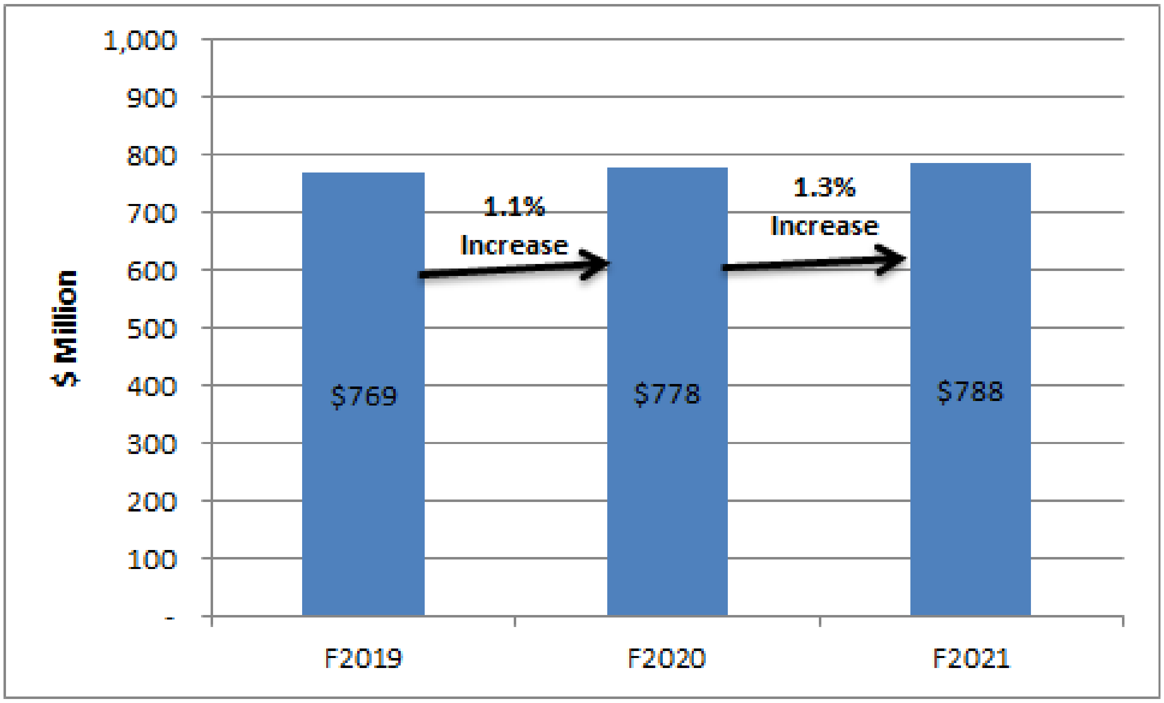
1.8.4 Despite Increases in Uncontrollable Costs, We Have Held Our Base Operating Cost Increases Below Inflation by Reducing Controllable Costs

Chapter 5 describes our planned operating costs and FTEs for the test period. As shown in Figure 1-5 below, BC Hydro is limiting base operating cost increases[49] below the forecast rate of inflation[50] over the test period.

[49] BC Hydro explains in Chapter 5, section 5.5.1 why base operating costs should be the focus.

[50] BC Hydro uses the B.C. Consumer Price Index measure for the forecast rate of inflation. The forecast rate of inflation for fiscal 2019, fiscal 2020 and fiscal 2021 is 2.7 per cent, 2.3 per cent and 2.0 per cent, respectively.

Figure 1-5 Base Operating Cost Increases Are Below Forecast Inflation



BC Hydro has been able to limit base operating cost increases to below the forecast rate of inflation for the test period by partially offsetting non-controllable cost increases with reductions to controllable costs.

Detailed support for BC Hydro's forecast operating costs, by Business Group, are provided in Chapters 5A through 5G. In response to commentary from the BCUC about needing to better understand BC Hydro's operating cost budget, these chapters provide significantly more information than the Previous Application on the operating costs and FTEs for each of BC Hydro's six business groups and 39 KBUs. The composition of the entire budget of each KBU, not just the incremental costs, is addressed in these Chapters.

Chapter 5 is organized around the following key points:

- Section 5.2 summarizes how BC Hydro has considered and responded to the BCUC's comments and recommendations about BC Hydro's operating costs in its Decision;[51]
- Section 5.3 describes changes to BC Hydro's organizational structure since the Previous Application. We have completed the transition to a centralized and functionally-aligned structure;
- Section 5.4 explains that BC Hydro has a robust budgeting process, with both top-down and bottom-up elements;
- Section 5.5 provides an overview of BC Hydro's operating costs during the test period:
  - ▶ Controllable cost pressures were absorbed within existing budgets, which means that after accounting for Standard Labour Rate increases, most KBUs were held to their current level of spend; [52] and
  - ▶ BC Hydro has achieved reductions in controllable costs through a variety of means, including vacancy factor savings, lease consolidations, and a reduction to advertising costs.
- Section 5.6 provides an overview of BC Hydro's FTEs and Standard Labour Rates:
  - ▶ The Workforce Optimization Program has reduced BC Hydro's total labour costs by replacing contractors with internal employees;
  - ▶ The repatriation of services previously provided by Accenture has resulted in higher than expected cost savings;

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[51] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 33.

[52] Operating costs for some KBUs may increase or decrease from fiscal 2019 forecast to fiscal 2020 plan, due to budget transfers related to re-organizations. Overall, these transfers are cost neutral.

    - Apart from growth in the workforce directly related to increased capital investment, BC Hydro's FTEs have remained relatively flat since fiscal 2012 and will remain flat during the test period; and
    - A 2017 assessment by Morneau Shepell concluded that on a total cash basis, BC Hydro's employee compensation is 11 per cent below median market rates. After factoring in the value of pension benefits and time off programs, employee compensation is comparable to median market rates.
- Section 5.7 addresses benchmarking:
    - A report prepared by The Brattle Group shows that BC Hydro's operating costs[53] benchmark favourably against a peer group of U.S. utilities;
    - An internal analysis provides an indicative assessment that BC Hydro's operating costs compare well against those of other major Canadian utilities;
    - Recent benchmarking on maintenance delivery costs has demonstrated that BC Hydro's costs are consistent with or better than its utility peers; and
    - Cost benchmarking and metrics are used in other areas of the business.
- Section 5.8 explains how BC Hydro is optimizing the level of Power System maintenance, successfully mitigating increases in maintenance expenditures in recent years despite a growing Power System asset base, aging assets, and increased regulatory requirements.
- Section 5.9 outlines the content of Chapters 5A to 5G, which provide the composition, drivers and outcomes of each KBU budget in more detail than in the Previous Application.

[53] The Brattle Benchmarking Study focused on operations and maintenance costs, excluding the costs of fuel and water rental that are used in the power production process. The Brattle Benchmarking Study refers to these costs as "non-fuel operations and maintenance expenses", or by the acronym "NFOM". The costs of fuel and water rentals that are used in the power production process are excluded because they are reflected in BC Hydro's cost of energy. Cost of Energy is addressed in Chapter 4 of the Application.

The evidence provided in Chapter 5 and Chapters 5A to 5G is supported by the following appendices:

- Appendix R provides BC Hydro's Organization Chart;
- Appendix S provides a Summary of Organization Changes since our Previous Application;
- Appendix T provides the Brattle Benchmarking Study; and
- Appendix U provides the data used for BC Hydro's internal analysis of operating costs other major Canadian utilities.

1.8.5 Capital Expenditures and Additions Are Required for a Safe, Reliable System

Chapter 6 explains BC Hydro's capital planning and delivery processes as well as our planned capital expenditures and additions in fiscal 2020 and fiscal 2021. Capital "additions" are the capital investments that are affecting rates during the test period, which occurs when projects enter service. Capital "expenditures" represent spending incurred during the test period that will not affect rates until the project goes in service.

The capital forecasts in Chapter 6 are derived from the fiscal 2020 to fiscal 2024 Capital Plan (**Capital Plan**) that BC Hydro finalized in October 2018. The Capital Plan supported the Comprehensive Review and contains investment-level detail for fiscal 2020 to fiscal 2024, and a high-level investment projection for fiscal 2025 to fiscal 2029.

Planned capital expenditures and additions in fiscal 2020 and fiscal 2021 are lower than the fiscal 2017 to fiscal 2019[54] test period due to the completion of major projects such as the John Hart Generating Station Replacement project.

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54 Based on average annual amounts and excluding the Site C Project and BC Hydro's acquisition of Teck Resources Ltd.'s two-thirds interest in the Waneta generation facility.

Chapter 6 is organized around the following key points:

- Section 6.2 explains how the information provided in this application is aligned with BC Hydro's Revised Proposal filed on June 13, 2018 in the Capital Expenditures and Projects Review proceeding. It also identifies how BC Hydro has responded to the BCUC's Decision on our Previous Application;
- Section 6.3 describes our four-step Enterprise Capital Planning Process which appropriately balances affordability and system performance, and explains how this process was applied to create the Capital Plan that forms the basis of the capital investment information in this application;
- Section 6.4 describes how our Power System capital investments, which includes Generation, Transmission and Distribution Assets, are appropriately planned, delivered and forecast for the test period. The section describes the nature of the assets, the bottom-up planning processes, the delivery processes, and provides the forecast capital expenditures and additions; and
- Sections 6.5 through 6.9 describe our Technology, Properties, Fleet and Business Support and other capital investments including the nature of these investments and how they are appropriately planned, delivered and forecast for the test period.

The evidence provided in Chapter 6 is supported by the following appendices:

- Appendix F provides the Office of the Auditor General of B.C. Report, titled *Independent Audit of Capital Asset Management in BC Hydro*;
- Appendix H provides BC Hydro's Capital Plan with an outline of major investments, related risks, and opportunities;
- Appendix I provides capital investment information for projects that are greater than $2 million for technology or greater than $5 million for other projects with planned capital expenditures or additions in the test period;

- Appendix J provides capital project descriptions for 53 projects and programs of projects with planned total capital expenditures greater than $20 million with planned capital expenditures or additions in the test period;
- Appendix K provides summaries of Strategies, Plans, and Studies;
- Appendix L provides BC Hydro's Technology Strategy and Five-Year Plan;
- Appendix M provides asset health indices for BC Hydro's generation assets; and
- Appendix N provides asset health indices for BC Hydro's transmission and distribution assets.

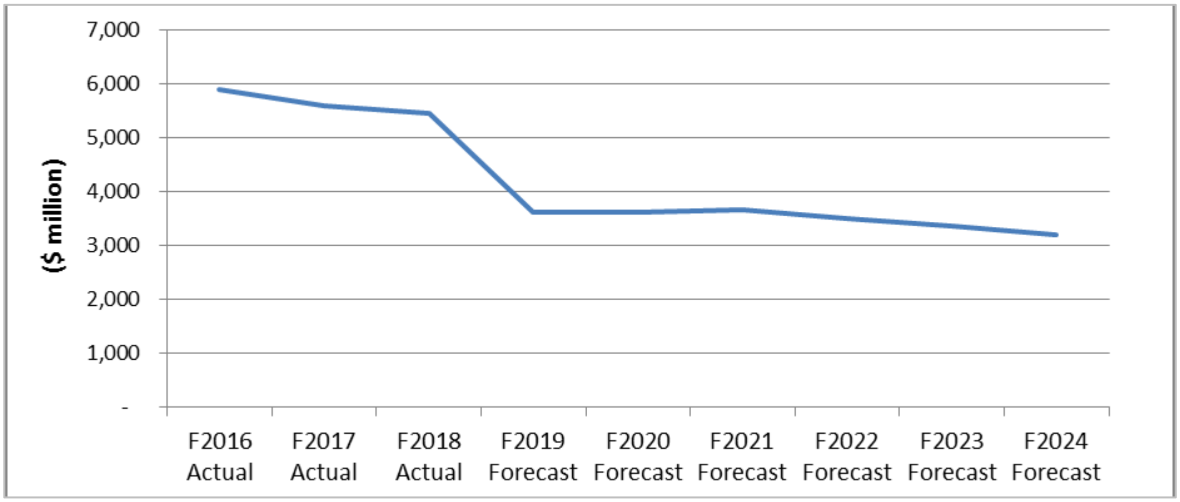
1.8.6 Our Use of Regulatory Accounts is Consistent with Accounting Standards and BCUC Guidelines

Chapter 7 describes BC Hydro's deferral and regulatory accounts (collectively referred to as regulatory accounts) and our proposals to change or close those accounts. BC Hydro is not requesting approval of any new regulatory accounts in this application.

BC Hydro's use of regulatory accounts is in accordance with International Financial Reporting Standards (**IFRS**) and in compliance with BCUC Orders and government directions. Rate-regulated accounting is permitted under International Financial Reporting Standard 14, *Regulatory Deferral Accounts* (**IFRS 14**).

As shown in Figure 1-6 below, BC Hydro has had three successive years of declining regulatory account balances.

Figure 1-6 Regulatory Account Balances
Fiscal 2016 to Fiscal 2018 Actual and
Fiscal 2019 to Fiscal 2024 Forecast



As shown in Figure 1-6 above, BC Hydro's total net regulatory account balance peaked at $5.9 billion in fiscal 2016 and is forecast to be reduced to $3.6 billion at the end of fiscal 2019 (a reduction of $2.3 billion or 39 per cent) and to $3.2 billion at the end of fiscal 2024.

Chapter 7 is organized around the following key points:

- Section 7.2 explains that the Comprehensive Review has responded to concerns raised by the Auditor General by enhancing the BCUC's oversight of BC Hydro.
- Section 7.3 presents our approach to managing regulatory account balances over the next five years. It shows the actual and forecast closing account balances of the regulatory accounts by year from fiscal 2017 to fiscal 2024. Based on the requests in this application, the total balance in the regulatory accounts is expected to decline by approximately $2.3 billion from fiscal 2018 to fiscal 2024.
- Section 7.4 explains that BC Hydro's use of regulatory accounts is in accordance with IFRS.

- Section 7.5 explains that the types of regulatory accounts used by BC Hydro are consistent with those in the BCUC Regulatory Account Filing Checklist,[55] and outlines considerations to set appropriate mechanisms to ensure the balances in our regulatory accounts are recovered over the appropriate time period.
- Section 7.6 outlines criteria for evaluating the establishment of new regulatory accounts.
- Section 7.7 describes the existing regulatory accounts where BC Hydro is requesting changes, outlines the reasons for each request, and provides a description of each regulatory account for context.
- Section 7.8 explains that BC Hydro is not requesting changes to most of its existing regulatory accounts, and provides a description of each unchanged regulatory account for context.
- Section 7.9 explains that BC Hydro applies interest to several regulatory accounts at BC Hydro's weighted average cost of debt in recognition of the carrying costs incurred by BC Hydro.
- Section 7.10 provides a high-level summary of the information in this chapter for each of BC Hydro's regulatory accounts.

1.8.7 Other Revenue Requirements Items

Chapter 8 describes the other revenue requirements items, including amortization expense, return on equity, capital structure, finance charges, taxes, miscellaneous and inter-segment revenues, subsidiary net income, the allocation of BC Hydro's business support costs, and provisions and other. This Chapter also explains accounting changes required due to the full adoption of IFRS in fiscal 2019.

55 https://www.bcuc.com/Documents/Guidelines/2017/05-03-2017_RegulatoryAccountFilingChecklist.pdf

1.8.8 Transmission Revenue Requirements

Chapter 9 describes how BC Hydro's proposed Open Access Transmission Tariff (**OATT**) rates are determined to recover BC Hydro's Transmission Revenue Requirement (**TRR**) consistent with past Orders of the BCUC. The rates charged under the OATT are for Network Integration Transmission Service (**NITS**), Point-To-Point (**PTP**) Transmission Service and Ancillary Services. As the main users of the transmission system, BC Hydro and Powerex account for approximately 98.5 per cent of the revenue collected through the OATT. External transmission customers account for the remaining approximately 1.5 per cent of revenue.

1.8.9 Our Proposed DSM Expenditures Provide Broad Access and Limit Forecast Rate Increases

Chapter 10 sets out the information and analysis in support of our proposed fiscal 2020 to fiscal 2021 demand-side measures expenditure schedule. We are requesting that the BCUC accept this schedule under section 44.2 of the *Utilities Commission Act*.

The proposed expenditure schedule includes expenditures on demand-side measures that we anticipate making over the fiscal 2020 to fiscal 2021 test period. This includes expenditures on the thermo-mechanical pulp program.[56] In addition to the proposed schedule, BC Hydro anticipates expenditures on low-carbon electrification prescribed undertakings over the same period.[57] All of these expenditures will help customers manage their energy use.

[56] Expenditures for the Thermo-Mechanical Pulp program are shown separately, since the costs of this program are covered by the Direction to the British Columbia Utilities Commission Respecting the Authority's TMP Program (B.C. Reg. 139/2015). A copy is provided in Appendix D.

[57] Expenditures for the low-carbon electrification initiatives are shown separately, since the costs of these initiatives are covered by the Direction to the British Columbia Utilities Commission Respecting Undertaking Costs (OIC 100/2017) and the Greenhouse Gas Reduction (Clean Energy) Regulation (B.C. Reg. 102/2012) as amended by OIC 101/2017. In this application, BC Hydro is requesting confirmation of the deferral treatment of low-carbon electrification expenditures in Chapter 2, section 2.8. A copy of the low-carbon electrification directions are provided in Appendix D.

Our request responds to the BCUC's Decision on our Previous Application by increasing expenditures for the residential sector by approximately 50 per cent and providing a new program for customers in Non-Integrated Areas, while staying within the overall portfolio spending envelope. It also continues our moderation approach, providing broad customer access to conservation and energy management opportunities while managing the overall level of expenditures to limit forecast rate increases while BC Hydro is in an energy surplus.

The expenditures associated with each of these initiatives are shown in Table 1-7 below.

Table 1-7 Fiscal 2020 to Fiscal 2021 Demand-Side Measures Expenditure Schedule and Low-Carbon Electrification Expenditures

	Expenditure ($ million)
Fiscal 2020 Demand-Side Measures	90.8
Fiscal 2021 Demand-Side Measures	89.1
Thermo-Mechanical Pulp (Fiscal 2020-Fiscal 2021)	27.2[58]
Two-Year Total (for section 44.2 acceptance)	**207.1**
Low-Carbon Electrification (Fiscal 2020-Fiscal 2021)	28.0
Two-Year Total (including Low-Carbon Electrification)	**235.1**

Chapter 10 is organized around the following key points:

- Section 10.2 reviews the outcomes of the fiscal 2017 to fiscal 2019 DSM initiatives and low-carbon electrification undertakings and BC Hydro's response to directives from the Previous Application.
- Section 10.3 explains that BC Hydro is complying with the regulatory and legislative framework applicable to BC Hydro's traditional DSM and low-carbon electrification expenditures.

[58] All expenditures related to Thermo-Mechanical Pulp are forecasted to occur in fiscal 2021.

- Section 10.4 presents BC Hydro's approach for determining the level of expenditures during the test period.
- Section 10.5 presents an overview of BC Hydro's expenditures over the test period, the anticipated energy and capacity impacts as well as the cost-effectiveness and other benefits of the plan. This section also sets out BC Hydro's request to revise the approach to allocating portfolio-level costs to programs, provides evidence on the persistence of DSM savings and describes how BC Hydro has re-categorized its energy management activities into a new program called Energy Management Activities within each sector.
- Section 10.6 demonstrates that BC Hydro manages the performance of the plan in a comprehensive manner, including tracking a number of performance metrics and regular management oversight and reporting.

The evidence provided in Chapter 10 is supported by the following appendices:

- Appendix X provides BC Hydro's Fiscal 2020 to Fiscal 2022 DSM Business Plan.
- Appendix Y provides information on BC Hydro's Fiscal 2019 to Fiscal 2021 Low Carbon Electrification Program.
- Appendix Z provides our Annual DSM Reports to the BCUC.
- Appendix AA provides our Annual DSM Measurement, Verification and Evaluation Reports to the BCUC.
- Appendix BB provides our Greenhouse Gas Reduction Regulation Annual Reports.
- Appendix CC provides the Codes and Standards Attribution Report completed by the Cadmus Group.

1.9 Benchmarking and Audits Indicate that BC Hydro is Well Managed and Revenue Requirements Are Reasonable

Throughout this application, BC Hydro has referenced external studies and independent expertise which indicate that our costs are reasonable and that our operations are well-managed. We have also identified recommendations and opportunities for improvement, where applicable.

External studies and reports referenced throughout this application are summarized below. In a number of cases, these studies were commissioned by BC Hydro's Audit Services department, which is discussed further in Chapter 5E, section 5E.4.1.4. Independent subject matter experts are engaged by Audit Services when expertise is required on the audit subject. A summary of all audits conducted by the Audit Services department from fiscal 2017 to fiscal 2019 to-date is provided in Appendix HH.

- ***Operating costs benchmark favourably*** - A 2019 independent report prepared by The Brattle Group for this proceeding, led by Principal William P. Zarakas, found that BC Hydro's operating costs benchmark favourably against a peer group of U.S. utilities. This benchmarking study is provided as Appendix T.
- ***Maintenance costs are consistent with or better than utility peers*** - BC Hydro regularly commissions independent benchmarking on maintenance delivery costs from Navigant and First Quartile, both of which are experts in this field. Recent results have demonstrated that BC Hydro's maintenance costs are consistent with or better than its utility peers. Further information is provided in Chapter 5, section 5.8.
- ***Compensation is below median market rates*** - Compensation benchmarking performed by Morneau Shepell in 2017 concluded that on an average total cash basis, BC Hydro employees earn 11 per cent less than median market rates.

After factoring in the value of pension benefits and time off programs, BC Hydro's compensation package is comparable, at 2 per cent below median market rates. Further information is provided in Chapter 5, section 5.6.5.

- ***Project management practices are strong*** - In 2016, BC Hydro completed its second Organizational Project Management Maturity Model Assessment and placed in the top-tier of participating organizations from around the world. Also in 2016, BC Hydro also received the Project Management Office of the Year Award from the Project Management Institute, recognizing superior organizational project management capabilities. Further information is provided in Chapter 6, section 6.2.1.1.
- ***Asset management practices are strong*** - In December 2018, the Office of the Auditor General of B.C. released an independent audit of Capital Asset Management in BC Hydro. The audit found that BC Hydro has good asset management practices as a result of a decade-long plan and associated efforts and did not identify any recommendations. This audit is provided as Appendix F.
- ***DSM processes and controls are in place -*** In fiscal 2017, BC Hydro's Audit Services department engaged experts from GDS Canada Consulting Ltd., with over 40 years of experience in market evaluations and managing energy efficiency programs, to help assess whether effective processes and controls were in place for our DSM activities and programs. The internal audit found that processes and controls are in place for planning, program development, implementation and evaluation. Recommendations included simplifying the planning process, documentation of assumptions and processes and developing a central assumptions database. Further information on our DSM processes and controls is provided in Chapter 10, section 10.6.
- ***Progress has been made on Disaster Preparedness -*** In fiscal 2017, BC Hydro's Audit Services department engaged PricewaterhouseCoopers'

business resilience practice to help assess BC Hydro's plans and ability to respond to and recover from, a catastrophic disruption of business operations. The internal audit found that an effective governance structure and framework has been formulated but not fully implemented. Emergency management plans, exercise and training programs are in place but efforts in enterprise-wide business impact analysis, business continuity, information technology disaster recovery and corrective action plans require further enhancement. While this internal audit indicates that further work is required, it demonstrates significant progress since BC Hydro's initial internal audit on disaster preparedness in fiscal 2013. Further information is provided in Chapter 5D, section 5D. 7.

- ***Load forecasting methodologies are consistent with best practices -*** In fiscal 2018, BC Hydro's Audit Services department engaged experts from GDS Associates Inc., with over 30 years of load forecasting experience, to help review BC Hydro's load forecasting process to ensure timely and reliable energy and peak demand forecasts to support operational, financial and strategic planning. The internal audit found that BC Hydro's load forecasting function compares favourably to industry standards and to other large electric utilities in North America and that load forecasting methodologies are consistent with best practices. This audit is provided as Appendix P.
- ***Dam Safety Program is consistent with international practices and in some aspects is at best practice levels -*** In fiscal 2019, BC Hydro's Audit Services department engaged a Commissioner for Dam Safety from the Swiss Federal Office of Energy and a Professional Engineer at Health and Safety Executive, the statutory regulator of occupational health and safety in Great Britain. These experts helped to review whether dam safety risks are identified, prioritized and managed to ensure the objectives of BC Hydro's Dam Safety Program are achieved. The internal audit found that BC Hydro has a well-established Dam Safety Program that is in line with international practices with some aspects operating at best practice levels. Governance is effective

with appropriate oversight and the relationship with the regulator is strong and forthcoming. A robust risk assessment process continues to drive key dam safety activities and operational activities are executed to monitor dams. Further information on BC Hydro's Dam Safety Program is provided in Chapter 5A, section 5A.5 and Chapter 6, section 6.4.2.2.

- ***Smart Metering System is delivering intended services with appropriate controls -*** In fiscal 2019, BC Hydro's Audit Services department engaged experts from Bridge Energy Group with extensive experience in technology strategy, enterprise architecture, integration and utility security to assess whether the Smart Metering system is fully operationalized, managed and functioning effectively. The internal audit found that the Smart Metering System is delivering intended services to stakeholders with controls around data and application security, access and privacy. Operations are effectively governed and the system is well monitored. Further information on the benefits of BC Hydro's Smart Metering System is provided in Chapter 5E, section 5E.5.2.5.
- ***Energy Studies methodology is consistent with leading practices*** - In fiscal 2019, BC Hydro's Audit Services department engaged experts from SINTEF, an independent research organization that conducts contract research and development projects. These experts specialized in load forecasting, risk management, hydrothermal market modelling and hydropower scheduling models. The internal audit found that BC Hydro has a well-established Energy Studies process in place, that key models are appropriate and that the methodologies applied are in line with leading industry practices. This audit is provided as Appendix DD.

1.10 Proposed Regulatory Process

This section sets out a proposed regulatory process for this application. The proposed process reflects our belief that an open and transparent relationship with the BCUC and interveners in regulatory proceedings leads to better decisions and improved outcomes for our customers.

1.10.1 BC Hydro Will Continue With the Pragmatic and Transparent Approach Used in the Previous Proceeding

In the proceeding for our Previous Application, BC Hydro adopted a pragmatic and transparent approach to providing evidence and answering information requests. The BCUC noted the high quality and depth of the evidence on the record and recognized BC Hydro's pragmatic approach.[59] BC Hydro is adopting the same pragmatic and transparent approach in this proceeding.

1.10.2 Proposed Initial Timetable Reflects Input of Interveners

Table 1-8 below sets out a proposed initial regulatory review process for this application. From October 2018 to December 2018, BC Hydro consulted with some potential interveners[60] on a proposed regulatory process for this application. The timetable provided below reflects the input that BC Hydro received.

The proposed initial timetable contemplates two rounds of information requests, followed by the first Procedural Conference to determine the remaining steps in the proceeding.

We believe that it makes sense to hold the procedural conference after two rounds of information requests, rather than immediately following the filing of the Application. The typical reasons for holding a Procedural Conference prior to the first round of information requests are absent in this instance. Specifically:

[59] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Exhibit A-18, Reasons for Decision for Order No. G-7-17, pages 7 to 8.

[60] BC Hydro met with AMPC, BCSEA, CEBC, MoveUp and Zone II Ratepayers.

- An early Procedural Conference is typically held to determine how many rounds of information requests there will be (i.e., one or two). In this case, BC Hydro is proposing two rounds of information requests, not one.
- An early Procedural Conference is typically held to determine the scope of issues for the Application. In this case, given our commitment to take a pragmatic and transparent approach when answering information requests, we believe that a Procedural Conference to determine the scope of the Application is not required. Provided that information requests are proper and relevant to matters that affect the test period revenue requirements, BC Hydro anticipates being able to provide answers. We believe it would be more efficient to address issues on specific questions in writing, if and when they arise.

BC Hydro recommends that a Procedural Conference be held after responses to Round 2 Information Requests are received and reviewed by the BCUC and interveners. The purpose of this Procedural Conference would be to determine further process. We submit that this approach is efficient and is fair to all parties.

Table 1-8 Proposed Regulatory Review Process

Process	Date
Registration of Interveners and Interested Parties	March 14, 2019
BC Hydro Workshop No. 1	March 15, 2019
BCUC Information Request No.1 to BC Hydro	April 2, 2019
Intervener Information Request No. 1 to BC Hydro	April 11, 2019
BC Hydro responds BCUC and Intervener Information Request No. 1	May 16, 2019
BCUC Information Request No. 2	June 11, 2019
Intervener Information Request No. 2	June 20, 2019
BC Hydro responds to BCUC and Intervener Information Request No. 2	July 18, 2019
Procedural Conference	August 1, 2019

1.11 Communications

Communications regarding this application should be directed to:

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Fiscal 2020 to Fiscal 2021

Revenue Requirements Application

Chapter 2

Legal and Regulatory Framework

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2.1 Chapter Overview

This chapter provides an overview of the legislation relevant to BC Hydro's revenue requirements as well as the specific regulations and policies that will inform the BCUC's consideration of the approvals that BC Hydro is seeking in this application. This Chapter is organized around the following key points:

- Section 2.2 explains that the Comprehensive Review has resulted in regulatory changes and plans to table legislative amendments that enhance the BCUC's oversight of BC Hydro generally and with respect to the review of this application.
- Section 2.3 explains how BC Hydro's powers and mandate under the *Hydro and Power Authority Act* remain unchanged.
- Section 2.4 describes how the *Utilities Commission Act* provides the BCUC with the ability to set BC Hydro's rates and to accept or reject the proposed DSM expenditure schedule. As a result of the changes from the Comprehensive Review, the BCUC's mandate in these areas with regards to BC Hydro is now similar to other regulated utilities in British Columbia.
- Section 2.5 identifies certain aspects of BC Hydro's revenue requirements that continue to be directed or guided by regulations issued under the *Utilities Commission Act*.
- Section 2.6 addresses the continued application of the *Clean Energy Act* to BC Hydro. The Act affects BC Hydro's cost of energy and DSM expenditures and requires the BCUC to allow BC Hydro to recover certain costs.
- Section 2.7 discusses BC Hydro's obligation to provide service to remote communities.

- Section 2.8 explains that BC Hydro is not proposing any changes to Standard Charges in this application.
- Section 2.9 provides a summary of the BCUC's legal authority with regards to the approvals that BC Hydro is seeking in this application.

2.2 BCUC Oversight Has Been Enhanced

In June 2018, the Government of B.C. initiated the Comprehensive Review. Further information on this review is provided in Chapter 1, section 1.4 and the report on the review is provided in Appendix C. Phase One of this review resulted in changes to the regulations applicable to BC Hydro, which have enhanced the BCUC's oversight of this application. As noted in the report provided in Appendix C, the Government of B.C. also plans to table legislative amendments that will further update BC Hydro's regulatory framework. This section provides an overview of these changes and identifies their specific impact on this application.

2.2.1 Government Has Repealed Limiting Directions

As a result of the Comprehensive Review, the Government of B.C. repealed Directions No. 3, 6 and 7 to the BCUC. These repeals mean that most of the matters considered in this application are now subject to full review and oversight by the BCUC.

The Government of B.C. also repealed part of the Government Organization Accounting Standards Regulation (B.C. Reg. 257/2010) under the *Budget Transparency and Accountability Act*. BC Hydro has subsequently adopted International Financial Reporting Standards (IFRS) as of its fiscal 2019 year-end statements.

Lastly, the Government of B.C. issued Direction No. 8 to the BCUC which continues to provide direction to the BCUC in specific areas previously covered by Direction No. 7. These directions are intended to:

- Help transition BC Hydro to enhanced regulation over time;
- Provide interim direction ahead of proposed legislative amendments that are expected to be tabled in the B.C. Legislature this spring; and
- Continue to allow BC Hydro to recover costs related to previous policy decisions by the Government of B.C.

Table 2-1 below summarizes the areas that are now subject to enhanced BCUC oversight as a result of these repeals and identifies their specific impact on this application. It also identifies where Direction No. 8 continues to provide direction to the BCUC.

Table 2-1 Resulting BCUC Oversight from the Repeal of Directions No. 3, 6 and 7

Direction Repealed	Purpose of Direction	Impact on this Application
Repeal of Direction Nos. 3 and 6		
Direction No. 3	This Direction relates to BC Hydro's Fiscal 2012 to Fiscal 2014 Revenue Requirements Application and most of its directives are no longer applicable. Section 3 (2) had provided direction to the BCUC with regards to the amortization periods of the IFRS transition regulatory accounts and the Capital Project Investigation Costs Regulatory Account. By Order No. G-77-12A, the BCUC approved the amortization periods for these accounts, as directed. Section 3 (2) also directed the BCUC to allow BC Hydro to transition the overhead costs that can no longer be capitalized under IFRS into rates over a ten-year period.	As discussed in Chapter 7, sections 7.8.20 and 7.8.21, BC Hydro believes that the existing amortization periods for the two IFRS Transition regulatory accounts continue to be appropriate. As discussed in Chapter 7, section 7.7.5, the balance in the Capital Project Investigations Costs Regulatory Account will be fully amortized by the end of this test period. Accordingly, in this application, BC Hydro is requesting BCUC approval to close this account at the end of fiscal 2021. As discussed in Chapter 5G section 5G.8.1, ineligible capitalized overhead costs will be fully transitioned into rates by fiscal 2022.
Direction No. 6	This Direction relates to BC Hydro's Fiscal 2015 to Fiscal 2016 Revenue Requirements Application and its directives are no longer applicable.	None.
Repeal of Direction No. 7		
Sections 1, 2 (Definitions and Application)	Section 1 contains definitions and Section 2 states that the direction is issued under Section 3 of the *Utilities Commission Act*.	None.
Section 3 (Designing rates for transmission rate customers)	This section had provided direction to the BCUC on rate design for transmission service rate customers. It prevented the BCUC from reviewing Tariff Supplement Nos 5 and 6. Tariff Supplement No. 5 sets out terms and conditions under which BC Hydro will provide electricity to its customers receiving service at transmission voltage. Tariff Supplement 6 stipulates the terms, conditions and cost allocation for the construction of BC Hydro and private transmission facilities required to serve new load.	None. These issues will be addressed through individual rate design application proceedings.

Direction Repealed	Purpose of Direction	Impact on this Application
Section 4 (Net Income)	This section had required the BCUC to set BC Hydro's Return on Equity at $712 million for fiscal 2019 and subsequent years.	Section 3 of Direction No. 8 provides direction in this area to help transition BC Hydro to increased enhanced regulation over time. It states that the BCUC must set BC Hydro's Return on Equity at $712 million for fiscal 2020 and fiscal 2021. For fiscal 2022 onwards, the BCUC will be able to determine BC Hydro's Return on Equity. In the Comprehensive Review Report, the Government of B.C. indicated that it may provide policy guidance to the BCUC to inform this process.
Section 5 (a) and (b) (Heritage Contract)	These sections directed the BCUC to consider the Heritage Contract and to determine the energy required by BC Hydro to meet its domestic service obligations and the cost to BC Hydro of the portion of that required energy that is in excess of the energy supplied under the Heritage Contract. As explained by BC Hydro in our April 27, 2018 compliance filing in the Fiscal 2017 to Fiscal F2019 Revenue Requirements Application proceeding and Chapter 4, section 4.2 of this application, the Heritage Contract had no impact on BC Hydro's planning and operations or on how BC Hydro's cost of energy and rates are determined.	As discussed in Chapter 4, section 4.2, the repeal of the Heritage Contract has no impact on our planning and operations. However, it does provide BC Hydro with the flexibility to categorize its costs of energy differently for presentation purposes in the revenue requirements model for this application. In this application, Costs of Energy are categorized as Heritage Energy, Non-Heritage Energy or Market Energy. These categories are for presentation purposes only and are intended to provide better clarity of the accounting treatment of our Costs of Energy.
Section 5 (c) and (d) (Performance Based Regulation) (**PBR**)	These sections duplicated the authority already provided to the BCUC under section 60 (b.1) of the *Utilities Commission Act*, which allows the BCUC to set BC Hydro's rates through a mechanism such as PBR.	This application is being submitted on a cost of service basis. In response to Directive 28 of the BCUC's Decision on the Previous Application, BC Hydro has included a report on PBR as Chapter 11 of this application.

Direction Repealed	Purpose of Direction	Impact on this Application
Section 6 (Powerex Net Income)	This section required a loss from BC Hydro's electricity trading subsidiary, Powerex, to be borne by the shareholder, not BC Hydro's ratepayers.	As explained in Chapter 8, section 8.9, BC Hydro believes that it continues to be appropriate for Powerex's forecast net income to be included in BC Hydro's revenue requirements and that if Powerex incurs a loss, it should be borne by the shareholder. Powerex's net income continues to be forecast based on the historical five year average, and variances between actual net income and forecast net income are captured by the Trade Income Deferral Account. If Powerex's actual net income in a given year were to be less than $0, BC Hydro would only transfer the variance between forecast net income and $0 to the Trade Income Deferral Account.
Section 7 (a), (b) and (c) (Energy Variance Accounts)	These sections directed the BCUC to continue to allow certain variances to be deferred to the Heritage Deferral Account, the Non-Heritage Deferral Account and the Trade Income Deferral Account. Section 7 (c) also required costs associated with the decommissioning of portions of Burrard Thermal not required for transmission support services to be deferred to the Non-Heritage Deferral Account.	As explained in Chapter 7, section 7.7.1, BC Hydro believes that the variances captured by the Heritage Deferral Account, Non-Heritage Deferral Account and Trade Income Deferral Account continue to be appropriate.
Section 7 (d) (Demand Side Management Regulatory Account)	This section provided direction to the BCUC on the scope and amortization period of the Demand Side Management Regulatory Account.	As discussed in Chapter 10, section 10.5.6, BC Hydro believes that the scope and amortization period for the Demand Side Management Regulatory Account continue to be appropriate.

Direction Repealed	Purpose of Direction	Impact on this Application
Section 7 (e) (Rock Bay Remediation Regulatory Account)	This section directed the BCUC to allow Rock Bay remediation costs to be deferred.	As discussed in Chapter 7, section 7.8.4, the existing credit balance in the Rock Bay Remediation Regulatory Account will be returned to ratepayers over this test period. Remediation of the Rock Bay property was completed in fiscal 2019 and BC Hydro is not forecasting the deferral of any further remediation expenditures to this account over the test period. However, there may be minor differences between fiscal 2019 forecast and actual remediation costs and forecast and actual interest applied to this account over the test period. BC Hydro believes it continues to be appropriate to defer these variances to the Rock Bay Remediation Regulatory Account.
Section 7 (f) (Remediation Regulatory Account)	This section directed the BCUC to allow asbestos remediation cost variances to be deferred.	As discussed in Chapter 7, section 7.8.6, BC Hydro believes that it continues to be appropriate to defer the variances between actual and forecast asbestos remediation costs to the Remediation Regulatory Account.
Section 7 (g) (Non-Current Pension Costs Regulatory Account)	This section directed the BCUC to allow non-current pension cost variances to be deferred.	As discussed in Chapter 7, section 7.8.11, BC Hydro believes that it continues to be appropriate to defer the variances between actual and forecast non-current pension costs to the Non-Current Pension Costs Regulatory Account.
Section 7 (h) (i) (Rate Smoothing Regulatory Account)	This section directed the BCUC to allow BC Hydro to establish a rate smoothing regulatory account to defer portions of the approved revenue requirements in a particular fiscal year.	As an outcome of the Comprehensive Review, BC Hydro ceased using the Rate Smoothing Regulatory Account at the end of the third quarter of fiscal 2019. In this application, BC Hydro is not proposing to smooth rate increases and is requesting BCUC approval to close the Rate Smoothing Regulatory Account.

Direction Repealed	Purpose of Direction	Impact on this Application
Section 7 (h) (ii) (Real Property Sales Regulatory Account)	This section directed the BCUC to allow BC Hydro to establish a real property sales regulatory account to defer the variances between actual and forecast real property gains and losses.	As discussed in Chapter 7, section 7.8.7, BC Hydro believes that it continues to be appropriate to defer the variances between actual and forecast real property gains and losses to the Real Property Sales Regulatory Account.
Section 7 (i) (Interest Accrual for the First Nations Cost Regulatory Account and the Real Property Sales Regulatory Account)	This section directed the BCUC to allow the First Nations Costs Regulatory Account and the Real Property Sales Regulatory Account to accrue interest at BC Hydro's weighted average cost of debt.	As discussed in Chapter 7, section 7.9, BC Hydro believes it continues to be appropriate for the First Nations Costs Regulatory Account and the Real Property Sales Regulatory Account to accrue interest at BC Hydro's weighted average cost of debt.
Section 7 (j) and (k) (Regulatory Accounts and Rates)	These sections stated that the BCUC may allow BC Hydro to establish other regulatory accounts and that the BCUC must set rates to allow regulatory accounts to be cleared from time to time and within a reasonable period.	The repeal of these sections has no practical effect. These sections duplicated the BCUC's existing authority under the *Utilities Commission Act* to approve deferral and other regulatory accounts and to determine how those accounts should be cleared. BC Hydro is not seeking approval of any new regulatory accounts in this application. Section 2.4.1 provides further information on the requirements that inform the BCUC's rate setting function.
Section 8 (Dividend)	This section directed the BCUC to set rates that would ensure BC Hydro could collect sufficient revenue to allocate dividends to the Government of B.C. as specified under section 4 of the *BC Hydro Public Power Legacy and Heritage Contract Act* or section 35 of the *Hydro and Power Authority Act*. As explained in section 2.3, Heritage Special Directive No. HC1, issued under the *Hydro and Power Authority Act* states that BC Hydro is not required to pay a dividend to the Government of B.C. until its debt to equity ratio reaches 60:40.	The repeal of this section has no impact on this application. As shown in Appendix A, Schedule 9.0, BC Hydro's forecast debt to equity ratio is 80:20 in fiscal 2020 and 79:21 in fiscal 2021. As a result, BC Hydro is not forecasting any dividend payments to the Government of B.C. during the test period.

Direction Repealed	Purpose of Direction	Impact on this Application
Section 9 (1) and (2) (Rate Caps)	These sections related to BC Hydro's Fiscal 2017 to Fiscal F2019 Revenue Requirements Application. The sections directed the BCUC to cap rate increases at 4 per cent for fiscal 2017, 3.5 per cent for fiscal 2018 and 3 per cent for fiscal 2019.	None.
Section 9 (3) (Rate Re-Balancing)	This section prevented the BCUC from setting rates in fiscal 2017, fiscal 2018 and fiscal 2019 for the purpose of changing the revenue-cost ratio for a class of customers.	Section 5 of Direction No. 8 provides interim direction in this area ahead of proposed legislative amendments that are expected to be tabled in the B.C. Legislature this spring. It states that the BCUC must not set rates for fiscal 2020 or fiscal 2021 for the purpose of changing the revenue-cost ratio for a class of customers.
Section 10 (Deferral Account Rate Rider)	This section directed the BCUC to maintain the deferral account rate rider (DARR) at 5 per cent and to allow a portion of forecast revenue from the DARR to be accounted for as general revenue.	As discussed in Chapter 7, section 7.7.1, BC Hydro is seeking approval to reduce the DARR from 5 per cent to 0 per cent, effective April 1, 2019.
Section 11 (Cost Recovery)	This section directed the BCUC to not disallow the recovery in rates of the costs incurred with respect to: • The construction of extensions to BC Hydro's plant or system that came into service before fiscal 2017; • Energy supply contracts entered into before fiscal 2017; • The Rock Bay settlement; • Three First Nations settlements; • The October 4, 2013 settlement between Powerex and various California parties; • Costs incurred from the decommissioning of portions of Burrard Thermal not required for transmission support services; and • Costs deferred to the Smart Metering Infrastructure Regulatory Account.	Section 4 of Direction No. 8 provides direction in this area to recover costs related to previous policy decisions by the Government of B.C. It states that the BCUC must not disallow recovery in rates of the balance of BC Hydro's regulatory accounts as at March 31, 2019. It also states that the BCUC must also not disallow costs incurred by BC Hydro with respect to: • The construction of extensions to BC Hydro's plant or system that came into service before fiscal 2017; • Energy supply contracts entered into before fiscal 2017, and • Debt servicing costs related to the Rate Smoothing Regulatory Account approved by Order No. G-48-14.

Direction Repealed	Purpose of Direction	Impact on this Application
Section 12 (Expenditures for Export)	This section directed the BCUC to not comply with section 4 (5) of the *Clean Energy Act* when setting rates for BC Hydro for fiscal 2014, fiscal 2015, fiscal 2016, fiscal 2017, fiscal 2018 and fiscal 2019.	Section 6 of Direction No. 8 provides interim direction in this area ahead of proposed legislative amendments that are expected to be tabled in the B.C. Legislature this spring. It states that the BCUC must not comply with section 4 (5) of the *Clean Energy Act* when setting rates for fiscal 2020 and fiscal 2021.
Section 13 (Powerex)	This section directed the BCUC to not exercise any power under Part 3 of the *Utilities Commission Act* in regard to the gas and electricity trading activities of Powerex Corp.	Section 8 of Direction No. 8 provides interim direction in this area ahead of proposed legislative amendments that are expected to be tabled in the B.C. Legislature this spring. It states that the BCUC may not exercise any power or perform any duty under Part 3 of the *Utilities Commission Act* in regard to Powerex Corp.
Section 14 (Retail Access)	This section directed the BCUC to accept BC Hydro's withdrawal from any obligation to offer unbundled transmission services and to not set rates for BC Hydro that would result in the direct or indirect provision of unbundled transmission services to retail customers in British Columbia, or to those who supply such customers, except on application by BC Hydro.	Section 7 of Direction No. 8 provides direction in this area. It states that except on application by BC Hydro, the BCUC must not set rates for BC Hydro that would result in the direct or indirect provision of unbundled transmission services to retail customers in British Columbia, or to those who supply such customers.
Section 15 (Burrard Thermal)	These sections directed the BCUC to allow BC Hydro to cease operating those portions of Burrard Thermal that were not required for transmission to support services and to set depreciation rates for the classes of property, plant and equipment at Burrard Thermal, as specified, for fiscal 2015 and fiscal 2016. This section related to BC Hydro's Fiscal 2015 to Fiscal 2016 Revenue Requirements Application.	None. On December 29, 2016, the BCUC approved BC Hydro's application under section 41 of the *Utilities Commission Act* to permanently cease operating those portions of Burrard Thermal Generating Station that were not required for transmission support services. In our Previous Application, BC Hydro applied for depreciation rates for the classes of property, plant and equipment at Burrard Thermal. The depreciation rates for fiscal 2017 to fiscal 2019 were not directed. The BCUC reviewed and approved the depreciation rates proposed by BC Hydro.
Section 16	These sections related to previous revenue requirement applications.	None.

2.2.2 Government Plans to Table Legislation

As an outcome of the Comprehensive Review, the Government of B.C. also announced that it intends to table legislation to further update BC Hydro's regulatory framework. These plans have potential implications in the following three areas:

- **Integrated Resource Plan (IRP):** The Government of B.C. intends to propose amendments to the *Hydro and Power Authority Act* and the *Clean Energy Act* so that section 44.1 of the *Utilities Commission Act* applies to BC Hydro. This would mean that, going forward, BC Hydro's IRP would be reviewed and approved by the BCUC and not by the Government of B.C. On December 10, 2018, the Government of B.C. issued the BC Hydro Integrated Resource Plan Regulation (B.C. Reg. 266/2018) under the *Clean Energy Act* prescribing February 28, 2021 as the date for BC Hydro's next IRP.
- **Demand side management adequacy requirements:** The proposed application of section 44.1 of the *Utilities Commission Act* to BC Hydro, discussed above, would also require BC Hydro's traditional demand side management programs to meet the adequacy requirements set out in the Demand-Side Measures Regulation under the Act. These adequacy requirements set out the measures that a demand side management portfolio must include in order to be considered adequate. While BC Hydro is not currently required to meet these adequacy requirements, our demand side management plans have always been consistent with them. Table 10-7 in Chapter 10, section 10.3.1.4 shows how BC Hydro's proposed traditional demand side management plan aligns with the adequacy requirements set out in the Demand-Side Measures Regulation.
- **Areas Covered by Direction No. 8:** The Government of B.C. intends to propose amendments to the *Utilities Commission Act* to prohibit rate re-balancing except on application by BC Hydro and to clarify that the Act does not apply to Powerex. The Government of B.C. also intends to propose

amendments to the *Clean Energy Act* to eliminate the concept of expenditures for export. These amendments would have the same practical effect as the sections 5, 6, and 8 of Direction No. 8 to the BCUC.

2.3 BC Hydro's Powers and Mandate Are Unchanged

The *Hydro and Power Authority Act* sets out BC Hydro's powers and mandate. It also specifies the legislation that does and does not apply to BC Hydro and sets out the Government of B.C.'s ability to issue directives to BC Hydro. BC Hydro's powers and mandate under this Act have not changed.

BC Hydro's mandate is to generate, manufacture, conserve, supply, acquire and dispose of power and related products. It acts as an agent of the Government of B.C. and reports to the Government through the Minister of Energy, Mines, and Petroleum Resources. The Minister of Finance is the fiscal agent of BC Hydro. The Lieutenant Governor in Council appoints BC Hydro's Board of Directors and Chair. The Board is responsible for managing the affairs of BC Hydro or supervising the management of those affairs and may delegate its responsibilities to the President and Chief Operating Officer.

Section 32 of the *Hydro and Power Authority Act* sets out the legislation that does and does not apply to BC Hydro. Specifically, it states that the following sections of the *Utilities Commission Act* do not apply to BC Hydro:

- Long-term resource and conservation planning (section 44.1);
- Issuance of securities (sections 50 and 51 (c));
- Disposition of property (section 52);
- Creation and maintenance of reserve funds (section 57 (2));
- Lien on land (section 95); and
- Dissolution of a defaulting utility (section 98).

As discussed in section 2.2.2 above, the Government of B.C. plans to propose amendments so that BC Hydro would be subject to section 44.1 of the *Utilities Commission Act* going forward.

The effect of the remainder of these exclusions is that BC Hydro does not need to seek BCUC approval for the issuance of securities or for the disposition of property, franchises, licences, permits, concessions, privileges or rights.

Under section 35 of the *Hydro and Power Authority Act*, the Government of B.C. may issue directives to BC Hydro regarding dividend payments from BC Hydro to the Government of B.C., and may also direct BC Hydro to pay specified amounts to past or present customers. Heritage Special Directive No. HC1, issued under this section of the Act, states that BC Hydro is not required to pay a dividend to the Government of B.C. until its debt to equity ratio reaches 60:40. As BC Hydro's debt to equity ratio is currently higher than 60:40, there are no forecast dividend payments in the fiscal 2020 to fiscal 2021 test period. Further information is provided in Chapter 8, section 8.4.

2.4 Utilities Commission Act

This section provides an overview of the sections of the *Utilities Commission Act* that are relevant to the BCUC's review of this application, organized into the following three topic areas:

- Rate setting;
- Demand side management expenditures acceptance; and
- Review of capital expenditure schedules and energy acquisition expenditure schedules.

As a result of the changes from the Comprehensive Review, the BCUC's jurisdiction in these areas with regards to BC Hydro is now largely the same as other regulated utilities in British Columbia.

2.4.1 Applying the Standard Rate Setting Provisions and Principles to BC Hydro

In this application, BC Hydro is seeking the BCUC's approval to set rates for fiscal 2020 and fiscal 2021. Sections 59 to 61 of the *Utilities Commission Act* set out the rate setting functions of the BCUC and provide the BCUC with the authority to approve the rates sought in this application. These sections reflect standard regulatory principles that must be respected, while still providing the BCUC with discretion in setting rates.

Section 60 specifies that the BCUC must have due regard to the setting of a rate that:

- Is not unjust or unreasonable within the meaning of section 59;
- Provides the public utility with a fair and reasonable return on any expenditure made by it to reduce energy demands (i.e., demand side management expenditures); and
- Encourages public utilities to increase efficiency, reduce costs and enhance performance.

Section 59 defines what it means for a rate to be "unjust" or "unreasonable". A rate is unjust or unreasonable if it is:

- More than a fair and reasonable charge for service of the nature and quality provided by the utility;
- Insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property; or
- Unjust and unreasonable for any other reason as determined by the BCUC.

Section 60 (b.1) states that the BCUC may use any mechanism, formula or other method to set rates that it considers advisable. The section provides the BCUC with the authority to set BC Hydro's rates through PBR. This application is being submitted on a cost of service basis. In response to Directive 28 of the BCUC's Decision on BC Hydro's Previous Application, BC Hydro has included a report on PBR as Chapter 11 of this application.

Section 61 requires public utilities to file rate schedules with the BCUC, to receive the BCUC's consent before rescinding or amending a schedule, and to charge only those rates that are in accordance with the filed schedules. Appendix EE contains updated rate schedules which reflect the approvals that BC Hydro is seeking in this application.

2.4.2 Acceptance of a Demand Side Management Expenditures Schedule

Among other things, section 44.2 of the *Utilities Commission Act* states that a public utility may seek acceptance of demand side measures expenditures that it has made or anticipates making. In this application, BC Hydro is seeking the BCUC's acceptance of our proposed demand side measures expenditures schedule for fiscal 2020 and fiscal 2021 under section 44.2 of the *Utilities Commission Act*. Information on our proposed demand side management expenditures is provided in Chapter 10.

Section 44.2 of the Act sets out the factors that the BCUC must consider when deciding whether to accept a demand side measures expenditure schedule filed by a public utility. It specifies that the BCUC must consider the energy objectives set out in the *Clean Energy Act* as well as the utility's most recent long-term resource plan. It further states that the BCUC must accept an expenditure schedule if it considers that making the expenditures would be in the public interest. Otherwise, the BCUC must reject the schedule. Alternatively, the BCUC may accept or reject a part of the expenditure schedule. However, the BCUC cannot order specific modifications to the schedule.

2.4.3 Review of Capital Projects, Expenditures and Additions

The BCUC exercises oversight over BC Hydro's capital expenditures and additions. As discussed in Chapter 6, the capital expenditures and capital additions represent two distinct concepts when we discuss capital projects/programs. The distinction is important because BC Hydro has numerous capital projects that span across different test periods. Forecast capital expenditures reported in revenue requirements applications represent spending to be incurred during a test period, but will not affect rates until later when the project goes in service. Forecast capital additions represent capital projects going into service during the test period, and may reflect capital expenditures made in past years.

The BCUC can review BC Hydro's non-exempt capital projects and associated expenditures and additions through various means, including through the review of:

- major projects for which BC Hydro files an application for a Certificate of Public Convenience and Necessity (**CPCN**) under Section 45 of the *Utilities Commission Act;*
- major projects for which BC Hydro files an application for acceptance of capital expenditure schedules under Section 44.2 of the *Utilities Commission Act*;
- revenue requirements applications, in which BC Hydro forecasts capital expenditures and capital additions for a test period for the purpose of rate setting; and
- Prudency of total capital expenditures for a project, usually conducted after the completion of the project when the total expenditures are known.

BC Hydro files applications for a CPCN or acceptance of a capital expenditure schedule for projects with an authorized cost estimate[61] that exceeds the financial thresholds in BC Hydro's 2010 Capital Project Filing Guidelines. BC Hydro has

[61] The authorized cost estimate is the requested funding for a project, inclusive of all contingencies and reserves, and based on a fixed scope and in-service date.

proposed an update to these guidelines in the Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding currently before the BCUC. The BCUC also has discretion to direct BC Hydro to file a CPCN for projects that are below the financial thresholds, if they are extensions to BC Hydro's system.

The scope of the BCUC's review of capital expenditures and additions in a revenue requirements application depends on whether the project has been or will be subject to a separate CPCN or section 44.2 application, or is subject to legislation that exempts the project from BCUC review.

- For projects that are not expected to be subject to a separate CPCN or section 44.2 proceeding or legislated exemption, the BCUC may use this proceeding to examine project need and alternatives as well as the reasonableness of BC Hydro's forecast capital additions for the test period. The BCUC may also direct BC Hydro to seek a CPCN for any of these projects.
- For projects subject to a future CPCN or section 44.2 application, it is more efficient for the BCUC to conduct the assessment of project need and alternatives and the reasonableness of forecast capital expenditures during the future CPCN or section 44.2 proceeding.
- For projects that are subject to a legislated exemption, there is no need for an assessment of project need or alternatives or the reasonableness of forecast capital expenditures.

Appendix I includes a column that identifies projects that have a CPCN, section 44.2 acceptance or legislated exemption or that BC Hydro expects to be subject to a future CPCN or section 44.2 application.

Projects that are not subject to a future CPCN or section 44.2 application can be reviewed in a revenue requirements proceeding. For projects that were completed in the previous test period and are now in service, Appendix G provides an explanation of material variances between the original applied-for cost and final project cost.

Detailed consideration of BC Hydro's project execution is typically reviewed at project completion, when the total cost and outcomes are known. As explained in Chapter 7, section 7.8.2, the Amortization of Capital Additions Regulatory Account captures the difference between forecast and actual amortization of capital additions. This means that ratepayers only pay the actual amortization costs.

2.4.4 Energy Supply Contracts Are Reviewed Separately

BC Hydro is not seeking approval of energy supply contracts (sometimes referred to as Electricity Purchase Agreements) in this application. BC Hydro files separate applications pursuant to section 71 of the *Utilities Commission Act* seeking acceptance of each energy supply contract.

Chapter 4 provides information on our forecast Cost of Energy as these costs impact rates in fiscal 2020 and fiscal 2021. As explained in Chapter 4, section 4.5.1 and Chapter 7, section 7.7.1, the Non-Heritage Deferral Account captures the difference between forecast and actual cost of non-heritage energy. This means that ratepayers only pay the actual costs.

In its report on the Comprehensive Review, the Government of B.C. announced the Biomass Energy Program. This program is a cost and volume limited, transitional measure, intended to allow time for the forestry sector to develop and implement new product lines consistent with the industry's diversification and competitiveness goals. It allows for the continued operation of those biomass generating facilities with expiring Electricity Purchase Agreements over the next three years. The Government of B.C. has indicated that it intends to provide a direction to the BCUC with respect to the approval of the program documentation and to require the costs associated with the program to be recovered from ratepayers. Further information on this program is provided in Chapter 4, section 4.3.2.

2.4.5 Other Miscellaneous Sections of the *Utilities Commission Act*

Other sections of the *Utilities Commission Act* that may inform the BCUC's consideration of this application include:

- Section 3 which requires the BCUC to comply with directions issued to it by the Government of B.C. Section 2.5 provides summaries of directions issued to the BCUC under this section which apply to this application. Direction 8, also issued under this section, is explained in section 2.2.
- Section 22 which allows the Minister of Energy, Mines, and Petroleum Resources to issue regulations to exempt a public utility or "any equipment, facility, plant, project, activity, contract, service or system of the public utility" from BCUC regulation or certain aspects of BCUC regulation. An example of a ministerial regulation under this section is the Transmission Upgrade Exemption Regulation, discussed in section 2.5.8 below.
- Section 23 which provides the BCUC with a general supervision mandate over public utilities. BC Hydro is not relying on this section for any of the approvals it is seeking in this application.
- Section 24 which allows the BCUC to make inquiries about the conduct of the public utility business to keep itself informed and to ensure compliance of the public utilities with the Act. BC Hydro is not relying on this section for any approval sought in this application.
- Section 49 which permits the BCUC to adopt a uniform system of accounting for public utilities of the same class. As discussed in Chapter 1, section 1.6, BC Hydro is requesting that the BCUC rescind the requirement for BC Hydro to file Uniform System of Accounts information.

2.5 Other Regulations Affecting Revenue Requirements

There are a number of other regulations issued under the *Utilities Commission Act* that continue to affect aspects of BC Hydro's revenue requirements. They are summarized below.

2.5.1 Demand-Side Measures Regulation (B.C. Reg. 326/2008)

This regulation sets out the requirements for a demand side management portfolio to be considered adequate and for the demand side measures within that portfolio to be considered cost-effective. Chapter 10, section 10.3.1, explains how BC Hydro's proposed demand side measures expenditure schedule meets these requirements.

2.5.2 Shore Power Regulation (B.C. Reg. 291/2008)

This regulation is designed to encourage operators of cruise ships docked at Canada Place wharf in Vancouver to use port electricity instead of on-board, diesel-generated electricity. In setting the rate for shore power service, the BCUC must ensure that the rate allows BC Hydro to collect sufficient revenue to recover the costs incurred to provide that service. BC Hydro's proposed shore power rates for fiscal 2020 and fiscal 2021, in accordance with the approvals sought in this application, are set out in Appendix EE.

2.5.3 TMP Program Direction (B.C. Reg. 139/2015)

BC Hydro has a program to provide funding to increase the electrical efficiency of mills that use thermo-mechanical pulping processes (**TMP Program**). This direction requires the BCUC to allow BC Hydro to recover the costs incurred to carry out the TMP program up to $100 million. Further, the regulation requires the BCUC to allow BC Hydro to defer these costs to the DSM Regulatory Account. BC Hydro's TMP program expenditures are discussed in Chapter 10, section 10.3.2. Our demand side management expenditure request lists TMP program expenditures separately, because of this direction.

2.5.4 Mining Customer Payment Program Direction (B.C. Reg. 47/2016)

BC Hydro has a program to help mines remain in operation when prices for the commodities they produce are low (Mining Customer Payment Program). Government direction required the BCUC to approve Tariff Supplement No. 90. This tariff supplement allows eligible mining customers to temporarily defer payment of a portion of their BC Hydro electricity bills when commodity prices are low. It also prescribes the interest rates to be charged on those deferred payments and requires the deferred amounts, plus the prescribed interest, to be paid back as commodity prices increase. Any remaining balance is to be paid back when the program ends on March 14, 2021.

This Direction requires the BCUC to allow BC Hydro to establish a regulatory account for any impaired balances of participating mining customers. It also requires the BCUC to allow BC Hydro to recover the balance of this regulatory account in rates.

Information on the status on the Mining Customer Payment Plan and the Mining Customer Payment Plan Regulatory Account is provided in Chapter 7, section 7.8.

2.5.5 Meter Choices Program Direction (B.C. Reg. 203/2013)

BC Hydro has a program to provide legacy meters or radio-off meters to customers instead of smart meters for specified periods, if certain conditions are met (Meter Choices Program). This direction requires the BCUC to allow BC Hydro to collect sufficient revenue to recover the costs of this program from customers who are participating in the program. BC Hydro's Electric Tariff sets out the standard charges to recover these costs. This direction prohibits the BCUC from amending these charges, except on application by BC Hydro. BC Hydro is not applying to amend these charges in this application. The costs of the program are reflected in the forecast revenue requirements in this application.

2.5.6 Skagit Agreement Direction (B.C. Reg. 390/85)

On March 30, 1984, the Government of B.C. and the City of Seattle signed an agreement concerning the supply of electricity to the City of Seattle. The Government of B.C. subsequently assigned certain rights and obligations from this agreement to BC Hydro. This direction requires the BCUC to consider all payments related to this assignment as revenue to BC Hydro. Consistent with this direction, volumes delivered to and the related revenues received from Seattle City Light, which is the electricity provider for the City of Seattle, are recorded as domestic revenue as shown in schedule 14, line 8, of Appendix A. All else equal, these revenues reduce BC Hydro's revenue requirements.

2.5.7 Iskut Extension Project Direction (B.C. Reg. 137/2013)

This direction, as amended by B.C. Reg. 24/2019, exempts the Iskut Extension project from the CPCN requirements under section 45, 46 and 47 of the *Utilities Commission Act*. It also requires the BCUC to ensure that BC Hydro is able to collect sufficient revenue to recover its costs related to the Iskut Extension Project, including any costs for related agreements and negotiations with First Nations. As shown in Chapter 6, Table 6-4, the project cost will be approximately $113 million at completion.

2.5.8 Transmission Upgrade Exemption Regulation (B.C. Reg. 140/2013)

This direction, as amended by B.C. Reg. 160/2018, exempts BC Hydro from Part 3 of the *Utilities Commission Act* with regards to:

- A series capacitor station and related facilities and equipment in the vicinity of the District of Vanderhoof, the Village of Burns Lake and the Village of Telkwa;
- Various upgrades and additions at the Skeena and Minette substations; and
- Construction, operation, upgrades or extensions, reasonably expected to come into service before October 1, 2025, to provide service to an LNG facility in the

vicinity of the District of Kitimat and to provide service to facilities necessary for the construction of that LNG facility.

This direction exempts the Northwest Substation Upgrade Project (which primarily consists of the construction, operation, upgrades and extensions of BC Hydro's facilities to provide service to LNG Canada) from Part 3 of the *Utilities Commission Act*, provided that these facilities are placed in service before October 1, 2025. In Directive 3 of its Decision on our Previous Application, the BCUC ordered BC Hydro to file a CPCN for the Northwest Substation Upgrade Project. BC Hydro is requesting an amendment to Directive 3 to remove this requirement as it is inconsistent with this regulation.

2.5.9 LNG Customers Direction (B.C. Reg. 197/2018)

This direction removes a previous provision that prevented LNG customers from receiving service under BC Hydro's transmission rate schedules. It states that, except on application by BC Hydro, the BCUC must not set any rates for transmission service to LNG customers other than the rates applicable under Rate Schedules 1823, 1825, 1827 or 1852. In addition, it states that the BCUC must allow BC Hydro to rescind Tariff Supplements 91 and 92 so that FortisBC's Tilbury Island LNG facility can receive service under Rate Schedule 1823. BC Hydro expects to submit a separate application to the BCUC to rescind Tariff Supplements 91 and 92. BC Hydro is not applying for any new rates for LNG customers in this application.

2.5.10 Special Direction No. 9 (B.C. Reg. 157/2005)

This direction prevents the BCUC from requiring BC Hydro to provide storage services.

2.5.11 Special Direction No. 10 (B.C. Reg. 245/2007)

This direction requires the BCUC to consider the objective for BC Hydro to achieve electricity self-sufficiency when considering CPCN applications and energy supply contracts. It also requires that the BCUC ensure BC Hydro collects sufficient revenue in each fiscal year to achieve self-sufficiency. The self-sufficiency objective is explained further in section 2.6.1 below.

This direction also set out factors to guide the BCUC's consideration of certain biomass contracts under section 71 of the *Utilities Commission Act*.

Lastly, this direction requires the BCUC to ensure that BC Hydro's rates available to customers in the Non-Integrated Area are also available to customers who receive electricity service under the Remote Communities Regulation. It also requires that the BCUC ensure BC Hydro collects sufficient revenue in each fiscal year to recover costs related to providing this service. The Remote Communities Regulation is discussed further in section 2.7.

2.6 Clean Energy Act

The *Clean Energy Act* continues to apply to BC Hydro. It sets out considerations for BC Hydro's cost of energy and DSM expenditures and requires the BCUC to allow BC Hydro to recover certain costs.

2.6.1 Self-Sufficiency is Considered in Forecasting Energy Cost

The *Clean Energy Act* sets out the energy objectives of British Columbia in section 2. This includes the objective for BC Hydro to achieve electricity self-sufficiency by 2016 and each year after by meeting its electricity supply obligations solely from generating facilities within the province. The electricity self-sufficiency regulation issued under the *Clean Energy Act* states that these obligations are to be determined based on the mid-level load forecast. It also states that BC Hydro must be able to meet these obligations assuming the maximum amount of annual energy generated under average water conditions.

The BCUC is required to ensure that rates allow BC Hydro to collect sufficient revenue to recover the costs associated with the achievement of electricity self-sufficiency.

2.6.2 Energy Objectives Are Considered for Demand Side Management

The BCUC must consider the energy objectives in section 2 of the *Clean Energy Act* when reviewing applications made under sections 44.1, 44.2, 45 and 71 of the *Utilities Commission Act*. Accordingly, the energy objectives are one of the factors the BCUC must consider when determining whether to accept or reject BC Hydro's proposed demand side management expenditures in this application. Chapter 10, Table 10-6 of this application demonstrates how BC Hydro's proposed demand side management expenditures align with the energy objectives.

2.6.3 Rates Must Recover Costs of Exempt Projects

Section 7 of the *Clean Energy Act* exempts the various projects, programs, contracts and expenditures from BCUC review under sections 45 to 47 and 71 of the *Utilities Commission Act*. Section 8 requires the BCUC to ensure that BC Hydro collects sufficient revenue to recover the costs associated with these projects, programs, contracts and expenditures. The capital projects exempted by section 7 of the *Clean Energy Act* that have capital additions in fiscal 2020 or fiscal 2021 are identified in Appendix I.

2.6.4 Rates Must Recover Costs of Prescribed Undertakings

Section 18 of the *Clean Energy Act* requires the BCUC to allow BC Hydro to collect sufficient revenue to recover costs incurred for prescribed undertakings. Prescribed undertakings are projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in British Columbia. The Greenhouse Gas Reduction Regulation issued under the *Clean Energy Act* (B.C. Reg. 102/2012) sets out prescribed undertakings for electrification. Some undertakings must meet cost effectiveness test to be prescribed undertakings.

The Peace Region Electricity Supply Project, which has planned capital expenditures in fiscal 2020 and fiscal 2021, meets the requirements to be considered a prescribed undertaking.[62] Under the requirements of the regulation, it is not subject to the cost effectiveness test.

BC Hydro's proposed low carbon electrification expenditures for fiscal 2020 and fiscal 2021 also meet the requirements to be considered prescribed undertakings for electrification including the cost effectiveness test where applicable.

The Direction to the BCUC Respecting Undertaking Costs, issued under section 3 of the *Utilities Commission Act* (B.C. Reg. 77/2017), requires the BCUC to allow BC Hydro to defer the costs incurred for prescribed undertakings to the Demand Side Management (**DSM**) Regulatory Account. In this application, BC Hydro is requesting BCUC approval to defer low-carbon electrification expenditures to the DSM Regulatory Account, consistent with this Direction. BC Hydro has included information on forecast expenditures related to these prescribed undertakings in Chapter 10, section 10.4.3 and in Appendix Y.

2.6.5 Standing Offer Program is Indefinitely Suspended

Section 15 of the *Clean Energy Act* states that BC Hydro must establish and maintain a standing offer program to acquire electricity from eligible facilities, except in the prescribed circumstances. As part of the Comprehensive Review, the Government of B.C. issued a Regulation (B.C. Reg. 23/2019) to specify a new prescribed circumstance. Through the Standing Offer Program, BC Hydro has contracted with facilities totalling more than 170 MW of nameplate capacity. The effect of the Regulation is that BC Hydro is not obligated to maintain the Standing

[62] In Exhibit B-18 of the Fiscal 2017 to Fiscal F2019 Revenue Requirements Application, BC Hydro informed the BCUC that "OIC 101 adds as prescribed undertakings for the purpose of section 18 of the *Clean Energy Act* investments in infrastructure in Northeast British Columbia that primarily serve natural gas producers and processors (the new section 4(2) of the Greenhouse Gas Reduction (Clean Energy) Regulation). This will include BC Hydro's planned transmission project known as the Peace Region Electricity Supply (**PRES**) Project and accordingly, should we decide to proceed with PRES, BC Hydro will not be filing an application under section 45(5) of the *Utilities Commission Act* for a Certificate of Public Convenience and Necessity for the PRES Project."

Offer Program while the cumulative capacity of facilities under the program exceeds 100 MW. Through the Standing Offer Program, BC Hydro has contracted with facilities totalling more than 170 MW of nameplate capacity. In accordance with the regulation, BC Hydro has indefinitely suspended the Standing Offer Program. While this means that BC Hydro will not be acquiring additional electricity through the Standing Offer Program, existing Electricity Purchase Agreements under this program remain valid.

2.7 BC Hydro's Obligation to Provide Service to Remote Communities

When setting rates for BC Hydro, the BCUC must comply with any regulations made by the Government of B.C. under the BC Hydro Public Power Legacy and Heritage Contract Act. In addition, BC Hydro must provide the service required by the regulations made under this Act in accordance with the terms and conditions specified in those regulations. The Remote Communities Regulation is the only regulation currently in effect under this Act. It requires BC Hydro to provide service to customers in 11 remote communities, which are set out in a schedule under the regulation.

2.8 Standard Charges

Section 11 of BC Hydro's Electric Tariff includes its Schedule of Standard Charges. Some of these charges were last approved by BCUC Order No. G-5-17 to BC Hydro's 2015 Rate Design Application. As part of that process, BC Hydro proposed to regularly review its Standard Charges and to propose changes, as required, in upcoming revenue requirement applications so that the charges would remain current.

BC Hydro is not proposing to update any of the Standard Charges in this application. Many of the Standard Charges include cost elements of Customer Service functions that were previously provided by Accenture. BC Hydro has only recently repatriated Customer Service functions from Accenture and is still working to identify the cost of tasks involved in the Account Charge, Returned Payment Charge and Minimum Reconnection Charges.

BC Hydro plans to review and file separate applications related to the methodologies for calculating the service connection, Meter Choices Program and Net Metering related Standard Charges, in the future.

2.9 Summary of Legal Authority for Orders Sought

The approvals that BC Hydro is seeking in this application are set out in Chapter 1, section 1.6. Table 2-2 below provides a summary of these requests as well as the applicable legislation and regulations and the role of the BCUC within that framework.

Table 2-2 Summary Approvals Sought and Legal/Regulatory Framework

Approvals Sought	Applicable Legislation and Regulations	BCUC's Role
A reduction of the DARR from 5 per cent to 0 per cent on April 1, 2019; and Permanent general increases of 6.85 per cent on April 1, 2019 (for fiscal 2020) and 0.72 per cent on April 1, 2020 (for fiscal 2021). If approved, these requests would result in a net bill increase of 1.76[63] per cent on April 1, 2019. The net bill increase on April 1, 2020 would be the same as the proposed general rate increase of 0.72 per cent. We request that these changes be made effective April 1, 2019, on an interim basis, pending a final BCUC decision on our application. Tariff Sheets reflecting these requests are provided in Appendix EE.	Sections 59-61 of the *Utilities Commission Act*	The BCUC must approve rates that are just and reasonable, with reference to BC Hydro's forecast revenue requirements. BC Hydro's forecast revenue requirements reflect a variety of other legislative and regulatory requirements as discussed in this Chapter.
Refund the forecast fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and interest applied to the Cost of Energy Variance Accounts over the fiscal 2020 to fiscal 2021 test period. This would result in a net credit to the benefit of ratepayers of $329.1 million being amortized into rates during the test period; Defer any variances related to the accounting for EPAs determined to be leases under IFRS 16, which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account; Continue to defer, on an annual and ongoing basis, any variances between forecast and actual dismantling costs. In the Dismantling Cost Regulatory Account, continue to apply interest to the balance of the account and recover the forecast interest charged to the account each year,	Sections 59-61 of the *Utilities Commission Act*	The BCUC has the power to direct that certain components of the forecast revenue requirements be deferred by recording the amount in a regulatory account for future recovery. The approved rates/revenue requirements must reflect reasonable amortization expense from previously deferred amounts.

[63] Offsetting the requested general rate increase of 6.85 per cent with the requested reduction of the DARR from 5 per cent to 0 per cent reduces the net bill increase by more than 5 per cent because the DARR is applied after general rate increases. The following equation demonstrates how this works:
Start: Bill with 5 per cent DARR: $105.00
Adjust: DARR from 5 per cent to 0 per cent: $100.00
Adjust: General Rate Increase of 6.85 per cent: $106.85
$106.85/$105.00 = 1.0176.

Approvals Sought	Applicable Legislation and Regulations	BCUC's Role
and continue to recover the forecast account balance at the end of a test period over the next test period; Remove the reference to the "Prescribed Standards" from the scope of what may be deferred to the Site C Regulatory Account, as BC Hydro has fully adopted IFRS. This will allow BC Hydro to continue to defer to the Site C Regulatory Account any costs related to the Site C Project that are not able to be capitalized. Close the Capital Project Investigation Costs Regulatory Account at the end of fiscal 2021 as its balance will be fully amortized into rates at that time; and Close the Rate Smoothing Regulatory Account as this account has a zero balance and BC Hydro is not proposing to smooth rates over the fiscal 2020 to fiscal 2021 test period. Further information on requests related to BC Hydro's regulatory accounts is provided in Chapter 7, section 7.7.		
Defer any variances between forecast and actual amounts related to the Biomass Energy Program, which are not eligible for deferral treatment under existing orders to the Non-Heritage Deferral Account. This will ensure BC Hydro recovers its costs with respect to the Biomass Energy Program. For further information in this request, please refer to Chapter 7, section 7.7.1.3.	Sections 59-61 of the *Utilities Commission Act*	The Government of B.C. has indicated that it intends to provide a direction to the BCUC with respect to the approval of the program documentation and to require the costs associated with the program to be recovered from ratepayers.
Defer low-carbon electrification expenditures to the DSM Regulatory Account. For further information in this request, please refer to Chapter 7, section 7.7.3.	Direction to the BCUC Respecting Undertaking Costs (B.C. Reg. 77/2017)	The BCUC must allow BC Hydro to defer these expenditures to the DSM Regulatory Account.
Set depreciation rates for the Burrard synchronous condense facility, for new Water Rights, Infrastructure Rights and LED Streetlights asset classes and for three new asset classes for agreements recognized as leases under International Financial Reporting Standard 16, Leases. For further information on this request, please refer to Chapter 8, section 8.12;	Sections 59-61 of the *Utilities Commission Act*	The BCUC must set proper and adequate rates of depreciation.

Approvals Sought	Applicable Legislation and Regulations	BCUC's Role
Approve the Open Access Transmission Tariff (OATT) rates, as set out in Chapter 9, Table 9-8. For further information on this request, please refer to Chapter 9.	Sections 59-61 of the *Utilities Commission Act*	The BCUC must approve rates that are just and reasonable, with reference to BC Hydro's forecast revenue requirements. BC Hydro's forecast revenue requirements reflect a variety of other legislative and regulatory requirements as discussed in this Chapter.
Accept a DSM expenditure schedule of $90.8 million in fiscal 2020 and $116.3 million in fiscal 2021. For further information on this request, please refer to Chapter 10.	Section 44.2 of the *Utilities Commission Act* Section 2 of the *Clean Energy Act* Demand-Side Measures Regulation	The BCUC must accept the schedule if it considers that making the expenditures would be in the public interest. The public interest inquiry includes consideration of "British Columbia's energy objectives" under the *Clean Energy Act*. Alternatively, the BCUC may reject the schedule or reject a part of the schedule.
Reconsider and vary Directive 3 of the BCUC's Decision on BC Hydro's Fiscal 2017 to Fiscal 2019 Revenue Requirements Application which, among other things, directs BC Hydro to file a CPCN application for the Northwest Substation Upgrade project. This directive is inconsistent with the Transmission Upgrade Exemption Regulation. Further information is provided in section 2.5.8.	Section 99 of the *Utilities Commission Act* Transmission Exemption Regulation	The BCUC must comply with the Transmission Upgrade Exemption Regulation. The BCUC may reconsider a decision and may vary or rescind the decision to comply with the Regulation.
Reconsider and rescind Directive 61 of the BCUC's Decision on BC Hydro's Fiscal 2005 to Fiscal 2006 Revenue Requirements Application. This Directive is inconsistent with section 4 of the Demand-Side Measures Regulation. For further information, please refer to Chapter 10, section 10.5.5.	Section 99 of the *Utilities Commission Act* Demand-Side Measures Regulation	The BCUC may reconsider a decision and may vary or rescind the decision.

Approvals Sought	Applicable Legislation and Regulations	BCUC's Role
Reconsider and rescind Directive 57 of the BCUC's Decision on BC Hydro's Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, which had required BC Hydro to adopt a uniform system of accounts. For further information, please refer to Chapter 1, section 1.6.	Section 49 of the *Utilities Commission Act* Section 99 of the *Utilities Commission Act*	The BCUC may adopt a uniform system of accounting for public utilities of the same class. The BCUC may reconsider a decision and may vary or rescind the decision.

BC Hydro
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Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Chapter 3

Load and Revenue Forecast

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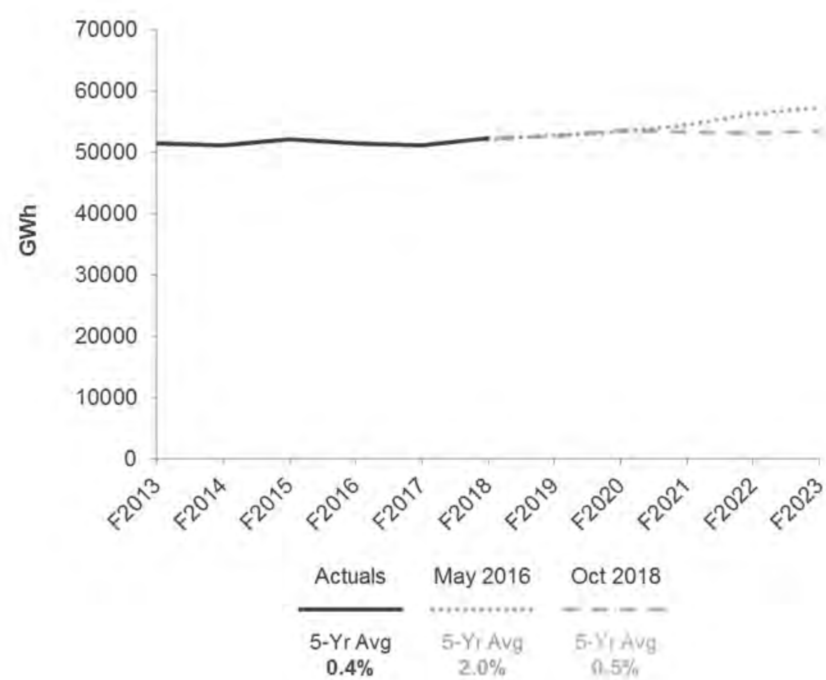
3.1 Introduction

This chapter provides our Load Forecast[64] and associated Revenue Forecast. The forecasts for fiscal 2020 and fiscal 2021 are used in the calculation of the test period revenue requirements.

The Load Forecast was completed in October 2018. Overall, BC Hydro is forecasting a lower load growth rate relative to the May 2016 Load Forecast contained in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (**Previous Application**). This is shown in Figure 3-1 below.

Figure 3-1 Electricity Sales Summary – October 2018 Load Forecast vs. May 2016 Load Forecast[65]



64 For the purposes of this application, the terms load forecast and electricity sales are used interchangeably.

65 The graph shows a fiscal 2019 to fiscal 2023 compound growth rate using billed sales forecast after rates and after DSM savings.

While events since October 2018, such as the announcement of the Government of B.C.'s CleanBC Plan are not included as part of this Load Forecast, they are captured within the uncertainty discussion provided in section 3.3.6.

The information provided in this chapter on our Load Forecast is supplemented by BC Hydro's Electric Load Forecast Report Fiscal 2019 to Fiscal 2024 (October 2018),[66] which is provided as Appendix O to this application. Appendix O provides a comprehensive description of the methods and results of the Load Forecast discussed in this chapter. Collectively, the information provided demonstrates why we believe that the Load Forecast, and the associated Revenue Forecast, are reasonable for the purposes of setting rates in the test period.

This Chapter is organized around the following key points:

- Section 3.2 explains our load forecast methods, and the inputs used for each customer sector. We conclude that our methodology and inputs are the appropriate basis for the Load Forecast in this application considering:
    - ▶ The recent performance of our own methodology;
    - ▶ The endorsement of the methodology by an internal audit review conducted by an independent expert;
    - ▶ Improvements to our methodology, which address the audit recommendations and the issues raised by the BCUC;
    - ▶ The Auditor General's recent determination that our methodology is robust and compares favourably with industry standards; and
    - ▶ The favourable performance of our methodology relative to an alternative short-term forecast methodology.

[66] Appendix A, Schedule 14 of this application contains the electricity sales forecasts by sector from fiscal 2019 to fiscal 2021. Appendix A, Schedule 14 and the forecast results in section 3.3 show the electricity sales forecast on an accrued sales basis. Appendix O shows the electricity sales forecast on a billed sales basis. For further details on accrued vs. billed sales refer to Appendix O.

- Section 3.3 presents the results of the load forecast, both the mid forecast and the high and low uncertainty bands.
  - Demand for electricity is forecast to increase by approximately 650 GWh or 1.2 per cent from fiscal 2019 to fiscal 2021; and
  - The high and low band around the forecast is the product of Monte Carlo analysis, and illustrates the range of uncertainty.
- Section 3.4 explains our Revenue Forecast methodology, which is straightforward and unchanged from the methodology used in the Previous Application.
- Section 3.5 presents the results of the Revenue Forecast by customer sector, based on the output of the improved load forecast methodology.

3.2 The Improved Load Forecast Methodology

The Load Forecast is an important input to BC Hydro's revenue requirements during the test period because it provides the basis for estimating future electricity sales revenues from our existing and future customers. It is also an input to our generation system optimization studies, which are undertaken to estimate market purchases and market purchases costs. We explain below five reasons why the methodology and inputs used in the Load Forecast in this application are appropriate:

(i) The recent strong performance of our own methodology;

(ii) The endorsement of the methodology by an audit review conducted by an independent expert;

(iii) Improvements to our methodology, which address the audit recommendations and the issues raised by the BCUC;

(iv) The Auditor General's recent endorsement of our methodology as "robust"; and

(v) The favourable performance of our methodology relative to an alternative short term forecast methodology.

3.2.1 Sales Since May 2016 Have Closely Tracked the Load Forecast

The Load Forecast for the Previous Application was developed in May 2016. Actual results have tracked within 0.1 per cent to 0.5 per cent against this Load Forecast for fiscal 2017 and fiscal 2018, which are well within a range of expectancy based on industry benchmarks.

3.2.2 Independent Expert Endorsed Overall Methodology in a Recent Audit

An August 2017 audit of our load forecasting function endorsed the overall load forecast methodology, while making some recommendations as to how to improve upon particular aspects which have been substantially incorporated into the 2018 Load Forecast.

The audit of our load forecasting function was completed by BC Hydro Audit Services (**Load Forecasting Audit**). The objective was to review load forecasting processes to ensure timely and reliable forecasts. A copy of this audit is included as Appendix P to this application.

The audit relied on an independent subject matter expert, GDS Associates Inc., retained specifically for the audit. GDS Associates Inc. is a U.S. based firm with load forecasting experience within the electrical utility industry. The principal at GDS Associates Inc., who undertook the work, has over 30 years of load forecasting experience. His experience included preparing load forecasts for utility clients (ranging from day-ahead to annual and long-term time frames), and filing regulatory testimony related to load forecasting and statistical analyses.

GDS's findings, which were adopted by the Load Forecasting Audit, included:

- "Overall, the load forecasting function at BC Hydro compares favorably to industry standards and to other large electric utilities in North America. No critical weaknesses were found."

- "Load forecasting methodologies are consistent with best practices and load forecast outputs are provided to users and stakeholders on a timely basis."
- "The greatest risk of load forecasting inaccuracy falls on the industrial class and is due to the uncertainty of future economic activity and the volatility of many individual customer loads."
- "Areas for improvement identified primarily relate to making adjustments to forecast models and inputs to enhance overall forecast accuracy."[67]

The Load Forecasting Audit included recommendations focused on adjustments to our models and inputs that could improve forecast performance. For example, the audit recommended that we "accelerate internal studies and development on the elasticity coefficients used in the development of the Load Forecast, including price elasticity and statistical adjusted end-use (**SAE**) model elasticity." As discussed next, we have addressed the audit recommendations.

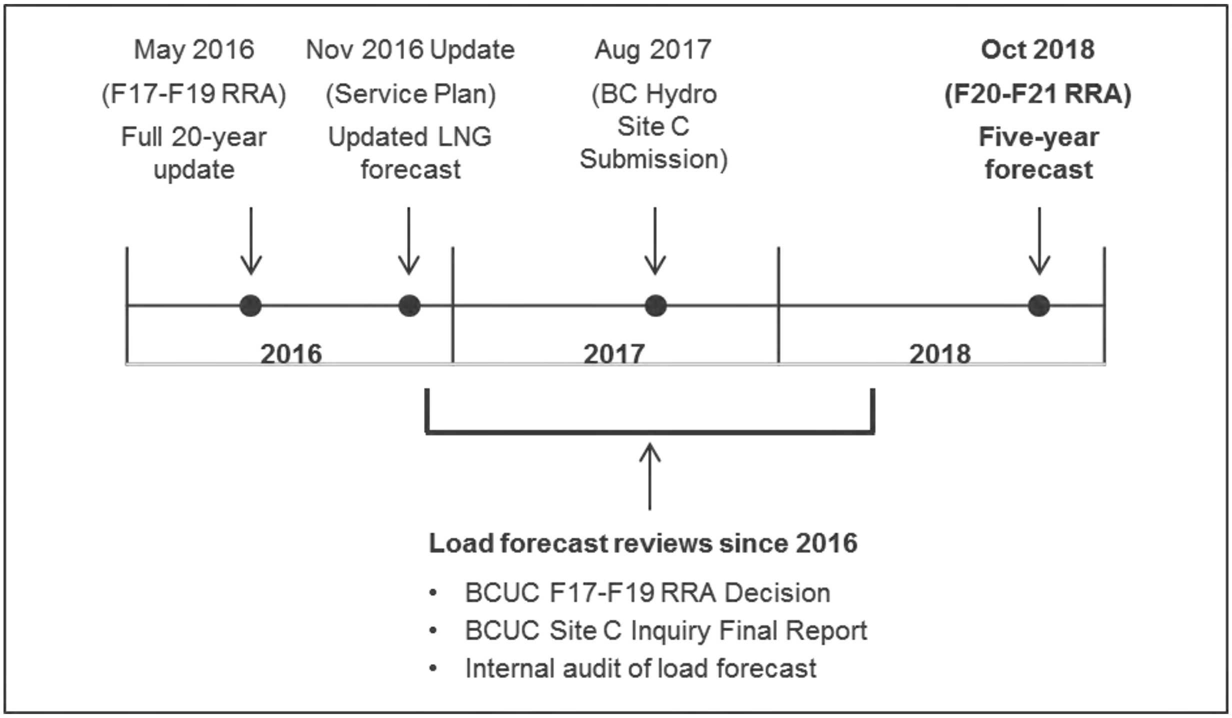
3.2.3 BC Hydro Has Addressed the Audit Recommendations and the Issues Raised by the BCUC

The load forecast used for the Previous Application was prepared in May 2016. Since that time, we have received feedback from the BCUC as well as the audit recommendations referenced above. The methodological improvements described later in this chapter address the issues identified by the BCUC.

Figure 3-2 below shows the load forecasts, the BCUC regulatory review and decisions, and the Load Forecasting Audit that have occurred since that time.

[67] All quotes have the same reference – Appendix P, page 5.

Figure 3-2 Load Forecast Chronology – 2016 to 2018



Load forecasts produced or reviewed since the May 2016 Load Forecast include:

- **May 2016 (November 2016 Update):** Prepared for BC Hydro's fiscal 2018 to fiscal 2020 Service Plan. It updated the LNG terminal forecast to reflect delays in projects' final investment decisions.
- **May 2016 (August 2017 Review):** BC Hydro's submission to the BCUC to the Site C Inquiry included a review of BC Hydro's May 2016 Load Forecast.
- **October 2018 Load Forecast:** Developed for this application. It is our new forecast of electricity sales from fiscal 2019 to fiscal 2024.
- The BCUC reviews since the May 2016 Load Forecast include:
  - **August 2017, Fiscal 2017 to Fiscal 2019 Revenue Requirements Application Decision:** The BCUC found that BC Hydro's May 2016 Load Forecast was, "reasonable for use for the fiscal 2017 to fiscal 2019 test

period", but acknowledged concerns regarding price elasticity and historical load forecast accuracy;[68]

- The BCUC acknowledged BC Hydro's observation that electricity rate increases "were known to industrial customers when BC Hydro's key account managers conducted their forecast surveys. Accordingly, [the BCUC was] satisfied that the issue of price elasticity for future, unknown price increases [was] not an issue in the test period;"[69] and
- The BCUC further noted that "other utilities such as Pacific Northern Gas, FortisBC (natural gas) and FortisBC (electricity) use a different load forecast methodology for [their] short term forecast for setting rates as compared to its long term forecast for resource planning."[70]

- **November 2017, Site C Inquiry Final Report**: The Inquiry was more focussed on long-term demand, as opposed to the short-term forecast for a particular test period. However, the BCUC identified a number of issues related to BC Hydro's Load Forecast, including:
  - The accuracy of the industrial forecast and, in particular, that "BC Hydro had not made a probabilistic assessment of the likelihood of the LNG load materializing";[71]
  - "GDP[72] and disposable income estimates used by BC Hydro in its current Load Forecast are higher than similar Conference Board of Canada estimates;"[73] and

[68] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), Appendix B, page 12.
[69] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), Appendix B, page 6.
[70] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), Appendix B, page 11.
[71] BCUC Final Report With Respect to the Site C Inquiry (November 1, 2017), page 78.
[72] All instances of GDP are Real GDP and not Nominal GDP.
[73] BCUC Inquiry Respecting Site C – Final Report (November 1, 2017), page 78.

- For price elasticities, "long-run price elasticity used by BC Hydro for all rate classes [being] too low in magnitude."[74]

Key concerns expressed by the BCUC and the Load Forecasting Audit about the methodology have now been addressed. Table 3-1 provides examples of BCUC concerns raised and how they have been addressed. Information on specific improvements is embedded within the discussion of each of the customer sector forecasts in the sections immediately following this one.

Table 3-1 Summary of BC Hydro's Response to BCUC Recommendations and Comments

Fiscal 2017 to Fiscal 2019 Revenue Requirements Application Decision	
BCUC Recommendations/Comments	**Location of BC Hydro's Response**
"Panel acknowledges the concerns of AMPC regarding price elasticity use for industrial customers," but is nevertheless "satisfied that the issue of price elasticity for future unknown price increases is not an issue in the test period."[75]	BC Hydro engaged DNV GL consulting to review price elasticity and recommended increasing elasticity values from -0.05 to -0.1 and applying price elasticity across all customer sectors. Please refer to section 3.2.6.2.
"Panel further notes that other utilities such as Pacific Northern Gas, FortisBC (natural gas) and Fortis BC (electricity) use a different load forecast methodology for their short term forecast for setting rates as compared to its long term forecast for resource planning."[76]	We reviewed alternative short- term methodologies and developed a comparator forecast using FortisBC (electricity) methods. Please refer to section 3.2.11 and Table 3-2.

[74] BCUC Inquiry Respecting Site C – Final Report (November 1, 2017), page 79.
[75] BCUC Decision on BC Hydro's Fiscal 2017 to Fiscal 2019 Revenue Requirements (March 1, 2018), Appendix B, page 6.
[76] BCUC Decision on BC Hydro's Fiscal 2017 to Fiscal 2019 Revenue Requirements, Appendix B (March 1, 2018), page 11.

BCUC Site C Inquiry Final Report	
BCUC Recommendations/Comments	**Location of BC Hydro's Response**
"Panel agrees with several parties who express concern with the fact that BC Hydro has not made a probabilistic assessment of the likelihood of the LNG load materializing."[77]	We have now aligned how we forecast sales to LNG customers in a manner consistent with other large industrial customers: using the probabilistic assessment approach. Please refer to section 3.2.8.2.
"Panel finds the GDP and disposable income used by BC Hydro are higher than similarly Conference Board of Canada estimates."[78]	As part of BC Hydro's normal competitive procurement practices, the Conference Board of Canada was the successful proponent on an RFP for economic consulting services to provide us with a sub-regional and aggregate economic forecast for the province.

3.2.4 Auditor General Characterizes Our Process as "Robust" and Our Capability as Comparing Favourably With Industry Standards

The Auditor General recently issued a report on BC Hydro's asset management practices. The audit included whether BC Hydro has the information, practices, processes and systems needed to support good asset management. That included information collection about matters such as "forecasting future demand for assets". The Auditor General characterized the Load Forecast process as "robust" and made the following observations (emphasis in original):

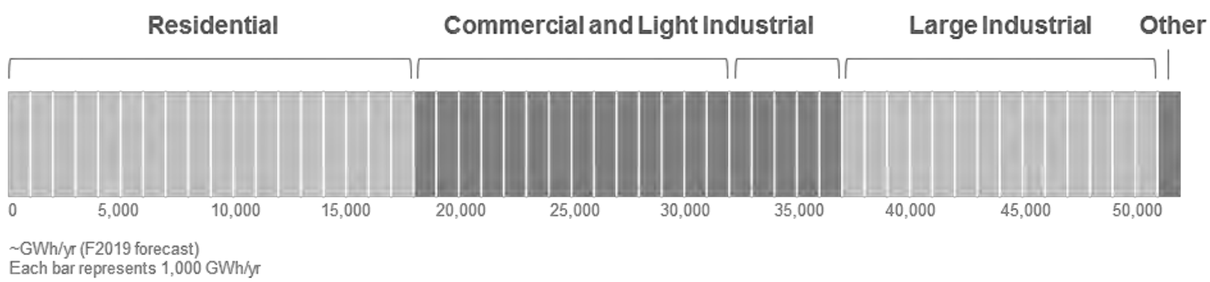
> "**Load forecasting process is robust**
>
> BC Hydro has a load-forecasting capability that compares favourably with industry standards. The process it uses includes three components:
>
> > Projecting what will drive residential and commercial demand at a future date;
> >
> > Conducting sensitivity analyses to adjust for various demand outcomes; and
> >
> > Producing a set of demand probability scenarios (low, medium and high peak load forecasts) which can be applied to strategic planning."

[77] BCUC Inquiry Respecting Site C – Final Report (November 1, 2017), page 78.
[78] BCUC Inquiry Respecting Site C – Final Report (November 1, 2017), page 78.

3.2.5 The Load Forecast Aggregates Sector Forecasts

BC Hydro's Load Forecast is divided into the following four sectors as shown in Figure 3-3: Residential, Commercial and Light Industrial, Large Industrial and Other[79] (which includes inter-utility sales, firm exports, street lighting and irrigation demand). Although similarities exist with the load forecasting methods used for these sectors, the processes differ sufficiently such that they are each described separately in the following sections.

Figure 3-3 BC Hydro Load Forecast by Customer Sector



3.2.6 Residential Sector Methodology Has Been Improved

The residential sector consists of approximately 1.8 million accounts and represents approximately one-third of total sales. The residential forecast retains the same basic methodology as was used in the Previous Application. However, we have made some notable improvements to it.

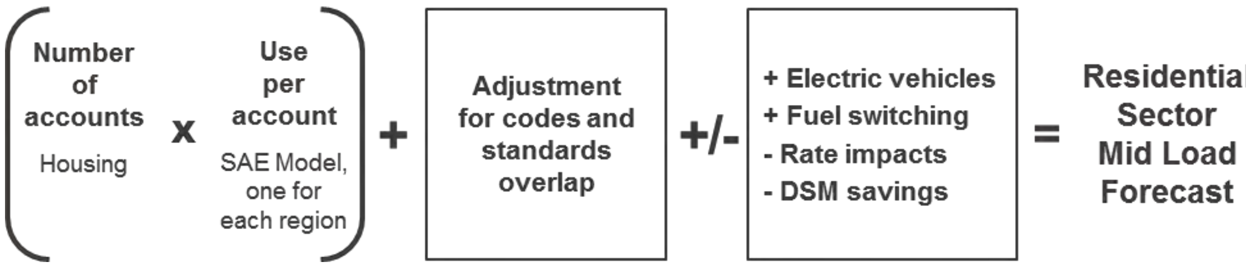
3.2.6.1 Residential Forecast Retains Same Basic Methodology

As in the past, BC Hydro develops residential sector forecasts for four regions: the Lower Mainland, Vancouver Island, South Interior and the North Region. These regional forecasts capture geographic differences in population growth, disposable income and temperature.

[79] Chapter 3 splits the Load Forecast into four sectors as it conforms to how BC Hydro presents the data in the Domestic Energy Sales and Revenue in Appendix A, Schedule 14, and section 3.5. Appendix O splits BC Hydro's Load Forecast in to five sectors by not combining the Commercial and Light Industrial sectors.

The process for forecasting residential sector sales is shown in Figure 3-4, showing sales are a product of the number of accounts and anticipated electricity use per account. The process of developing the forecast is outlined in the following steps.

Figure 3-4 Residential Sector Load Forecast Methodology[80]



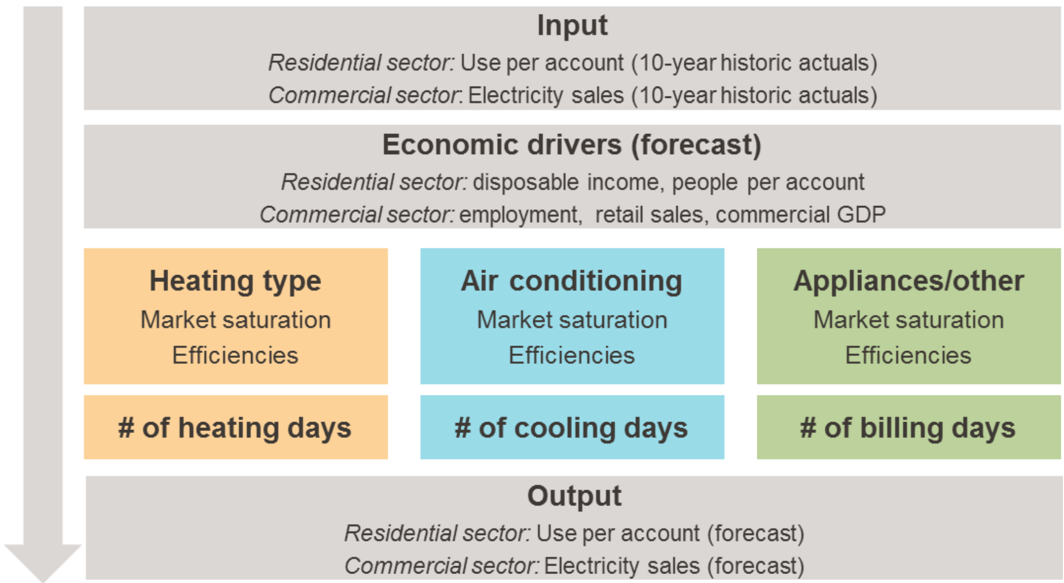
Step 1 - Number of Accounts: As with the forecast used in the Previous Application, to calculate the growth in the number of accounts the four regions are further divided into 15 sub-regions. The accounts themselves are also divided into single family dwelling accounts and multiple family dwelling accounts, respectively. The number of accounts forecast using this breakdown is based on a housing forecast from the Conference Board of Canada, June 2018 Economic Forecast. Our new method of forecasting accounts employs a ratio that translates housing projections into a number of residential customer accounts. The ratio has been updated (as discussed in section 3.2.6.2) to reflect current data.

Step 2 - Use Per Account: As with the forecast used for the Previous Application, the use per account forecast employs SAE regression models that establish a relationship between data and factors that influence the average use per account. The SAE models are products developed by ITRON (an energy forecasting consulting firm) and sold to BC Hydro. BC Hydro then adapts and populates the model with BC Hydro's customers' historical data and inputs. BC Hydro maintains full care and control of all customer information and it is never provided to a

80 The terms in this figure are defined within the process steps of the main text. While not shown in the Figure 3-4 and Figure 3-7, load reductions rate impacts, DSM savings, and savings from loss reductions.

third-party. SAE models are commonly used by utilities across North America and are considered to be an industry best practice, as highlighted in the Load Forecasting Audit. Figure 3-5 provides a conceptual overview of our implementation of the ITRON SAE models.

Figure 3-5 Illustrative Summary of SAE Model[81]



We use a single SAE model like this to forecast the average use per account for the each of the four residential regions.

The residential SAE models are called statistical regression models because they involve a set of statistical processes for estimating the relationships among variables. In the case of our residential forecasts, the SAE models identify the relationships between use per account and the following variables over the most recent 10-year history (model calibration period) ending in fiscal 2018:

- Consumer preferences and average efficiency of electricity end-uses;
- Temperature variables;

[81] Figure 3-5 is an illustrative summary of inputs, economic drivers, and outputs for both residential and commercial sector models.

- People per household; and
- Disposable incomes.

Using the relationships established from the model calibration period of the past ten years of data, the models then generate forecasts of future electricity use per account based on our expectations of future electricity end-uses, people per household, disposable incomes, and average temperature conditions. The future electricity end uses are developed with a combination of our own recent end use survey data and recent data from the US Energy Information Administration (**EIA**).

Step 3 - Adjustment to avoid double-counting: Once the SAE models produce results, an adjustment is made to account for the fact that there is an overlap between savings included in our SAE models' results and savings derived from our DSM Plan that are included later in the process. This overlap results because there are energy savings from codes and standards that are reflected in both our DSM Plan and the US EIA assumptions included in the SAE model. An example of a standard is an appliance minimum efficiency standard. We adjust the SAE models' results to mitigate potential double counting by using an estimate of the overlap between the SAE models and our DSM plan.

Step 4 - Add loads not accounted for in the SAE model: These include:

- **Electric vehicle load allocated to the residential sector**: Electric vehicle load is estimated from BC Hydro's electric vehicle forecast model. The residential sector is allocated 85 per cent of the electric vehicle model's results. The allocation is based on recent data on electric vehicles from ICBC.
- **Fuel switching load**: New loads when customers convert from a non-electric source of energy to electricity. We forecast fuel switching based on specific government or BC Hydro programs that incent customers to switch from fossil fuel-based energy to clean electricity. A summary of BC Hydro's Low Carbon

Electrification Program is found within Appendix Y, while the amounts for fuel switching by customer sector are listed in Appendix O.

Step 5 – Subtract loads for various reasons: The final step to complete the Residential Sector Load Forecast is to account for three other sources of load reductions:

- **Rate impacts:** Load reductions estimated using price elasticity and bill impact projections in real dollars (net of inflation). The bill impact projections reflected in the October 2018 Load Forecast are based on the last five years of the 2013 10 Year Rates Plan. Price elasticity is the impact of future electricity rate increases on customer demand. Price elasticity is expressed as the per cent change in quantity to a one per cent change in electricity price.
- **Loss reductions:**[82] Load reductions to account for efficiencies at BC Hydro's distribution substations to improve voltage levels to minimize line losses resulting in energy savings. These reductions are relatively small amounts over the test period.
- **DSM savings**: Load reductions to account for our DSM Plan. Further details on BC Hydro's DSM Plan are described in Chapter 10, section 10.1.2.
- The aggregated results constitute the Residential Sector Load Forecast.

3.2.6.2 Improvements to the Residential Sector Methodology

BC Hydro has made the following methodology improvements to the Residential Sector Load Forecast:

- **Recalibrated residential account growth relationship to housing starts:** We updated our approach to forecasting account growth. Previously, the methodology assumed that growth in the number of accounts was correlated

[82] Loss reductions were referred in the Previous Application as Var and Voltage Optimization (**VVO**) savings. Loss reductions are applied to residential, light industrial and commercial customers.

with housing growth on a 1:1 basis. However, a review of recent data indicated this is not the case. We have replaced the 1:1 ratio of residential accounts to every unit of housing with a ratio of 0.9:1, which is the average ratio indicated by our data.

- **Updated customer response to temperature:** We reviewed the relationship between temperature and residential use per account using smart meter data. The objective of this review was to examine the average temperature at which sales begin to increase in response to colder temperatures (generally associated with use of electric heating). We conducted a similar update looking at the average temperature at which sales begin to increase in response to warmer temperatures in the summer months (generally associated with air conditioning). Our review found that our previous approach of using a single temperature of 18°C as the point at which customers respond to outside temperatures could be improved. We now model multiple temperature thresholds, which has enabled the development of more statistically sound SAE models. For example, for the residential load in the Lower Mainland we found there is a response to colder temperatures at 15°C and 3°C. For the largest segment of commercial load in the Lower Mainland we found there is a response to colder temperatures at 12 °C and 3°C.

- **Recalibrated the relationship between economic variables and electricity sales:** In response to the Load Forecasting Audit recommendations mentioned previously, we reviewed and updated relationship coefficients between economic variables, such as disposable income, and use per account for all residential SAE models.

- **Adjusted our price elasticity assumption:** The need to review and update our price elasticity assumption was a finding from the Load Forecasting Audit, the Previous Application’s proceeding as well as the Site C Inquiry. In March 2018, BC Hydro retained DNV GL to conduct an electricity price elasticity study for each of our customer sectors. DNV GL is a global quality assurance and risk management company, with a highly regarded energy advisory services division offering institutional, legal and technical expertise on electricity systems. The company has global operations in over 100 countries. The results of their price elasticity study are included as Appendix Q (Elasticity Study & GDP Study).

DNV GL's key findings, which were adopted for this forecast, included:

- "In our survey, the most commonly reported price elasticity for the residential sector is -0.10. While values as low as -0.06 and as high as -0.26 are in use among the utilities we reviewed, the most commonly reported value is a useful indicator of typical consumer response to rate changes. The -0.10 value is also most commonly reported for the two other sectors. Further, this value (-0.10) was recently recommended in an expert testimony to the Manitoba Public Utilities Commission presented in the table above."
- "Values from external sources as well as those determined by BC Hydro from its own and neighbouring utility data, indicate a residential price elasticity value that centres around -0.10 is a reasonable value for BC Hydro's residential customers. Therefore, we recommend that BC Hydro increase the price elasticity in use to assess rate impact and determine load forecast growth for the residential customers. Based on the convergence of values, we find an increase to -0.10 to be reasonable."
- "Recommendation: In general, we find BC Hydro's application of price elasticity to be consistent with that of many of the Canadian and U.S. utilities we reviewed. DNV GL supports the continuation of BC Hydro's approach to load forecasting which involves building up sector specific forecasts, including site-specific large commercial and industrial forecasts, and applying a single price elasticity to account for price changes in the forecast. Given that

> BC Hydro employs a site by site assessment for industrial facilities which captures price effect for a selection of energy intensive facilities, such as pulp mills; and precedent elsewhere, of applying the same price elasticity across all three sectors, we recommend that BC Hydro continue to use the same price elasticity estimate for all sectors. The actual elasticity value will depend on whether BC Hydro adopts the weighted average elasticity from its 2016/17 Residential Inclining Block (**RIB**) evaluation (-0.09) or the recommended -0.10 price elasticity estimate from our research and expert recommendations".

The DNV GL study results, combined with the results of our own evaluation of the residential inclining block rate (fiscal 2013 to fiscal 2017), supports the results of our previous internal studies and third party assessments that our price elasticity estimates are consistent with what is commonly reported and on the lower end of the survey data.

For this forecast, BC Hydro has increased the electricity price elasticity value used for all of the main customer sectors in the Load Forecast for this application from -0.05 to -0.10. The impact of changing the elasticity, all else equal, results in a small net change to the total Load Forecast of about 21 GWh in fiscal 2020 and about 37 GWh in fiscal 2021.

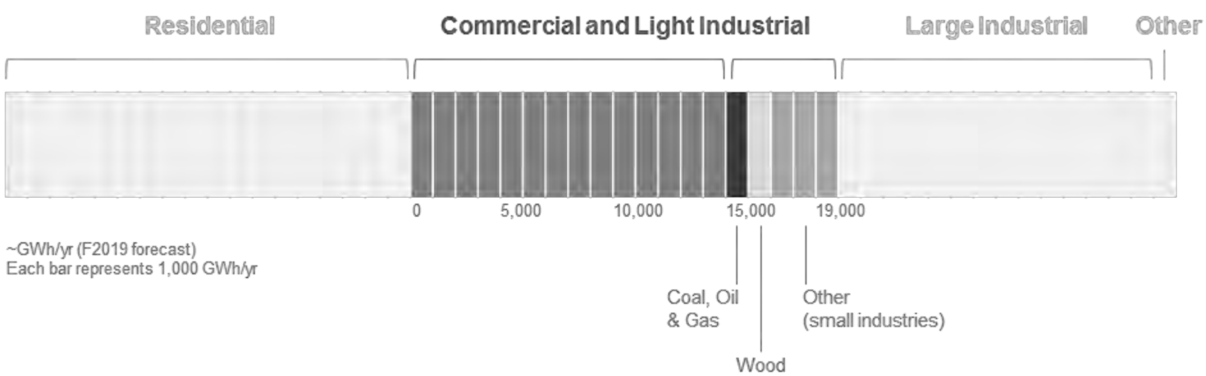
3.2.7 Commercial and Light Industrial Sector Methodology Has Been Improved

The commercial and light industrial sector consists of approximately 210,700 accounts and represents approximately one-third of total electricity sales. The forecast for this sector consists of two customer groups connected at distribution voltages:

- **Commercial Sector:** This sector includes customers such as office buildings, retail stores and warehouses. It represents approximately 80 per cent of sales to the commercial and light industrial sector.

- **Light Industrial Sector:** This sector includes small and medium sized forestry, oil and gas and coal mining operations, and other light industrial loads from various sectors including manufacturing, agriculture, etc. It also includes incremental cannabis and cryptocurrency loads receiving distribution service. It represents approximately 20 per cent of sales to the commercial and light Industrial sector.

Figure 3-6 Commercial and Light Industrial Sector Relative to Overall Load

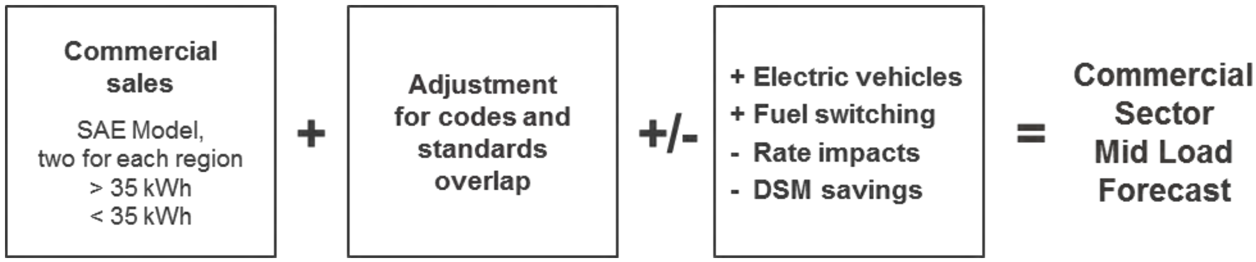


The Commercial and Light Industrial Forecast retains the same basic methodology. However, we have made improvements to the model.

3.2.7.1 Commercial Sector Methodology Uses Standard Modelling Techniques

The Commercial Load Forecast is an aggregation of forecasts developed for each of four service regions: the Lower Mainland, Vancouver Island, South, Interior, and the North Region. As with the residential sector, and consistent with the forecast prepared for the Previous Application, an SAE modelling approach is used. Within each region, separate SAE forecast models are used for small commercial customers (below 35 kW) and large commercial customers (above 35 kW). Figure 3-7 illustrates the process of developing the Commercial Sector Load Forecast.

Figure 3-7 Commercial Sector Load Forecast Methodology



While the residential sector uses the SAE model to forecast use per account, our commercial sector SAE models estimate commercial sales directly. The different approach for the commercial sector is because:

- We have not identified an economic driver that provides a reasonably accurate predictor of commercial account growth; and
- There are practical limitations given the greater diversity that exists within the commercial sector. This diversity creates additional complexity in developing a forecast process that estimates intensity, efficiency, and square footage of all the building types that exist across the various commercial segments.

The models use statistical regression to establish relationships between commercial sales, major commercial electricity end-uses, temperature variables and economic variables over the most recent ten-year history (model calibration period). The models then forecast future sales based on forecasts of economic variables (commercial GDP, employment, retail sales), the recent U.S. EIA forecasts for future end-use average efficiency trends and share of commercial electricity equipment and temperature conditions based on a historical average (as is the case in the residential SAE model). Similar to the residential sector, SAE modeling is considered by the audit findings to be the "best approach for modeling commercial sector sales". As referenced in section 3.2.6.1, Figure 3-5 provides a simplified conceptual representation of the SAE models showing the inputs used in the commercial model as well as the residential models.

As shown in Figure 3-7, and consistent with the development of the Residential Sector Load Forecast, to develop the Commercial Sector Forecast we follow these additional steps:

1. We make an adjustment to avoid double counting the impact of codes and standards between the SAE model and our DSM Plan savings, as described for the residential forecast in section 3.2.6.1.
2. Loads which are not accounted for in the SAE models are added. These include a) electric vehicle loads - the commercial sector is allotted 15 per cent of BC Hydro's electric vehicle forecast, with the remainder included in the residential forecast; and b) fuel switching loads as they relate to this sector.[83]
3. Loads are reduced to account for rate impacts and DSM savings.

The aggregated results constitute the Commercial Sector Load Forecast.

3.2.7.2 Improvements to the Commercial Sector Methodology

Improvements made to this sub-sector were similar to the SAE model-related improvements from the Residential Sector Load Forecast listed in section 3.2.6.2. These include:

- Updated customer response to temperature;
- Recalibrated relationship of economic variables to electricity sales based on an updated 10-year model calibration period; and
- Updating price elasticity from -0.05 to -0.10, consistent with the results of the independent elasticity study.

[83] Estimates based on the Government of B.C.'s and BC Hydro's low carbon electrification programs which encourage fuel switching from fossil fuels to electricity. These adjustments apply to all sectors and they are relatively small over the test period.

3.2.7.3 Light Industrial Sector Methodology Incorporates Tailored Methods

The light industrial sector represents a relatively small component of the overall load forecast (8 per cent). The sector consists of approximately 30,000 customers in a diverse range of industries. As such, a variety of forecasting methods are used, ranging from account-by-account forecasts, regression models, and production intensity based methods. These industrial sub-sectors and descriptions of their forecast methods are listed below:

- **Coal Mining:** The forecast is determined on an individual customer account basis in similar manner to the large industrial coal mining customers outlined in the mining summary in section 3.2.8.1.
- **Forestry:** Customers in this sub-sector are sawmills, panel mills and pellet plants. The forecast for this sub-sector is determined by developing mill by mill production forecasts, aggregating those forecasts by region and then multiplying the total by the historical electricity use intensity for each region and mill type.
- **Oil and Gas:** Customers in this sub-sector are primarily production and processing, transport (pipelines, pump stations, truck terminals, etc.) and support services for the oil and gas industry. The forecast is primarily determined on an individual customer account basis outlined in the oil and gas summary in section 3.2.8.1.
- **Other Light Industrial:** Sales for this sub-sector are primarily forecast using a regression model built on the historical relationship between sales to these customers and provincial GDP. The inputs to the regression model to determine the sales forecast is the short-term GDP forecast from the B.C. Ministry of Finance. Then, additional industry loads are added:
  - Cannabis and Cryptocurrency: as emerging industries, the forecast is developed with customer requested loads that are considered highly

probable based on their advanced stage of progress in BC Hydro's interconnection process; and

- Load expected to power the construction of LNG plants and other facilities. These construction loads are separate from plant operational requirements.

Two further steps are undertaken for the light industrial sector forecast, including:

1. Fuel switching load estimates are added to the sector as a whole.
2. Estimated load is reduced to account for rate impacts and DSM savings.

The end result is BC Hydro's Light Industrial Sector Load Forecast.

3.2.7.4 Other Changes to the Light Industrial Sector Methodology

Price elasticities were revised from -0.05 to -0.10 as discussed in section 3.2.6.2

3.2.8 Large Industrial Sector Methodology Has Been Improved

BC Hydro has approximately 190 large industrial customers which represent approximately 26 per cent of total sales. Customers in the large industrial sector are categorized into the same sub-sectors as light industrial customers (mining, forestry, oil and gas, and other large industrial customers) shown in Figure 3-8. While light industrial customers are connected at distribution voltage, large industrial customers are connected at transmission voltage.

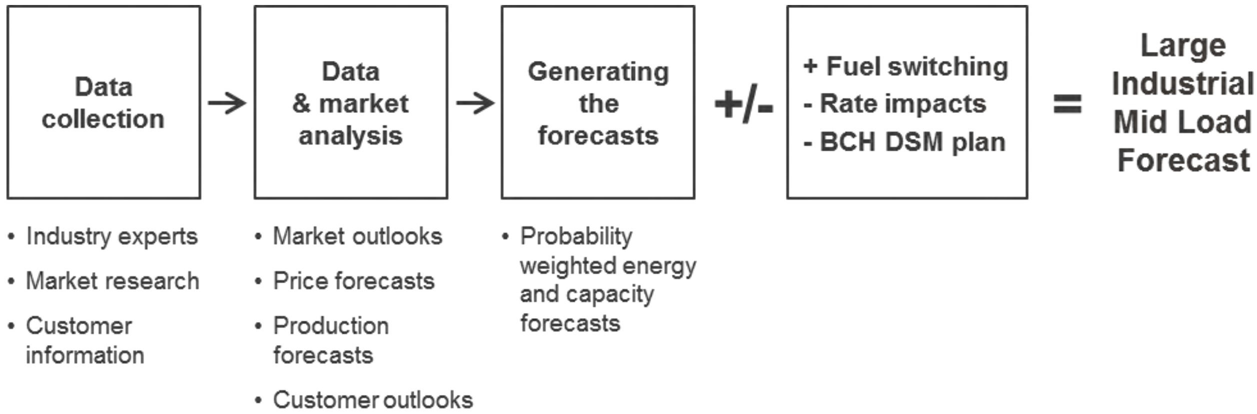
Figure 3-8 Large Industrial Sector Relative to Overall Load

As in prior years, sales to the large industrial sector are forecast on an individual customer account basis. While we continue to follow this approach, a number of methodological improvements have been made in areas identified in the Decision to the Previous Application and the Site C Inquiry.

3.2.8.1 Account by Account Approach Remains Appropriate

The account-by-account process that we use to produce the Large Industrial Sector Load Forecast is shown in Figure 3-9.

Figure 3-9 Preparing the Large Industrial Sector Load Forecast



We develop the Large Industrial Sector Load Forecast using information from several sources. These include:

- **Industry experts:** BC Hydro retains external consultants who develop production and commodity price forecasts and provide facility and/or sector-specific market assessments.
- **Market research:** BC Hydro subscribes to a number of services from companies that provide market research and industry analyses. BC Hydro also relies on various publically available reports from government agencies, such as the BC Oil and Gas Commission.
- **Information from our customers:** BC Hydro uses customer-specific information gathered by our Key Account Management and Load Interconnections groups, who are in direct contact with our customers.

Using these sources of information, we develop a probability weighting for expected sales to our current customers. This probability weighting represents a risk assessment of the likelihood of future sales increasing, decreasing or remaining steady.

For each potential new customer, these same sources of information are used to develop similar probability weightings to forecast if and when new demand will materialize.

Each of these probability weightings represents our professional judgement based on a synthesis of information from the sources listed above. Some of the factors that are considered when assigning probability weightings include:

- How far a customer has passed through our interconnection processes;
- The status of the customer's regulatory/approval permits and project financing;
- BC Hydro's ability to meet the customer's requested in-service date;
- Consultant mill and market assessments, where applicable;
- The market outlook for the customer's products;
- The credit and financial viability of the customer;
- The impact of electricity costs on the customer;[84] and
- The likelihood that the customer will take electricity supply from BC Hydro instead of self-supplying their power needs.

Due to commercial sensitivities, individual account assessments are kept confidential. To maintain this confidentiality the large industrial forecast is aggregated by sub-sector.

The following provides a summary of the main drivers of electricity sales in each of the large industrial sub-sectors:

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[84] This factor incorporates the impacts of future electricity costs on electricity demand relative to how much their electricity costs are to overall cost of production on a sub-sector wide basis. This is separate from, but needs to be considered along with, price elasticity when assessing the overall impacts of future electricity prices.

- **Mining:** The mining sub-sector includes both metal and coal mining operations. It represents approximately 29 per cent of sales to the large industrial sector. Sales to the mining sector depend on global commodity prices which are driven by economic growth within parts of Asia, such as China, as well as the supply and demand outlooks for copper, gold and coal. Other factors that impact mining sales and sales to other industrial sub-sectors, include the availability of financing, regulatory and environmental approvals and First Nations considerations.
- **Forestry:** The forestry sub-sector includes pulp and paper, wood products and chemical segments. It represents approximately 51 per cent of the total large industrial sales. Sales to the pulp and paper segment depend on global pulp prices, B.C. fibre supply, the demand for paper products (such as newsprint, packaging and speciality coated papers), and the cost competitiveness of B.C. pulp and paper mills. Sales to the wood segment depend on the U.S. housing market, global wood products supply and demand drivers, and the supply and demand of B.C. wood fibre. Sales to the chemical segment are linked to B.C. demand (pulp and paper, water purification and industrial cleaning) and the opportunity for exports.
- **Oil and Gas:** The oil and gas sub-sector currently makes up approximately 11 per cent of total large industrial sales and includes:
  - Natural gas and natural gas liquids production and processing (i.e., primarily shale gas, but also conventional gas);
  - Oil (and condensate) pipelines;
  - Oil refineries and oil producers;
  - Natural gas pipelines;
  - Propane terminals; and
  - LNG terminals.

- Sales to the oil and gas sector depend upon commodity price outlooks for oil, natural gas, natural gas liquids, and LNG; the competitiveness of B.C. oil and gas producers, and the operational environment. The relative cost of natural gas and electricity is a significant factor when forecasting electricity sales to this sub-sector since it influences the likelihood that customers will take electricity service from BC Hydro rather than self-supply their power needs with natural gas.
- **Other Large Industrial**: This sub-sector makes up approximately 9 per cent of total large industrial sales and includes customers connected at transmission voltage not captured by the other large industrial sub-sectors mentioned above. Examples of customers include airports, seaports, universities and cement operations. This sub-sector also includes cannabis and cryptocurrency loads connected at transmission voltage instead of distribution voltage. The drivers of electricity sales in this sub-sector vary by customer.

BC Hydro makes load additions and reductions similar to those made for the residential and commercial and light industrial sectors. Specifically, load from fuel switching is added. Load reductions are then applied for rate impacts, loss reductions and DSM savings.

The aggregated results constitute the Large Industrial Sector Load Forecast.

3.2.8.2 Improvements to the Large Industrial Sector Methodology

We made improvements to the Large Industrial Sector Load Forecast methodology. These improvements specifically address, but also go beyond, issues raised by the BCUC and the Load Forecasting Audit:

- **LNG:** We updated our methodology for forecasting sales to LNG customers. In the Site C Inquiry Final Report, the BCUC observed that “BC Hydro has not made a probabilistic assessment of the likelihood of the LNG load materializing."[85] In this application, we forecast sales to LNG customers in a manner consistent with other large industrial customers: using the probabilistic assessment approach outlined in the Large Industrial Sector Methodology section and discussed in the next bullet.

- **Probability Weightings:** As part of our ongoing internal efforts to improve our load forecast methodology, we changed how we incorporate individual customer probability assessments into the first three years of our Large Industrial Sector Load Forecast (fiscal 2019 to fiscal 2021).

Previously, a customer's load was adjusted by the probability weighting we assigned to it over the forecast period. The probability weightings reflect a number of risk factors, including the likelihood that customers will expand, contract or maintain operations; close operations; or start new operations (e.g., in the case of new customers). A review of our fiscal 2018 Load Forecast variance showed a significant positive variance (higher actual loads relative to forecast) and negative variance (lower actual loads relative to forecast) for several industrial sub-sectors, notably forestry (positive variances) and oil and gas (negative variances). These variances were determined to be attributed to risk adjustments (i.e., probability weightings) on specific customers that were significantly driven by closure risk considerations (for some existing customers) or start-up likelihood consideration (for new customers). For example, a customer with a 25 per cent probability of closure would have their anticipated load included in a load forecast at 75 per cent. Operationally, the net effect of facility closures or start-ups is that a facility will either be fully operational (i.e., on) or not operating at all (i.e., off). However, the net effect of reflecting those "on/off" risk adjustments in the load forecast results in partial loads. It is the difference between those partial loads reflected in the forecast and actual operations being either "on" or "off" which largely explains the recent industrial sub-sector load forecast variances.

[85] BCUC Final Report with Respect to the Site C Inquiry (November 1, 2017), page 78.

In order to address this issue, BC Hydro has moved to a binary approach for the first three years of the forecast. The binary method results in a discrete projection (i.e., in or out) of load and revenues. This approach is applied as follows:

- We continue to undertake probability assessments on an individual customer account basis.
- Where the dominant risk factor amongst all others is closure risk, customer loads included in the forecast are reflected at either their full expected load (weighted at 100 per cent probability) or zero load (weighted at 0 per cent) for the period fiscal 2019 to fiscal 2021, depending on whether the closure risk is assessed as being low or high.
- Where the main risk factor is start-up likelihood, only high likelihood projects are included at their full expected load in the period fiscal 2019 to fiscal 2021. For these highly likely projects we also consider project schedule risk as part of the binary assessment. For example, there may be uncertainty on when a project actually comes into service relative to the customer requested in-service date. In these situations we will exercise our professional judgement in deciding whether to reflect the full expected load at a later date than that requested by the customer. If we determine that there is a reasonable likelihood the actual in-service date will occur beyond the customer requested in-service date, the full expected load (i.e., weighted at 100 per cent) will be reflected at that later date in the forecast and at zero load (i.e., weighted at 0 per cent) prior to that date.

On an aggregate sector total basis, this binary approach may or may not improve load forecast accuracy over the test period since positive variances in one sub-sector may offset negative variances in another. However, we believe this approach will improve load forecast accuracy for specific segments since it addresses why the most recent variances occurred. Over the long- term, we believe a probabilistic based approach continues to be the best method for developing the large industrial sector forecast on an aggregate basis. Our view is supported by our load forecast audit findings.

- **New Consultant Services:** Previously we had not relied on external subject matter experts to provide a comprehensive analysis of B.C. shale gas development. However, for this forecast we recognized the shale gas segment of the oil and gas sub-sector as the fastest growing area of our sales, and retained the services of an oil and gas consulting company. Their Western Canadian expertise served to provide industry intelligence to improve the accuracy of our assumptions, with a focus on:
  - Montney shale gas development in B.C. and individual customer well plant property evaluation (to improve new plant probability weightings and reduce load forecast uncertainty);
  - Oil and gas and gas liquids price forecasting; and
  - Oil sands development (which will consume much of B.C.'s natural gas and gas liquids).
- **Price elasticity:** As in the other sectors, price elasticity was updated from -0.05 to -0.10 as discussed previously in section 3.2.6.2.

3.2.9 Other Sector Methodology Incorporates Tailored Methods

The Other sector currently represents approximately 3 per cent of the total sales demand in the Load Forecast. Demand in this sector comes from irrigation and street light customers, sales to other inter utility sales (City of New Westminster and FortisBC Electric), and firm exports (Seattle City Light and Hyder). Specifically:

- **Irrigation and Street Lighting**: The forecast is based on historical growth trends. BC Hydro is in the process of approving its business case to replace street lights with LED technology. The potential roll-out of this program will not have a material impact on the total load and revenues during the test period (expected to be about 20 GWh/year), but will be monitored for impacts to future load forecasts.

- **FortisBC Electric**: The forecast is based on information provided by FortisBC Electric as well as projections from our internal model that considers the forecast of electricity market prices relative to the cost of purchases from BC Hydro under Rate Schedule 3808.
- **The City of New Westminster**: The forecast is based on historical load as well as information provided by the City of New Westminster regarding new residential and commercial loads.
- **Seattle City Light**: This forecast is determined by the Skagit River Valley Treaty which prescribes sales of approximately 310 GWh per year.
- **Hyder, Alaska:**[86] The forecast is based on historical load.

Load reductions are then applied for rate impacts. However, this step does not apply to Seattle City Light's or FortisBC Electric's loads. Sales to Seattle City Light loads are established under the Skagit River Valley Treaty. As such, there is no rate to which Seattle City Light revenues and sales are calculated. Sales to FortisBC Electric have the elasticity impact implicitly built into the methodology. The methodology considers the cost of purchases from BC Hydro which are subject to rate increases versus the cost of purchases from the market.

The aggregated results constitute the Other Sector Load Forecast.

3.2.9.1 Changes to the Other Sector Methodology

Price elasticities were revised from -0.05 to -0.10 across all customers in this sector, except for Seattle City Light and FortisBC Electric for the reasons described above.

[86] Also referred to Tongass Power in BC Hydro's Revenue Forecast in section 3.4 and Appendix A, Schedule 14.

3.2.10 Aggregating the Load Forecast and Establishing Uncertainties: The Mid Forecast with Low and High Bands

There is uncertainty in forecasting, which is accounted for by using a band around the Mid Load Forecast. The band is developed using a recognized statistical methodology that was endorsed in the recent audit.

3.2.10.1 There Are Several Sources of Uncertainty Reflected in the Band

Our Mid Load Forecast for the test period is an aggregation of the individual sector forecasts, including an adjustment for codes and standards overlap, as well as further load additions and load reductions.

The mid forecast prior to DSM savings is developed by analyzing and modeling the relationships between energy sales and the predictors of future sales, which are referred to as load drivers. Drivers consist of both economic variables and non-economic variables. Economic variables include GDP, housing starts, retail sales, employment, commodity production and commodity prices. Non-economic variables include temperature and average stock efficiency of various electricity end-uses. All of these load drivers are themselves forecasts and these forecasts lead to increases or decreases in electricity sales.

There are also uncertainties associated with the various models used to develop load forecasts, such as the accuracy of using statistically determined relationships between drivers and load to forecast loads at a point in time where the nature of those relationships may be changing. Understanding the changing relationships between economic drivers and electricity demand is challenging many North American utilities.

3.2.10.2 The Recent Audit Endorsed Monte Carlo Analysis

To address load forecast uncertainty, BC Hydro produces low and high uncertainty bands using Monte Carlo simulation analysis. The uncertainty bands produced by the Monte Carlo analysis are before DSM savings. The Monte Carlo analysis involves the sampling of distributions for key load uncertainty variables such as temperature (i.e., heating degree days), economic activity (i.e., GDP), electric vehicles, and distributions of sales for each of the large industrial sub-sectors. The distribution of sales for these sub-sectors includes the expected forecast as well as discrete low and high sub-sector forecasts. The Load Forecast Audit confirmed that simulation analysis is the best approach for developing uncertainty bands since it is statistically based, can include multiple input variables, and produces a probabilistic forecast based on input probability distributions.

To demonstrate the range of forecast uncertainty, we use the p-90 and p-10[87] forecast outcomes from the probability distribution of all possible forecast outcomes that center around our mid forecast before incremental DSM. Given the p-90 and p-10 forecast outcomes, the range of uncertainty represents an 80 per cent confidence interval.

As discussed above, our Mid Load Forecast is our expected sales after adjusting for codes and standards overlap, load additions (e.g., electric vehicle load), DSM, rate impacts and loss reductions. The uncertainty bands produced by the Monte Carlo analysis are before incremental DSM. More information on DSM savings is provided in Chapter 10, section 10.5.

3.2.11 BC Hydro’s Methodology Compared Well Against an Alternative Methodology

In the Decision from the Previous Application, the BCUC noted that “other utilities such as Pacific Northern Gas Ltd., FortisBC Energy Inc., and FortisBC Inc. use a different load forecast methodology for their short term forecast for setting rates as compared to its long term forecast for resource planning.”[88] In light of the BCUC’s

[87] P-10 means there is a 10 per cent chance that forecast outcomes will be below the values shown as the p-10. P-90 means that there is a 90 per cent chance that forecast outcomes will be below the value shown as p-90.

[88] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), Appendix B, page 11.

observation, we reviewed the other utilities' short-term forecast methodologies and developed an alternative forecast based on the methodology used by FortisBC Inc., the other major electric utility in B.C.

Results of our alternative forecast comparison showed BC Hydro averaged a billed sales variance of -0.3 per cent (residential sector) and -0.4 per cent (commercial sector) for fiscal 2016 to fiscal 2018 using our load forecasting methodology, while the average billed sales variance using FortisBC Electric's methodology was 2.4 per cent (residential sector) and 0.8 per cent (commercial sector) for the same time period.

Considering the recent performance of our own methodology, the results of our comparison using an alternative short-term forecast methodology, and the improvements outlined previously that we made, we concluded that it was appropriate to use our forecast methodology for this Load Forecast.

3.2.11.1 The Recent Strong Performance of BC Hydro's Methodology Makes Outperformance Difficult

As described above, actual sales since May 2016 have closely tracked our May 2016 Load Forecast used in the Previous Application. The total load variance for fiscal 2017 was 0.1 per cent within forecast and for fiscal 2018 was 0.5 per cent within forecast. Further variance analysis information is available in Appendix G, section 2 (Variance Explanations).

3.2.11.2 Residential and Commercial Forecasts Are the Main Differences from FortisBC

Although we reviewed the short term-load forecast methodologies of FortisBC Energy Inc. (gas operation), FortisBC Inc. (electric operations), Pacific Northern Gas West Ltd. (gas operations), and Pacific Northern Gas Northeast Ltd (gas operations), we focused on FortisBC Inc.'s (**FortisBC Electric**) electric load forecast as a potential alternative methodology, since FortisBC Electric is the other major regulated electric utility in BC.

Table 3-2 below compares BC Hydro's existing load forecast methodologies to the FortisBC Electric methodology by customer sector. The mechanics of BC Hydro's and FortisBC Electric's large industrial sector methodologies are substantially the same. However, the methods each utility uses to develop their residential and commercial sector load forecasts are different. BC Hydro's residential and commercial sector methods incorporate a larger set of economic and end-use efficiency variables that can impact load compared to FortisBC Electric.

Table 3-2 Comparison of BC Hydro's Existing and FortisBC Electric's Short-Term Load Forecast Methodologies

Sector	BC Hydro	FortisBC Electric
Residential	A SAE model is used to forecast average use per residential account in each of BC Hydro's four major service regions. Refer to section 3.2.6.1 for more information on the SAE model. The accounts forecast is based on historical ratio of account growth to housing growth and housing growth forecasts, which are provided by the Conference Board of Canada.	The forecast of average use per account is established with a three year historical trend line of temperature-normalized use per account. The time trend is assumed to continue into the future to develop the forecast. The accounts forecast is based on a regression of historical accounts and population statistics which are provided by BC Statistics.
Commercial	SAE models are used to forecast electricity sales for both small commercial customers and large commercial customers in each of BC Hydro's four major service regions. Refer to section 3.2.6.1 for more information on the SAE model.	The commercial sector forecast is based on a regression analysis of load to provincial GDP. The GDP forecast is provided by the Conference Board of Canada.

Sector	BC Hydro	FortisBC Electric
Large Industrial	BC Hydro has approximately 190 large industrial customers, and forecasts load for this sector on an account by account basis. Forecast load for each account is developed using a probabilistic assessment of future customer sales. This assessment relies on intelligence from external consultants who are industry and/or plant experts, as well as third-party market subscription services. The assessment also relies on information provided by BC Hydro's key account managers who liaise directly with our customers. Based on the probability weighting for each customer, BC Hydro makes "in or out" call on the viability of each account for the test period years. This methodology is explained in more detail in section 3.2.8.	FortisBC Electric has approximately 50 industrial customers. Forecast load for these customers is developed based on confidential updates shared by customers through surveys conducted by FortisBC Electric. Where customer information is not available, FortisBC Electric applies GDP growth rates to each of its customers.

We used FortisBC Electric's short-term methodology to generate a load forecast from fiscal 2016 through fiscal 2018 to compare against our May 2016 Load Forecasts used in the Previous Application for the residential and commercial sectors. The results showed that our variance on average is more favorable compared to the average variance when we developed a load forecast using the FortisBC Electric's methodology applied to same input data used in the May 2016 Load Forecast. Specifically, BC Hydro averaged a billed sales variance of -0.3 per cent (residential sector) and -0.4 per cent (commercial sector) for fiscal 2016 to fiscal 2018 using our load forecasting methodology. The average billed sales variance using FortisBC Electric's methodology was 2.4 per cent (residential sector) and 0.8 per cent (commercial sector) for the same time period.

3.3 Load Forecast Results

The results of the Load Forecast are described in aggregate and then by customer sector in sections 3.3.1 through 3.3.5, with the risks and uncertainties that accompany the results outlined in section 3.3.6. As discussed below, BC Hydro is forecasting more modest growth relative to the May 2016 forecast used in the Previous Application.

3.3.1 Overall Load Forecast Shows Only Modest Growth

Overall, the BC Hydro's Load Forecast shows demand for electricity is forecast to increase by approximately 650 GWh or 1.2 per cent from fiscal 2019 to fiscal 2021. The Load Forecast results are summarized for the test years in Table 3-3 and the years fiscal 2019 to fiscal 2023 in Figure 3-10.

Table 3-3 provides the three components of the Load Forecast: the Mid Load Forecast and low band and high band, which represent the range of demand uncertainty. For a discussion on the low and high uncertainty bands, refer to section 3.3.6.

Table 3-3 Electricity Sales Summary after Rates after DSM Savings

	Forecast[89] (GWh)	Forecast (GWh)	Forecast (GWh)
Residential	18,049	18,258	18,330
Commercial and Light Industrial	18,976	18,973	19,030
Large Industrial	14,003	14,702	14,243
Other	1,575	1,634	1,650
Low Band	51,716	52,244	51,364
Mid Load Forecast[90]	52,604	53,567	53,253
High Band	53,507	54,907	55,189

Characterizing the Load Forecast using the Mid Load Forecast as an anchor, it shows a total increase in electricity sales by approximately 650 GWh over the test period. However, that growth is not linear with:

- Forecast demand increasing from fiscal 2019 to fiscal 2020 by approximately 960 GWh, driven primarily by growth in the oil and gas sub-sector and residential sector; and then

[89] Mid Load Forecast for fiscal 2019 includes six months of actuals, and six months of forecast data.

[90] Electricity sales do not include line losses or sales to BC Hydro. This is captured in Total Domestic Sales as show on line 14 of Schedule 4 of Appendix A.

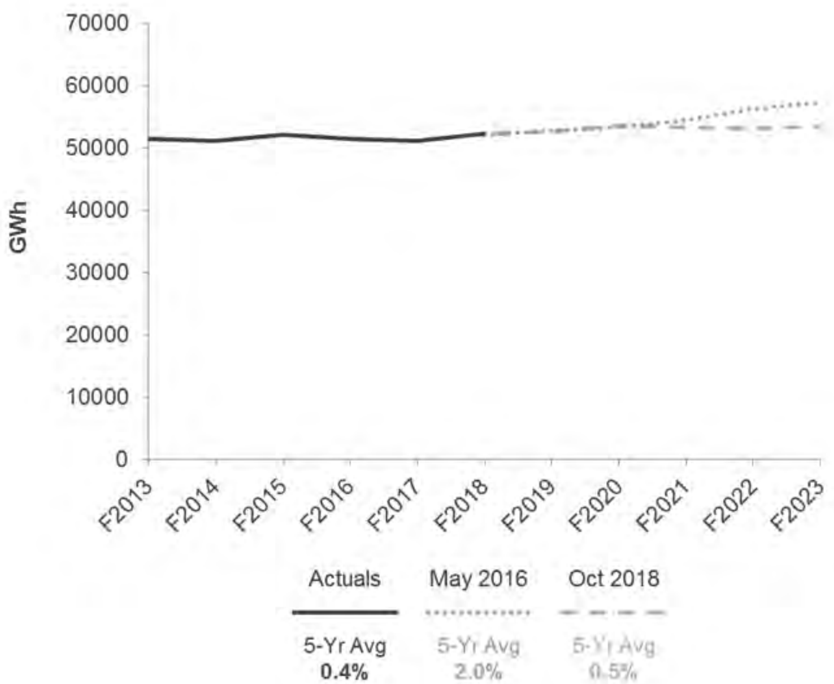
- Forecast demand declining from fiscal 2020 to fiscal 2021 by approximately 310 GWh. This decrease comes substantially from an expected decline in sales to the pulp and paper sub-sector in line with historical trends.

Figure 3-10 provides a summary of comparison between the October 2018 Load Forecast and the May 2016 Load Forecast for fiscal 2018 to fiscal 2023. It shows that over this period, the October 2018 Load Forecast's growth is a more moderate 0.5 per cent per year compared with the May 2016 Forecast of 2 per cent per year.

The October 2018 Load Forecast is growing slower than May 2016 Load Forecast because of changes in factors that impact load growth in the residential and commercial sectors which make up two thirds of our of total load. The lower forecasts for these sectors reflects the impact of a slower growth in the economic forecast, the recalibration of relationships between economic variables and electricity sales, and updated (i.e., higher) efficiency projections of various end uses of electricity and revised calibration period used in estimating the SAE models.

The slower growth in the residential sector and decline in commercial sector sales do not offset the increase in large industrial and light industrial sectors, as described below.

Figure 3-10 Electricity Sales Summary – October 2018 Load Forecast vs. May 2016 Load Forecast[91]



3.3.2 Residential Sector Load Forecast

The Residential Sector Load Forecast shows a total increase in demand of approximately 280 GWh over the test period. The increase in sales over the test period is primarily due to an expected increase in the number of residential accounts, increased estimated overlap in codes and standards, and increased load from electric vehicles.

The percentage growth in number of residential accounts shown in Table 3-4 equates to approximately 29,600 accounts between fiscal 2019 and fiscal 2020 and a further 24,400 accounts between fiscal 2020 and fiscal 2021. The forecast of accounts reflects a continuation of the strong growth in recent years in housing

[91] Figure 3-10 is the same as Figure 3-1, which was presented in section 3.1 (Introduction).

starts which is anticipated to continue over the test period as per the projections from the Conference Board of Canada, June 2018 Economic Forecast.

Table 3-4 Growth in Number of Residential Accounts

	F2017 Actual	F2018 Actual	F2019 Forecast	F2020 Forecast	F2021 Forecast
Annual Residential Account Growth[1] (%)	1.4	1.5	1.6	1.6	1.3

1. Residential accounts forecast and history is the number of accounts for all integrated and non-integrated customers.

The overall residential average use per account projection is expected to remain flat over the test period. As such, it is not a strong driver in the overall growth in sales over the test period.

In terms of the Electric Vehicle (**EV**) Load Forecast, Table 3-5 shows the contribution of electric vehicle load to the residential sector is expected to be about 89 GWh by the end of the test period. This equates to a forecast number of a total number of electric vehicles of approximately 24,300 in fiscal 2020 and 33,500 in fiscal 2021. The forecast of the number of electric vehicles and their associated load was developed using BC Hydro's in-house EV model. The EV model incorporates a number of drivers, such vehicle capital and operating costs, including incentives; as well as constraints, such as electric vehicle range and consumer adoption.

Table 3-5 Electric Vehicle Forecast – Residential Sector

	F2018 Actual[1]	F2019 Forecast[2]	F2020 Forecast[2]	F2021 Forecast[2]
Electric Vehicle Load[3] (GWh)	29	47	66	89

1. Actual residential EV load is based on percentages stated below.
2. Forecast is before reductions for rate impacts.
3. Total electric vehicle forecast split between residential (85 per cent) and commercial (15 per cent) sectors.

3.3.3 Commercial and Light Industrial Sector Load Forecast

Total electricity sales to the commercial and light industrial sector show an increase of 54 GWh between over the test period. This represents approximately 234 GWh decline in demand from the commercial sector and an increase of approximately 288 GWh in demand from the light industrial sector.

3.3.3.1 Commercial Sector Load Forecast

Over the test period, forecast sales to the commercial sector are expected to decline by about 234 GWh. This decline is a result of an update to the model calibration period, slower projected growth in economic drivers, increases in the efficiency of how commercial customers use electricity as well as the impacts of BC Hydro's DSM savings.

Forecasts of the economic factors that are inputs to our commercial SAE models are summarized in Table 3-6. They predict slower growth relative to the recent past, resulting in lower growth in commercial and light industrial sector demand.

Table 3-6 Economic Drivers of the Commercial Sector

Commercial Sales Drivers[1] (Annual Growth %)						
Economic Driver	F2016 (Actual)	F2017 (Actual)	F2018 (Actual)[1]	F2019 (Forecast)	F2020 (Forecast)	F2021 (Forecast)
Employment	1.3	3.1	3.7	1.5	1.2	1.4
Retail Sales	5.3	6.1	8.5	3.6	2.1	2.3
Commercial GDP	4.3	3.8	3.7	2.7	2.6	2.6

Notes:

1. The values are the actual and forecast growth in employment, retail sales and commercial GDP as provided by the Conference Board of Canada, June 2018 Economic Forecast. All of these values are at the BC Hydro wide service area while regional forecasts of these variables are used in developing sales forecasts which comes from the commercial SAE models.

3.3.3.2 Light Industrial Sector Load Forecast

Over the test period, the light industrial sector forecast shows an increase of 288 GWh. The majority of this increase is from cannabis and cryptocurrency loads. These loads represent customer requested loads that are considered highly probable based on their advanced stage of progress in BC Hydro's interconnection process. The remainder of the growth can be largely attributed to the natural gas sector loads, and construction loads in sales to other light industrial customers.

Demand growth from other light industrial customers is driven by projected provincial GDP which shows lower growth over the test period relative to past load forecasts. Table 3-7 shows the September 2018 forecast of provincial GDP growth from the B.C. Ministry of Finance.

Table 3-7 Real GDP Growth – British Columbia

Calendar Year	2015 (Actual)	2016 (Actual)	2017 (Actual)	2018 (Forecast)	2019 (Forecast)	2020 (Forecast)
Real GDP Growth (%)	3.5	3.5	3.6	2.2	1.8	2.0

Source: B.C. Ministry of Finance First Quarter Report Issued September 7, 2018.

3.3.4 Large Industrial Sector Load Forecast

The forecast for the Large Industrial sector and its respective sub-sectors is shown in Table 3-8.[92]

Table 3-8 Large Industrial Sales by Sub-Sector after Rates after DSM Savings

Fiscal Year	Mining (GWh)	Forestry (GWh)	Oil and Gas (GWh)	Other Large Industrial (GWh)	Total Sales (GWh)
F2013 (Actual)	3,102	8,351	961	1,117	13,530
F2014 (Actual)	3,529	8,234	1,032	1,177	13,972
F2015 (Actual)	3,808	7,959	1,116	1,173	14,055
F2016 (Actual)	3,883	7,390	1,276	1,149	13,698
F2017 (Actual)	3,884	6,723	1,373	1,126	13,106
F2018 (Actual)	3,880	6,954	1,507	1,171	13,513
F2019 (Forecast)	3,796	6,668	2,334	1,205	14,003
F2020 (Forecast)	3,884	6,541	2,740	1,537	14,702
F2021 (Forecast)	3,935	5,761	2,958	1,588	14,243

[92] Actual values in the table above are on billed sales basis because data for the large industrial sub-sector collected and forecasted on a billed basis. Forecast for fiscal 2019 includes six months accrued sales and six months forecast.

Over the test period, large industrial sector sales are expected to increase 730 GWh. As is shown in Table 3-8, this represents an increase of 699 GWh from fiscal 2019 to fiscal 2020 and then a decrease of 459 GWh from fiscal 2020 to fiscal 2021.

The forecast increase in electricity sales for the large industrial sector from fiscal 2019 to fiscal 2020 is primarily driven by growth in the oil and gas sub-sector and the other large industrial sub-sector. The forecast decrease from fiscal 2020 to fiscal 2021 is mainly from the decline in electricity sales to the pulp and paper segment which is consistent to the historical long-term trend in sales.

Descriptions of the forecasts for the large industrial sub-sectors are provided below:[93]

3.3.4.1 Mining

Over the test period, sales to the mining sub-sector are expected to increase by 139 GWh. This increase is primarily driven by expectations that our customers will undertake equipment upgrades in their existing operations. The forecast does not anticipate any new mines or the restart of operations at any mines.

For the years from fiscal 2019 to fiscal 2024, sales to mining are projected to revert to close to the level of fiscal 2018, as increases are offset by customers reaching end of mine life.

The following provides additional information on the metal and coal mining market outlook over the forecast period to fiscal 2024.

Metal Mines

Global copper demand is expected to continue to grow at a moderate rate driven by construction activity in China and global electrification of transportation and manufacturing. Trade conflicts are expected to have an effect in the short-term, but

[93] Additional descriptions of large industrial sub sectors and forecasts beyond fiscal 2021 can also be found in Appendix O, section 7.8.

are not expected to drive the global economy into a recession. For gold, the anticipated geopolitical environment and corresponding US dollar fluctuations suggest gold prices are expected to remain stable in the next few years.

Over the forecast period, at these price levels for copper and gold, existing customers are expected to operate normally, but have little incentive to bring new mines into production.

On January 7, 2019 Imperial Metals announced the suspension of operations at the Mt. Polley mine due to market conditions, and that operation will resume "once the economics of mining at Mt. Polley improve." As a result, BC Hydro expects reduced sales from Mt. Polley relative to the above mid forecast starting in fiscal 2020.

Coal Mining

The price for metallurgical coal has increased sharply over the last two years following a downturn from 2013 through 2016. Looking forward to fiscal 2024, the restarting of shuttered global operations is expected to reduce current coal prices. At these prices, we expect existing coal operations to continue normal operations, and that no new mines will start operations over the next six years.

The metallurgical coal load forecast expects some of our current customers to initiate equipment and production upgrades. This will be offset by the recent shutdown of the Coal Mountain operation by Teck resulting in a small increase over the test period.

3.3.4.2 Forestry

Over the test period, sales to the forestry sub-sector are expected to decline by 907 GWh. The decline is due mainly to the pulp and paper segment. The pulp and paper industry is expected to experience volatile but generally favourable commodity prices. Nevertheless, plant closure risk still exists because of underlying market and mill expectations facing publication paper mills.

The following provides additional information on the pulp and paper, wood product, and chemical segments market outlook and anticipated impact to sales. The forecast results of the segments are found in Table 7-24 of Appendix O, section 7.8.

Pulp and Paper

Over the test period, sales to the pulp and paper segment are expected to decline by about 782 GWh. Nearly the entire decline is due to publication paper mills, which are facing a number of challenges. Examples include aging equipment, fibre supply issues, and declining markets for their product. The decline in the test period reflects a continuation of declining sales to this segment in recent years. The factors that contributed to the decline were mill and mill line closures; more specifically, they include:

- Aging capital equipment;
- Declining fibre availability due to impacts from mountain pine beetle infestation and wildfires;
- Strong competition from new kraft mills in South America;
- Displacement of newspaper by digital media; and
- Increased use of electronic media by advertisers.

Over the Load Forecast period from fiscal 2019 to fiscal 2024, sales to the pulp and paper segment are projected to decline by about 30 per cent for the reasons stated above.

For pulp producers, favourable prices and fibre availability are expected over the forecast period from fiscal 2019 to fiscal 2024; which is the primary reason for a relatively flat sales forecast for these customers.

Wood Products

Over the test period, sales to the wood products segment are forecast to remain relatively stable with a small decline by 7 GWh. While sales have declined in recent years, sales increased between fiscal 2017 and fiscal 2018 due to record lumber prices which is reflected in the relatively stable sales over test period.

Over the forecast period from fiscal 2019 to fiscal 2024, we expect U.S. housing starts will continue to rise, however, the wood products segment faces ongoing uncertainties related to the U.S.-Canada softwood lumber dispute and BC fibre shortage (caused by the mountain pine beetle losses compounded by recent record wildfires). These issues will likely increase mill production costs and put downward pressure on sales.

Chemical

Over the test period, sales to the chemical segment (industries providing bleaching and cleaning agents) are expected to remain stable.

3.3.4.3 Oil and Gas

Over the test period, sales to the oil and gas sub-sector are expected to increase by 624 GWh. This increase is primarily driven by the growth in the shale gas segment from projects that recently started commercial operations or are currently under construction, and by the growth in propane terminals. This growth during the test period reflects a continued expected increase in sales of 827 GWh from fiscal 2018 to fiscal 2019. BC Hydro is not expecting electricity sales to LNG customers over the test period beyond sales to the FortisBC Tilbury plant, which is in operation.

Over the forecast period from fiscal 2019 to fiscal 2024, the load forecast for the oil and gas sub-sector expects sales to increase by approximately 2,465 GWh. Most of this growth is expected to continue to come from shale gas production as B.C.'s Montney shale basin remains a low cost producer of natural gas and natural gas liquids supplying North American and, increasingly, global markets. The remaining sales forecast is largely made up of demand growth in propane terminals and other oil and gas customers described below.

The following provides additional information on the major oil and gas segment sales market outlook and anticipated impact to sales. The forecast results of the segments are found in Appendix O, section 7.8, Table 7-24.

Shale Gas

Over the test period, the increase in sales to the shale gas segment is expected to be approximately 517 GWh. The shale gas segment represents about 50 per cent of the oil and gas sub-sector's sales. Customers in this segment are plants that recover and process natural gas and natural gas liquids. These customers operate in the Montney shale basin, which is located in northeast B.C. (around the Dawson Creek area). Historically, sales to these customers increased by about 500 per cent from fiscal 2013 through fiscal 2018.

Over the forecast period from fiscal 2019 to fiscal 2024, sales to the shale gas segment is expected to increase by approximately 1,333 GWh of which most of this is not related to LNG terminal development.

Other Large Oil and Gas Operations

Over the test period, sales to the other large oil and gas operations are expected to increase by about 122 GWh. Currently, sales to this segment represent about 50 per cent of the oil and gas sub-sector's sales. Customers in this segment include the conventional natural gas processing plants, pipelines (oil, condensates, natural gas), propane terminals and LNG terminals.

Over the forecast period from fiscal 2019 to fiscal 2024, sales to the other large oil and gas operations segment is expected to increase by approximately 1,133 GWh.

This growth is attributed to sales to LNG terminals, propane terminals, pipelines and conventional natural gas processing customers.

Publically available information on LNG projects which informed our load forecast included:

- LNG Canada Inc. recently made a positive final investment decision. Only construction-related load from this LNG facility is expected within the window of our load forecast;
- Woodfibre LNG announced that it intends to make a final investment decision this winter. We included a probability weighted sales forecast from this facility in its load forecast; and
- FortisBC Tilbury is in operation and we included forecast sales to this LNG facility.

3.3.4.4 Other Large Industrial

Over the test period, sales to the other large industrial customers are expected to increase by 383 GWh. The primary driver of this increase is forecast sales to new cannabis and cryptocurrency customers connected at the transmission voltage service level.

In addition to cannabis and cryptocurrency, a small amount of growth over the test period (approximately 80 GWh) is led by upgrades and expansions made by our existing customers.

Over the load forecast period from fiscal 2019 to fiscal 2024, sales to this sub-sector are expected to increase by 398 GWh. This growth is led by incremental cannabis and cryptocurrency loads which are well advanced in our inter-connection process.

3.3.5 Other Sector Load Forecast

Sales that make up the Other sector load includes electricity sales to FortisBC Electric, City of New Westminster, Hyder Alaska, street lighting customers and irrigation customers. Over the test period, the projected increase in sales to the other sectors loads is 75 GWh, where most of this increase is attributed to the forecast of electricity sales to FortisBC Electric from BC Hydro.

3.3.6 Many, but Not All, Uncertainties and Risks Are Reflected in the High and Low Bands

BC Hydro's recent forecast performance has been good, with the May 2016 forecast tracking within 0.1 per cent to 0.5 per cent of actuals per year for the first two years of the last test period. However, as summarized in section 3.2.10, there is uncertainty in developing load forecasts. Load forecasts are sensitive to many input variables that drive the forecast, which have varying degrees of uncertainty associated with them. These uncertainties influence the risk that future loads will be lower or higher than forecast. They can exist at a customer-specific level, sector-wide level or economy-wide level. Many uncertainties and risks are accounted for in the high and low bands, although some other uncertainties and risks remain unaccounted for.

3.3.6.1 Uncertainty and Risks Reflected in the High and Low Bands

Specific risks and uncertainties reflected in the high and low bands include:

- Economic risk continues to be a key uncertainty driver, particularly as it relates to future economic and housing growth forecasts. While the United States – Mexico - Canada trade agreement has been reached, there remains considerable downside uncertainty in world trade;
- Customer and project-specific uncertainties in the large industrial sector remain, particularly with the mining and forestry sub-sectors;
- While there is a high probability of growth in the upstream natural gas sector, the potential for even more exists;
- There is the possibility of a large and rapid increase in electrification;

- Little consensus exists about the future of emerging sectors of cryptocurrency and cannabis within British Columbia; and
- Predicting the trajectory of electric vehicle sales remains challenging.

To quantify the various uncertainties in the factors that increase or decrease load, BC Hydro develops a high and a low uncertainty bands around our mid load forecast.

The summary results from the Monte Carlo analysis, after load reductions for the mid DSM savings, are included in Table 3-3 above. The results show a symmetric distribution around the Mid Load Forecast where the band width increases further into the forecast period due to greater uncertainty.

Mathematically, the results of Monte Carlo analysis tend to produce a symmetrical distribution around the Mid Load Forecast. Despite this statistical result, there are a number of sectors for which the risk profile is asymmetrical wherein the potential for higher load relative to the Mid Load Forecast is greater than the potential for lower load. In particular, this asymmetry applies to growth industries such as the natural gas production. The asymmetry also applies to new loads such as LNG, electric vehicles, cannabis and cryptocurrency where there is minimal existing load and significant, albeit, uncertain growth potential. In contrast, for mature industries such pulp and paper, the potential for lower load relative to the Mid Load Forecast is greater than the potential for higher load. These asymmetrical risk profiles are captured in discrete low and high sub-sector load forecasts which are incorporated in the Monte Carlo analysis.

3.3.6.2 Uncertainty and Risks Not Fully Reflected in the High and Low Bands

For the test period, there are also risks that load will be higher or lower than forecast, where some of these are not fully captured within the uncertainty bands. Some of these risks include the following.

Potential upside risks to the Load Forecast:

- The CleanBC Plan, released by government in December 2018, is not reflected in the Load Forecast which was finalized in October 2018 but will be incorporated in future load forecast updates. By 2030, the CleanBC Plan could require approximately an incremental 4,000 GWh of energy over and above currently projected demand growth to electrify key segments of the economy. Some of the implications of this include a further commitment to electric vehicle incentives which may mean more electric vehicle sales and associated loads, increased building load and increased natural gas sector load.
- There are several idled mines and pulp mills that could re-start. While we develop a high load forecast for each of the large industrial sub-sectors by undertaking plant-specific assessments, we cannot anticipate all potential high load scenarios.
- Estimates of the overlap in codes and standards are based on our internal work on the extent of the overlap over the various diverse set of electrical appliances and uses of electricity. Further work in this area may lead to revised overlap projections.
- The forecast assumes historical average temperature trends. If temperatures are colder than normal this can led to higher sales.

Potential downside risks to the Load Forecast:

- The Load Forecast over the entire short-term period does not reflect any specific period of an economic recession or recovery. The timing and duration of these events cannot be forecasted with certainty; although recessions may lead to reduced loads as was the case with the 2008/2009 recession. The Conference Board of Canada, which provided the economic forecasts used to develop BC Hydro’s Load Forecast, does not attempt to forecast recessions. Even so, BC Hydro monitors economic reports and near term trends. Since our

Load Forecast was completed there has been an increase in reported concerns regarding the state of the economy. For example, the Business Council of B.C.'s January, 2019 news release points to a number of external and domestic risk factors that may adversely impact economic activity. Nevertheless, the Business Council of B.C. is still projecting the BC economy to expand in fiscal 2020 (2.2 per cent real GDP), which is consistent with the Conference Board of Canada's and B.C. Ministry of Finance forecast.[94,95]

- Specific customer sites could curtail operations or shut down. While we develop a Low Load Forecast for the large industrial sector by undertaking plant-specific assessments, we cannot anticipate all potential low load scenarios.
- Housing starts and growth in housing stock may vary from Conference Board of Canada forecasts as a result of various factors impacting the housing market such as new taxes and higher interest rates. This could result in lower sales to the residential sector over the test period.
- Warmer than anticipated temperatures. For example, sales to the residential sector declined by close to 5 per cent between fiscal 2014 and fiscal 2015 mainly due to warmer temperatures.

3.4 Revenue Forecast Methodology is Unchanged

The Revenue Forecast is used to determine the revenue shortfall and the proposed rate increases to meet BC Hydro's forecast revenue requirements. The forecast methodology uses load and customer projections from the Load Forecast in section 3.3 above and applies approved fiscal 2019 tariff rates to calculate revenue. The Revenue Forecast is a straightforward calculation, relative to the preparation of the Load Forecast, and the method is unchanged from the last Application.

[94] British Columbia Business Council News Releases and Op-Eds. Finlayson Column: Four questions on the B.C. economy in 2019. January 21, 2019.

[95] As noted in section 3.2.7.3, BC Hydro's supplants the Conference Board's GDP forecast with the B.C. Ministry of Finance GDP forecasts for the first five years of the forecast period.

3.4.1 Revenue Forecast Focusses on Domestic Revenues

Domestic revenues are comprised of revenues from the sale of electricity to BC Hydro's customers within the province and to certain customers outside of the province under treaty or long-term contract with BC Hydro (specifically, the Skagit Valley Treaty commitment and sales to Tongass Power and Light in Hyder, Alaska). Domestic revenues do not include any Open Access Transmission Tariff revenues, which are addressed in Chapter 9. The Domestic Energy Sales and Revenue Forecast is provided in Appendix A, Schedule 14. Note that miscellaneous revenues are not included in Domestic Revenues. Refer to Chapter 8, section 8.7, for details of miscellaneous revenues.

The method used to forecast revenue from each customer sector is discussed below.

3.4.2 Residential Sector Revenue Forecast Methodology is Unchanged

The Residential Sector Revenue Forecast methodology is unchanged from the Previous Application. The Residential Sector Revenue Forecast is the sum of revenue from basic charges and energy charges. Basic charge revenue is the product of forecast number of accounts and residential basic charge. Energy charge revenue is the product of forecast consumption for the residential class and residential energy charges.

3.4.3 Light Industrial/Commercial Sector Revenue Forecast Methodology is Unchanged

The Light Industrial/Commercial Sector Revenue Forecast methodology is also unchanged from the Previous Application.

The Light Industrial/Commercial Sector Revenue Forecast includes the Small General Service, Medium General Service, and Large General Service customer classes, and the Revenue Forecast is the sum of revenue from these three general service customer classes.

The Small General Service Revenue Forecast is the sum revenue from basic charges and energy charges. Basic charge revenue is the product of forecast number of accounts and Small General Service basic charge. Energy charge revenue is the product of forecast consumption and Small General Service energy charge.

The Medium General Service and Large General Service Revenue Forecasts are the sum of revenue from basic charges, demand charges and energy charges. Basic charge revenue is the product of the forecast number of accounts and Medium General Service and Large General Service basic charge. Demand charge revenue is the product of projected demand and Medium General Service and Large General Service demand charge. Energy charge revenue is the product of forecast consumption and Medium General Service and Large General Service energy charge.

3.4.4 Large Industrial Sector Revenue Forecast Methodology is Unchanged

The Large Industrial Revenue Forecast methodology is also unchanged from the Previous Application and now includes the forecast revenue from LNG customers. In October 2018, as described in Chapter 2, section 2.5.9, the Government of B.C. removed a previous provision that prevented LNG customers from receiving service under BC Hydro’s transmission rate schedules. This means that revenue from LNG customers is now recorded as generate rate revenue and not as a separate line item.

The Large Industrial Revenue Forecast is the sum of the Revenue Forecast for each transmission customer, comprised mostly of transmission service stepped rate customers and transmission service exempt rate customers The Revenue Forecast for each customer is the sum of energy charge revenue and demand charge revenue. The energy charge revenue for transmission service stepped rate customers is calculated by comparing the forecast consumption for each customer to the customer's fiscal 2018 interim Customer Baseline Load. Forecast consumption for each customer up to and including 90 per cent of the customer's Customer Baseline Load is priced at the Tier 1 energy charge, and the balance of forecast consumption above the customer's Customer Baseline Load is priced at the Tier 2 energy charge. The energy charge revenue for transmission service exempt rate customers is the product of forecast consumption and transmission service exempt rate energy charge. The demand charge revenue is the product of projected demand and large industrial demand charge.

3.4.5 Other Sector Revenue Forecast Methodology is Unchanged

The Other Sector Revenue Forecast methodology is also unchanged from the Previous Application.

The Other Sector Revenue Forecast for the other sector is the sum of revenue for irrigation, street lighting customers, and sales to other utilities including the City of New Westminster, FortisBC Electric, City of Seattle, and Tongass Power and Light (in Hyder, Alaska).

The Revenue Forecasts for irrigation and street lighting customers are the products of forecast sales to irrigation and street lighting customers and the average revenue rates applicable for the respective customer classes.

The Revenue Forecast for City of New Westminster is the sum of energy charge revenue and demand charge revenue. Energy charge revenue is the product of forecast sales to the City of New Westminster and the transmission service exempt rate energy charge. Demand charge revenue is the product of projected demand and the transmission service rate demand charge.

The Revenue Forecast for FortisBC Electric is the sum of energy charge revenue and demand charge revenue. Energy charge revenue is product of forecast sales to FortisBC Electric and the transmission service FortisBC Electric energy charge.

Demand charge revenue is the product of the projected demand and the transmission service FortisBC Electric demand charge.

The Revenue Forecast for the City of Seattle is the product of forecast sales to the City of Seattle and the price per MWh committed in the Skagit River Valley Treaty. The adoption of IFRS 15, *Revenue from Contracts with Customers*, effective for fiscal 2019, resulted in an increase in the price per MWh for fiscal 2019 onwards as described in Chapter 8, section 8.13.

The Revenue Forecast for Tongass Power and Light is the product of forecast sales to Tongass Power and Light and the average revenue rate for the customer class.

3.5 Test Period Revenue Forecast

Table 3-9 below summarizes the domestic Revenue Forecast as shown on Appendix A, Schedule 14.0.

Table 3-9 Fiscal 2017 to Fiscal 2021 Domestic Revenues

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Residential	14.0 L11	1,914.8	1,916.2	1,991.4	1,996.8	2,067.9	2,037.8	2,072.8	2,082.0
2	Light Industrial and Commercial	14.0 L12	1,703.2	1,714.7	1,758.4	1,770.6	1,821.9	1,832.5	1,835.9	1,840.8
3	Large Industrial	14.0 L13+L19	748.5	732.9	774.6	772.5	840.9	841.0	895.3	874.6
4	Other	14.0 L14:L18	120.3	122.2	124.4	122.4	129.1	141.0	144.2	144.9
5	Subtotal	14.0 L20	4,486.8	4,486.0	4,648.9	4,662.3	4,859.8	4,852.3	4,948.2	4,942.4
6	Revenue from Deferral Rider	14.0 L21	223.5	223.7	231.3	233.2	268.1	241.6	0.0	0.0
7	Total	14.0 L22	4,710.3	4,709.7	4,880.2	4,895.5	5,127.9	5,093.9	4,948.2	4,942.4

The Revenue Forecast for fiscal 2020 to fiscal 2021 is based on fiscal 2019 rates approved by the Decision from the Previous Application, and excludes the proposed rate increases sought in this application and the impact of any future rate structure changes.

In fiscal 2020, total revenue is forecast to decrease by $145.7 million or 2.9 per cent over the fiscal 2019 Forecast, largely due to the elimination of the deferral rider, as discussed in Chapter 1. Before revenue from the deferral account rate rider, revenue is higher by $95.9 million or 2.0 per cent, consistent with energy sales which are forecast to increase by 1.8 per cent, as discussed in section 3.3.

In fiscal 2021, total revenue is forecast to decrease by $5.8 million or 0.1 per cent, consistent with energy sales which are forecast to decrease by 0.6 per cent over the fiscal 2020 Plan, as discussed in section 3.3.

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Revenue Requirements Application

Chapter 4

Cost of Energy

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4.1 Introduction

This chapter discusses BC Hydro's energy costs. BC Hydro is not, as part of this application, proposing any generation projects or seeking acceptance of any Electricity Purchase Agreements (**EPAs**). Rather, this chapter provides the necessary information to demonstrate that the forecast Cost of Energy is reasonable for the purpose of setting rates in the test period. The forecast Cost of Energy is used in determining our total revenue requirements for the purpose of this application, however, customers ultimately only pay the actual Cost of Energy through the use of regulatory accounts.

This Chapter is organized around the following key points:

- Section 4.2 provides background information on how BC Hydro's Cost of Energy is categorized. In light of the elimination of the Heritage Contract, BC Hydro has restructured the presentation of the Cost of Energy in our revenue requirements model to improve clarity of the accounting treatment of our Cost of Energy.[96] The presentation change has no operational or financial impact.
- Section 4.3 describes BC Hydro's approach to managing future energy supply, which includes a number of steps to reduce IPP energy costs. This section also discusses the impacts of the Comprehensive Review on BC Hydro's Cost of Energy.
- Section 4.4 discusses how BC Hydro maximizes the expected value of its energy supply portfolio through its use of monthly Energy Studies. The

96 The costs of Market Electricity Purchases, Surplus Sales, Net Purchases (Sales) from Powerex and Domestic Transmission - Export were previously distributed into Heritage and Non Heritage Energy costs, based on the Heritage Contract threshold of 49,000 GWh. As discussed in Chapter 2 section 2.2.1, as part of the Comprehensive Review, the Government of B.C. repealed Direction No. 7 to the BCUC, which included the Heritage Contract. The repeal of the Heritage Contract has no impact on BC Hydro or ratepayers; however, it provides BC Hydro with the flexibility to re-categorize its Cost of Energy for this application by creating a third category, Market Energy, which includes the four components – Market Electricity Purchases, Surplus Sales, Net Purchases (Sales) from Powerex and Domestic Transmission - Export.

methodology has been endorsed by independent experts as part of a recent audit.

- Section 4.5 provides BC Hydro's forecast Cost of Energy for the test period, and explains the treatment of variances between the forecast Cost of Energy and actual Cost of Energy. While the forecast Cost of Energy is used in determining our revenue requirements, the BCUC approved regulatory accounts ensure that customers ultimately only pay for the actual energy costs.
- Sections 4.6, 4.7 and 4.8 provide a more detailed breakdown of the Cost of Energy by category (Heritage, Non-Heritage and Market). The amounts shown in these sections are presented in the Gross View (i.e., total costs before any forecast transfers to, or recoveries from, regulatory accounts). Overall, by fiscal 2021, BC Hydro's Cost of Energy is forecast to increase by $157 million from the fiscal 2019 RRA amount. This forecast increase is primarily driven by an increase in costs related to IPPs and Long-Term Commitments. These forecast costs are primarily associated with existing EPAs, and because the terms of these agreements are already set, the forecast costs for these EPAs are largely prescribed. With few exceptions, BC Hydro is not acquiring new resources from IPPs and those exceptions represent only a very small portion of the forecast Cost of Energy.

4.2 BC Hydro Has Clarified the Presentation of Cost of Energy

This section provides background information on how BC Hydro's Cost of Energy is categorized. In its Decision on the Previous Application the BCUC directed BC Hydro to explain, in a Compliance Filing, the accounting treatment of surplus energy costs and recoveries.[97] As a result of some of these questions, in this application, BC Hydro has restructured the presentation of Cost of Energy in the

97 BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 RRA (March 1, 2018), page 112.

revenue requirements model for clarity purposes. The financial treatment of energy costs, and the way the system is operated remain unaffected by the change in presentation.

4.2.1 The Repeal of the Heritage Contract has Facilitated an Improved Presentation

BC Hydro's Cost of Energy was previously categorized into Heritage Energy and Non-Heritage Energy. This practice stems from the Heritage Contract, which was recently repealed as a result of the Government of B.C.'s Comprehensive Review. The Comprehensive Review is discussed further in Chapter 1, section 1.4 and the report on the Comprehensive Review is provided as Appendix C.

The repeal of the Heritage Contract has no impact on BC Hydro's planning or operations as BC Hydro manages all sources of energy supply as a single portfolio. However, without the Heritage Contract, BC Hydro now has the flexibility to categorize its Cost of Energy differently in its revenue requirements model for this application. In Schedule 4.0 of Appendix A to this application, which sets out BC Hydro's Cost of Energy, BC Hydro has re-categorized its Cost of Energy into:

- Heritage Energy;
- Non-Heritage Energy; and
- Market Energy.

These categories are for presentation purposes only and are intended to provide better clarity on the presentation of our Cost of Energy. We believe that these categories will make it easier to understand BC Hydro's energy costs. Further details on the costs in each category are provided in the sections below.

4.2.2 Heritage Energy Costs: Related to Heritage Assets

Heritage Energy costs are the energy costs related to the operation of heritage assets listed in the *Clean Energy Act*[98]. Heritage Energy costs include the following:

- **Water Rentals:** This includes water rental fees paid on the generation output and capacity of the heritage assets, including BC Hydro's one-third interest in the Waneta generation facility.[99] It also includes water rental fees paid on storage as well as miscellaneous water licences for the use of water for purposes other than power generation, including domestic use and irrigation.
- **Natural Gas for Thermal Generation:** This includes the natural gas purchases, gas transportation, carbon tax, motor fuel tax and other related costs associated with BC Hydro's Prince Rupert and Fort Nelson generation facilities.
- **Domestic Transmission – Other:** This includes transmission costs associated with BC Hydro's obligations under the Skagit River Valley Treaty.[100]
- **Columbia River Treaty Related Agreements:** This includes costs or recoveries associated with the Non-Treaty Storage Agreement[101] and a short-term coordination agreement related to the Libby Coordination Agreement.[102]

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98 Heritage assets are set out in Schedule 1 of the *Clean Energy Act*. Under the *Clean Energy Act*, BC Hydro must not sell or otherwise dispose of the heritage assets unless a heritage asset is no longer used or useful for its intended purpose or is to be replaced with one or more assets that will perform similar functions, and with the approval of the BCUC.

99 Consistent with BCUC Order No. G-130-18, water rental fees paid on the generation output and capacity of BC Hydro's two-thirds interest in the Waneta Generation Facility, purchased in 2017 and now leased to Teck, are considered Non-Heritage Energy. Please refer to section 4.7.

100 As explained in Chapter 2, section 2.5.6, the Government of B.C. and the City of Seattle signed an agreement in 1984 concerning the supply of electricity to the City of Seattle (the Skagit River Valley Treaty). The Government of B.C. subsequently assigned certain rights and obligations under this agreement to BC Hydro. BC Hydro's domestic customers receive the benefit of revenues from sales to Seattle City Light, offset by the costs of serving this obligation. These revenues are included as Other Sector revenue as shown in Appendix A, Schedule 14, line 18.

101 The Non-Treaty Storage Agreement is a coordination agreement between BC Hydro and the Bonneville Power Administration to operate non-treaty storage at Kinbasket Reservoir (Arrow Lakes).

102 A short-term coordination agreement, related to the Libby Coordination Agreement, between BC Hydro and Bonneville Power Administration and the U.S. Army Corps of Engineers.

- **Remissions and Other:** The *Water Sustainability Act* specifies remissions that are available to be applied against water rental payments. These remissions are compensation for new restrictions or regulations imposed on the licensee arising from water use plans. Remissions are capped at $50 million per calendar year, with any excess associated with physical works requirements carried forward into future years.
- **Exchange Net:** This is primarily the transfers of energy that are related to BC Hydro's entitlement obligations under the Canal Plant Agreement and the Keenleyside Entitlement Agreement. [103] These energy transfers are not financial transactions, but may result in reimbursement or payment of water rental fees. The financial impact of such reimbursements and payments are recorded with Water Rentals. For reporting of actuals, Exchange Net also includes energy that is used to reconcile the total sources of supply to the total recorded load, for financial statement purposes.

4.2.3 Non-Heritage Energy Costs: Related to Energy Other than Heritage Energy or Market Energy

Non-Heritage Energy costs are the energy costs not categorized as Heritage Energy costs or Market Energy costs, and include the following:

- **IPPs and Long-Term Commitments:** This includes BC Hydro's EPAs with IPPs connected to BC Hydro's integrated system, including gas transportation and commodity costs associated with the Island Generation facility.
- **Non-Integrated Area:** Communities in the Non-Integrated Area are not connected to BC Hydro's integrated system and are served by local generating

[103] The Canal Plant Agreement is a "one-operator" coordination agreement where BC Hydro dispatches generating plants on the Kootenay and Pend-d'Oreille rivers that are owned by parties to the agreement (Fortis BC, Teck, Brilliant Power Corp, Brilliant Expansion Power Corp and Waneta Expansion Ltd. Partnership) and BC Hydro in order to obtain optimum generation. The plant owners make the actual generation available to BC Hydro in exchange for a fixed monthly energy and capacity entitlement. Similarly, the Keenleyside Entitlement Agreement provides the project owner (Arrow Lakes Power Corporation) – with an energy and capacity entitlement associated with the Arrow Lakes Hydro project on the Columbia River.

facilities and distribution networks. Generating capacity in these areas is provided by a combination of BC Hydro owned diesel generating stations, as well as hydro and biomass IPP facilities (and one BC Hydro owned hydro facility[104] in the Bella Coola region).

- **Gas and Other Transportation:** This includes costs related to upstream gas transportation contracts entered into by BC Hydro and external electricity transmission charges incurred to serve domestic load in the Fort Nelson, Goodlow (Boundary Lake), Rogers Pass, and Duck Lake areas.
- **Water Rentals (Waneta Two-Thirds):** In 2017, BC Hydro entered into a purchase agreement with Teck for the remaining two-thirds interest of the Waneta generation facility. The BCUC approved this purchase by Order No. G-130-18. The 2017 Waneta transaction includes a long-term lease agreement with Teck. Under the arrangements with Teck, BC Hydro continues to use its one-third interest in Waneta to serve its domestic load obligations. The remaining two-third interest is leased back to Teck and Teck is responsible for the water rental payments in relation to its leased interest. These costs are shown as an offset in Miscellaneous Revenues (Appendix A, Schedule 15.0, line 22).

4.2.4 Market Energy Costs and Revenues: Related to Electricity Purchased or Sold Outside of B.C.

Market Energy is electricity purchased from or sold to Powerex through transfer pricing arrangements between Powerex and BC Hydro. The costs or revenues associated with these transactions are allocated to the following categories:

- **Market Electricity Purchases:** This is often referred to as domestic purchases and represents market purchases of electricity from Powerex by BC Hydro to

[104] Actual water rental costs for the Clayton Falls Generating Station, which are approximately $67,000 per year, are included with Water Rentals for ease of reporting.

meet domestic load requirements. This does not include purchases included in Net Purchases (Sales) from Powerex.

- **Surplus Sales:** This is often referred to as domestic sales and represents sales of electricity to Powerex, when BC Hydro has generation in excess of its domestic load requirements. This does not include sales included in Net Purchases (Sales) from Powerex.
- **Net Purchases (Sales) from Powerex:** This is often referred to as trade purchases (sales) and represents Powerex purchases/sales from/to BC Hydro for the purpose of trade related activities, provided that the BC Hydro system has the ability to accommodate those transactions. These are not purchases (sales) for domestic purposes.
- **Domestic Transmission – Export:** This represents transmission costs within B.C. related to Surplus Sales.

4.3 Managing Our Future Energy Supply

BC Hydro's approach to managing its future energy supply incorporates the following two components which are discussed in the sections below:

1. We have an investment strategy in place to support appropriate capital planning for the heritage assets.
2. We are managing our energy costs from IPPs by, among other things, reducing the volume of IPP energy where there are cost savings to BC Hydro and pursuing the renewal of some existing IPP contracts to meet future long-term energy needs.

As explained in section 4.3.3 below, the opportunities to manage supply costs are more limited in the Non-Integrated Areas.

4.3.1 BC Hydro is Optimizing the Heritage Assets

In its Decision on the Previous Application, the BCUC expressed concern that the heritage assets may not be providing optimal value to BC Hydro customers, and that actual energy delivered by BC Hydro's heritage assets for distribution has been reduced below availability due to energy supplied by IPP energy.[105]

BC Hydro is optimizing the use of heritage assets through our approach to both operations and capital investment.

- Our monthly Energy Studies optimize our operational management of all sources of energy supply on BC Hydro's integrated system. Further information is provided in section 4.4 below.
- Our capital planning process seeks to optimize our investment strategy for generation resources by categorizing our heritage assets as "Key", "Strategic" or "Available", according to the significance of the facility to BC Hydro's system. BC Hydro's Generation Strategic Asset Management Plan sets out a 10-year strategy for each category. Further information is provided in Chapter 6, section 6.4.2.1.

4.3.2 BC Hydro is Proactively Managing IPP Energy Costs

BC Hydro's forecast increases to our Cost of Energy are primarily driven by increasing IPP energy costs under existing agreements. BC Hydro is not acquiring new resources from IPPs, with the exception of a small number of new First Nations energy projects and some EPA renewals,[106] such as new contracts under the Biomass Energy Program. The forecast increase in IPP energy costs from fiscal 2019 to fiscal 2021 is in large part due to pre-determined factors, including price escalation terms and other terms in existing EPAs, and new IPP projects from

105 BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 25.

106 EPA renewals are new contracts that replace existing EPAs, and are not extensions of existing agreements.

existing EPAs reaching commercial operation. Further information is provided in section 4.7.1 below.

BC Hydro and the Government of B.C. have taken the following steps related to IPP power acquisitions:

- **No active energy procurement programs:** BC Hydro does not have any active programs for the procurement of new energy resources from IPPs. Other than EPA renewals, the only expected new EPAs are a small number of new First Nations energy projects.
- **SOP is indefinitely suspended:** The SOP (which also includes the Micro-Standing Offer Program) is an indefinitely suspended program that was for small, permit ready, clean energy projects. In February 2017, BC Hydro initiated a review of the SOP and stopped assigning annual target volumes for 2020 and beyond. Subsequently, BC Hydro announced that the SOP was suspended while the Government of B.C.'s Comprehensive Review was underway. In February 2019, as part of the Comprehensive Review, the Government of B.C. issued a regulation which allowed BC Hydro to indefinitely suspend the SOP.[107] BC Hydro will not be executing any other SOP EPAs, with the exception of five[108] First Nations' clean energy projects that are part of Impact Benefit Agreements with BC Hydro and/or are mature projects that have significant First Nations involvement.
- **Terminations and other volume reductions:** In its Decision on the Previous Application, the BCUC observed that there is a potential for cost savings if additional IPP contracts are canceled or amended to reduce the volume of IPP

[107] Refer to Appendix C, page 27.
[108] As of October 1, 2018, BC Hydro had executed one of the five agreements.

purchases.[109] BC Hydro continually manages its rights and obligations under existing EPAs with IPPs, for example:

- As reported in the Previous Application, from fiscal 2014 to fiscal 2015, BC Hydro:
  - Terminated 14 EPAs;
  - Deferred 11 EPAs; and
  - Downsized and/or deferred two EPAs.
- As of the date of this application, since fiscal 2015, BC Hydro has:
  - Terminated an additional three EPAs[110]; and
  - Not renewed three other EPAs that expired.[111]

In addition, BC Hydro actively enforces its rights and obligations in EPAs to reduce cost commitments, such as exercising turn down rights when it is cost effective to do so.

- **Selective renewals at lower prices, subject to BCUC acceptance in section 71 applications:** In its Decision on the Previous Application, the BCUC also recommended that BC Hydro consider the timing of its existing IPP contracts and contract renewals.[112] Generally, BC Hydro pursues the renewal of expiring EPAs to meet future long-term energy needs where it is cost-effective. Through bilateral negotiations, BC Hydro has renewed contracts with IPPs at lower prices than under their original contracts. As discussed in Chapter 2, section 2.4.4, BC Hydro is not seeking approval of any EPA

[109] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 26.
[110] Conifex Mackenzie - Combined Heat and Power Project, Fries Creek, and Septimus Creek Wind Farm.
[111] As of October 1, 2018, the EPA for McDonald Ranch was expired and not renewed. Since this date, two additional EPAs (Seaton Creek Hydro and Morehead Creek Hydro) have expired and have not been renewed; however, these two EPAs were included in the forecast for the purpose of this application because the decision to not renew was made after the forecast was finalized.
[112] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 28.

renewals in this application and BC Hydro has filed separate applications, pursuant to section 71 of the *Utilities Commission Act*, seeking acceptance of each energy supply contract.

Since fiscal 2016, BC Hydro has renewed six run-of-river hydro EPAs and one storage hydro EPA. Four of the run-of-river hydro EPAs have been accepted by the BCUC as being in the public interest. The remaining two run-of-river hydro EPAs and the storage hydro EPA are the subject of an application that is currently being reviewed by the BCUC.[113]

BC Hydro also entered into short-term extension agreements for two biomass EPAs that were due to expire prior to April 2018, extending their respective terms up to September 2019. These short-term extension agreements were a bridging mechanism while BC Hydro, in consultation with the Government of B.C., was developing a longer term strategy for biomass facilities. As required under section 71 of the *Utilities Commission Act*, these extension agreements have been filed with the BCUC for acceptance. The BCUC suspended its proceedings on these agreements pending the completion of the first phase of the Comprehensive Review.

- **Biomass Energy Program:** As part of the Comprehensive Review, the Government of B.C. announced the Biomass Energy Program. As discussed in the Comprehensive Review, the Biomass Energy Program is a cost and volume limited, transitional measure to provide for the continued operation of biomass generating facilities with EPAs expiring over the next three years. The intent of the program is to allow time for the forest sector to develop and implement new product lines to diversify and become more competitive while also providing optionality should BC Hydro require additional supply resources in the future.

[113] Sechelt Creek IPP and Walden North IPP are run-of-river hydroelectric generating facilities, and Brown Lake IPP is a storage hydroelectric project.

Under the Biomass Energy Program, BC Hydro will potentially renew up to 80 per cent[114] of the historical aggregate energy deliveries from biomass IPPs whose EPAs are expiring in the next three years. BC Hydro will procure this energy through a combination of load offset[115] and/or energy purchases with a priority given first to load offset.[116]

The price paid for biomass energy under this program will be lower than current contracts to reflect changed market conditions for electricity. The Government of B.C. has indicated that it intends to provide a direction to the BCUC with respect to the approval of the program documentation and to require the costs associated with the program to be recovered from ratepayers.

4.3.3 Opportunities to Reduce Supply Cost Commitments in Non-Integrated Area are More Limited

BC Hydro serves 14 non-integrated areas.[117] Non-Integrated Area communities are not connected to BC Hydro's integrated system and are served by local generating facilities, primarily diesel, and distribution networks. In support of CleanBC, and BC Hydro's clean energy commitment, we actively look for opportunities to displace diesel generation with clean or renewable resources in Non-Integrated Area communities when it is cost-effective to do so.

There are two types of energy costs related to serving these communities: costs from BC Hydro diesel generating facilities and IPP costs.[118] Given the remoteness of

[114] The 2013 Integrated Resource Plan assumed that 50 per cent of the aggregate energy volume of expiring biomass contracts would be renewed. As a result of the Biomass Energy Program, as outlined in the Comprehensive Review, the aggregate renewal energy volume will be up to 80 per cent.

[115] A load offset is energy generated by a BC Hydro customer at its customer site to offset the energy purchased from BC Hydro to serve the load at this same site.

[116] The total estimated impact of the cost and energy volumes for the load offset and energy purchase contracts are included in the Application under Cost of Energy. However, BC Hydro is currently assessing the accounting treatment of the load offset component and the allocation of costs and energy volume may change to reflect the appropriate accounting treatment.

[117] Non-Integrated Areas: Zone IB is Bella Bella and Zone II is Anahim Lake, Atlin, Bella Coola, Dease Lake, Elhlateese, Fort Ware, Good Hope Lake, Haida Gwaii, Hartley Bay, Jade City, Telegraph Creek, District of Toad River and Tsay Keh Dene.

[118] There are no forecast energy costs for Clayton Falls Generating Station, as they are quite small. Actual costs are captured in Water Rentals, as noted in footnote 104.

these communities and the lack of connection to the integrated system, there are limited opportunities to reduce supply costs.

There are currently five non-integrated IPPs in operation.[119] BC Hydro has been pursuing the renewal of its EPA with the Ocean Falls IPP which serves the Non-Integrated Area of Bella Bella. BC Hydro and the IPP have not been able to reach agreement and have been operating under short-term extensions of the original EPA because BC Hydro has no other options to serve the region besides operating our diesel generation facility. In August 2017, BC Hydro filed an application for a service rate from the IPP with the BCUC. This application is currently before the BCUC.

4.4 Maximizing the Value of Our Energy Supply

This section explains the role of our monthly Energy Studies in optimizing our operational management of all sources of energy supply on BC Hydro's integrated system, including the heritage assets.

4.4.1 Energy Studies Inform Dispatch Decisions and Forecast Cost of Energy

The primary objectives of the Energy Study are to forecast:

- The marginal value of water in BC Hydro's two largest reservoirs (Williston and Kinbasket) that is used to inform operational dispatch decisions; and
- The Cost of Energy for financial reporting.

The forecast monthly marginal value of water provides BC Hydro with a relative measure that guides the operation of these reservoirs in the context of market and system conditions (i.e., when domestic energy resources should be dispatched versus purchases made from Powerex or when additional domestic resources

[119] Non-integrated Area IPPs: Hluey Lake (Dease Lake), Moresby Lake (Haida Gwaii), Ocean Falls (Bella Bella), Pine Creek (Atlin) and Kwadacha Bioenergy Project (Fort Ware) are operational facilities and Gabion River EPA (Hartley Bay) has not reached commercial operation.

should be dispatched to facilitate sales to Powerex). This output of the monthly Energy Study allows us to manage our integrated system to maximize the value for ratepayers.

The forecast Cost of Energy is used for financial reporting purposes. This forecast cost is based on outputs from the Energy Study, which develops an optimal set of reservoir and generation station operations and market transactions, given the current forecasts of water inflow, market prices, and weather adjusted load.

4.4.2 Independent Experts Endorsed BC Hydro's Energy Study Methodology

In fiscal 2019, BC Hydro undertook an internal audit of our monthly Energy Studies process. The internal audit relied on two subject matter experts from SINTEF[120], an independent energy research organization that conducts contract research and development projects. These experts are specialized in load forecasting, risk management, hydrothermal market modelling and hydropower scheduling models.

The internal audit concluded that BC Hydro has a well-established Energy Studies process in place, that key models are appropriate and that the methodologies applied are in line with leading industry practices. The Energy Studies Process Internal Audit Report is provided as Appendix DD.

4.4.2.1 Energy Study Inputs

The following list outlines the various inputs used by the Energy Study:

- **The Load Forecast:** The Load Forecast, net of demand-side management savings, including a potential range based on historic weather variability. The Load Forecast is set out in Chapter 3.
- **Forecast of IPP supply:** The forecast of supply from IPPs and Long-Term Commitments including a potential range based on historic supply and

[120] The Foundation for Scientific and Industrial Research at the Norwegian Institute of Technology

seasonal variability. IPPs and Long-Term Commitments are discussed in section 4.7.1.

- **The range of water inflow conditions:** Inflows to BC Hydro reservoirs are inputs to the Energy Study and are the largest drivers of energy production and reservoir operation. Inflows are driven by a combination of rainfall, snow pack and glacier meltwater. Once the snowpack has melted, usually towards the end of summer, rainfall becomes the primary driver of reservoir inflows.

  Seasonal inflow forecasts are made at the beginning of every month for each of 25 basins which contribute to BC Hydro's energy supply. Each inflow forecast incorporates the historical variability observed in meteorological conditions since 1973. The Energy Study accounts for this range of potential inflow scenarios in its forecast of generation and reservoir operations.

- **Electricity and gas market prices:** Surplus sales, market electricity purchases and the cost to run thermal generation all depend on forecasts of electricity and gas market prices. Electricity and gas prices tend to follow a seasonal cycle with higher prices during the colder winter months and hotter summer months, and lowest prices during the spring freshet.

  At the beginning of each Energy Study, Powerex provides BC Hydro with forward market price curves for electricity at Mid-C and gas prices at Sumas. The Energy Study uses these forward curves as a starting point and then adds variability to these prices to capture an expected range of price uncertainty.

  During fiscal 2020 and fiscal 2021, Sumas gas forward prices are expected to range from $1.50 to $3.07 USD/MMBtu with an average price of $2.10. Mid-C forward monthly electricity prices are expected to range from $7.85 USD/MWh in light load hours during the freshet to $49.95 USD/MWh in heavy load hours.

  System, market and weather conditions can significantly affect market prices. Large snowpack, windy and wet conditions act to depress the Mid-C electricity price, while hot, dry summer or cold winter conditions act to raise Mid-C prices.

For example, the October 2018 rupture of the Enbridge T-South pipeline and subsequent gas curtailment resulted in Sumas spot gas prices reaching $66 USD/MMBtu in November 2018.

- **Generation unit availability:** Energy production and plant capacity is affected when generation units are taken offline for maintenance, de-rated or forced out of service. The Energy Study accounts for unit and plant maintenance schedules as well as outages required for BC Hydro's capital plan. In addition, historic reliability data is used to account for the risk of forced outages.

4.4.3 BC Hydro's Objective is to Maximize Consolidated Net Revenue to Benefit Customers

As part of minimizing costs to ratepayers, BC Hydro's objective is to maximize "expected consolidated net revenue from operations". "Consolidated" refers to the combined activity of both BC Hydro (domestic) and forecast Powerex (trade). "Net revenue from operations"[121] includes both revenues and costs that are variable and forecast through the Energy Studies. By managing the system as a whole to maximize forecast consolidated net revenue, BC Hydro is able to optimize our portfolio of resources to achieve the best value for ratepayers.

The following list outlines the components of consolidated net revenue.

- **Domestic revenue from accrued sales:** These sales depend on consumption by BC Hydro's customers. They are not impacted by system dispatch decisions.
- **Cost of IPPs and Long-Term Commitments:** These costs arise from payments made to IPPs in accordance with their agreements. Other than Island Generation and certain biomass facilities, most IPPs are not directly impacted by system dispatch decisions.

[121] Net Revenues from Operations = domestic revenue from accrued sales plus revenue from surplus (domestic) sales plus revenue from Columbia River Treaty related agreements less cost of IPPs and long-term commitments less cost of market electricity (domestic) purchases less cost of water rentals less cost of natural gas for thermal generation less cost of net purchases (sales) from Powerex.

- **Revenue from surplus sales (domestic sales):** These sales depend on system storage, generating unit availability, energy availability as well as market conditions. They are impacted by system dispatch decisions.
- **Cost of market electricity purchases (domestic purchases):** These purchases depend on system storage, generating unit availability, energy availability as well as market conditions. They are impacted by system dispatch decisions.
- **Revenue from Columbia River Treaty related agreements:** These revenues depend on non-Treaty water release decisions, Columbia system dispatch decisions, hydrological conditions in the Columbia basin, and market conditions. They are impacted by system dispatch decisions.
- **Cost of water rentals:** These costs depend on the generation output of the heritage assets. They are impacted by system dispatch decisions.
- **Cost of natural gas for thermal generation:** These costs depend on the generation output at BC Hydro’s Prince Rupert and Fort Nelson generation facilities. They are impacted by system dispatch decisions.
- **Cost of Net Purchases (Sales) from Powerex:** These purchases (sales) represent modeled market energy transactions based on a forecast of trade opportunities, which are allocated to Powerex.

4.4.4 The Energy Study Optimizes the Use of System Storage

The Energy Study optimizes the use of System Storage with imports and exports to meet load requirements.

BC Hydro’s primary sources of seasonal and multi-year operational flexibility are Kinbasket reservoir on the Columbia River and Williston reservoir on the Peace River. The total storage capacity in these two reservoirs represents approximately 90 per cent of the total storage in BC Hydro’s system, and together are referred to as System Storage.

These large reservoirs typically reach their minimum storage levels near the end of April, after the annual drawdown to serve winter load and prior to spring freshet. In some years water is withdrawn from System Storage and in other years water is stored. As a result the System Storage, expressed as an energy equivalent, can vary at the end of each fiscal year as shown in Table 4-1 below.

The Energy Study optimization accounts for the efficiency gains made by operating our generating stations at higher reservoir levels. It also models dispatch decisions in response to a range of inflows, market prices, and loads.

Table 4-1 End of Fiscal Year System Storage

GWh	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
End of Period System Storage[122]	11,918	13,208	10,746	9,736	10,576	7,293	9,354	10,649

4.5 Overall Cost of Energy Forecast

This section provides BC Hydro's forecast Cost of Energy, presented in the Gross View, for the test period. Sections 4.6, 4.7 and 4.8 below provide a more detailed breakdown of energy costs by category (Heritage, Non-Heritage and Market) to help clarify the drivers and facilitate comparisons to the previous test period.

BC Hydro's Cost of Energy forecast is shown in Table 4-2 below.

122 System storage is the energy equivalent storage available at the end of each fiscal year at Williston and Kinbasket reservoirs. The system storage forecast is calculated by taking the fiscal 2018 ending storage and adding the forecast net changes in storage year over year.

Table 4-2 Cost of Energy Forecast (Integrated System and Non-Integrated Areas)

Cost of Energy ($millions)	Schedule Reference[123]	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast[124]	F2020 Plan	F2021 Plan
Heritage Energy	4.0 L28	363.8	354.4	341.5	309.0	349.0	299.3	350.9	350.8
Non-Heritage Energy	4.0 L33	1,269.6	1,249.7	1,407.2	1,351.1	1,476.5	1,365.1	1,576.3	1,641.1
Market Energy	4.0 L38	(84.1)	(98.7)	(90.8)	(121.5)	(62.6)	9.0	(40.2)	(71.7)
Total	4.0 L39	1,549.3	1,505.5	1,657.8	1,538.7	1,762.9	1,673.4	1,887.0	1,920.2

Overall, by fiscal 2021, BC Hydro's total Cost of Energy is forecast to increase by $157 million from the fiscal 2019 RRA amount. This forecast increase is primarily driven by an increase in Non-Heritage Energy costs related to IPPs and Long-Term Commitments. Section 4.7.1 describes these cost forecast increases in more detail.

4.5.1 Regardless of Forecast Cost of Energy, Customers Only Pay the Actual Cost

BC Hydro's revenue requirements are based on a forecast Cost of Energy but customers only pay the actual costs. It is recognized that BC Hydro's costs of energy will vary from planned amounts for a number of reasons including weather, water inflows, timing of delivery, and market conditions. Accordingly, the BCUC has approved mechanisms to address variances and ensure that customers only pay for the actual energy costs.

Regulatory accounts are in place to manage the expected variances. Variances between planned and actual costs of energy are deferred to either the Heritage Deferral Account or the Non-Heritage Deferral Account. The Non-Heritage Deferral account also captures the variances between planned and actual domestic customer load, referred to as the Domestic Revenue Variance. The balances in these accounts are amortized into rates in subsequent years in a manner approved by the

[123] Schedule Reference for all tables refers to the location of the original source of the data in Appendix A.
[124] Fiscal 2019 Forecast refers to BC Hydro's forecast values expected at the end of fiscal 2019 as forecast in the October 2018 Energy Study. The Application is submitted prior to the conclusion of the fiscal year, so actual values are not available.

BCUC. The scope of the Heritage and Non-Heritage Deferral Accounts are discussed further in Chapter 7, section 7.7.1.

As a result of BC Hydro's request to refund the fiscal 2019 closing balance in the Heritage Deferral Account and the Non-Heritage Deferral Account to ratepayers in fiscal 2020 and fiscal 2021, the Cost of Energy to be recovered in rates (i.e., the Current View) is forecast to be approximately $152 million lower in each year of the test period.

The one exception to the management of these expected variances is water rentals related to BC Hydro's two-thirds interest in Waneta, which is subject to a lease agreement with Teck as discussed in section 4.2.3. Consistent with BCUC Order No. G-130-18, these variances are not deferred as Teck is responsible for the water rental payments. As a result, ratepayers are not responsible for variances between actual and planned water rental costs related to the two-thirds interest in Waneta during the term of the lease agreement.

4.6 Cost of Heritage Energy

Table 4-3 below provides a detailed breakdown of the forecast Cost of Heritage Energy. These cost components are expected to be relatively steady during the test period.

Table 4-3 Cost of Heritage Energy

($ millions)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Water Rentals	4.0 L23	386.7	387.0	356.8	361.6	356.4	361.8	343.1	349.1
Natural Gas for Thermal Generation	4.0 L24	14.9	9.5	10.5	3.4	10.7	7.6	8.1	8.5
Domestic Transmission - Other	4.0 L25	22.6	22.5	22.3	22.5	22.1	22.6	22.5	22.4
Columbia River Treaty Related Agreements	4.0 L26	(23.1)	(23.3)	(10.4)	(40.6)	(7.2)	(59.5)	3.3	(2.5)
Remissions and Other	4.0 L27	(37.3)	(41.3)	(37.8)	(38.0)	(33.1)	(33.3)	(26.1)	(26.8)
Total	4.0 L28	363.8	354.4	341.5	309.0	349.0	299.3	350.9	350.8

Each item in Table 4-3 is discussed in more detail below. Please refer to Appendix G, section 4 for an explanation of historical variances.

4.6.1 Water Rentals Are a Function of Generation

Water rental fees on the generation of energy are calculated as the actual energy output of the licence holder from the prior calendar year multiplied by the current year water rental rates. The current year rates are calculated as the previous year rate times the annual percentage change in B.C.'s Consumer Price Index. There are two tiers of water rental rates charged by the Government of B.C., which vary depending on the volume of energy produced.

Plant capacity charges are fees paid on the operating capacity and construction capacity of a plant. Water rental fees on operating capacity are calculated as the maximum sustained capacity observed for the current year times the current year rate. These rates are calculated as the previous year rate times the annual percentage change in B.C.'s Consumer Price Index.

For new projects, the nameplate capacity of the generation facility's turbine units is used until a higher peak capacity is observed over a reporting year. Nameplate capacity is the designed maximum output of a generating unit.

Construction capacity is a portion of the nameplate or increased capacity that has not been placed in service. Fees are calculated based on the observed/nameplate capacity for the current year times the current year rate.

Table 4-4 below provides a detailed breakdown of actual and forecast water rental rates.

Table 4-4 Water Rental Rates

Water Rental: General Power Use	Calendar Year				
	Actual		Forecast		
	2017	2018	2019	2020	2021
Output (Tier 1) ($/MWh) < 160,000 MWh	1.339	1.367	1.404	1.436	1.465
Output (Tier 2) ($/MWh) < 3,000,000 MWh	6.243	6.374	6.546	6.697	6.831
Output (Tier 3)[125]	6.560	N/A	N/A	N/A	N/A
Operating Capacity ($/kW)	4.461	4.555	4.678	4.786	4.882
Construction Capacity ($/kW)	0.446	0.455	0.467	0.478	0.488
B.C. CPI (%)	2.1	2.7	2.3	2.0	2.0

Total water rental fees are forecast to be $343.1 million in fiscal 2020 and $349.1 million in fiscal 2021. This includes water rental fees paid on the generation output and capacity of the heritage assets, including BC Hydro's one-third interest in the Waneta generation facility.

Table 4-5 Water Rentals

($ millions)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Water Rentals	4.0 L23	386.7	387.0	356.8	361.6	356.4	361.8	343.1	349.1

4.6.2 Natural Gas for Thermal Generation is Forecasted to Decrease

Table 4-6 provides a detailed breakdown of the forecast costs of natural gas, gas transportation, carbon tax, motor fuel tax and other costs associated with BC Hydro's Prince Rupert and Fort Nelson generation facilities.

125 The Tier 3 rate was eliminated on January 1, 2018. The Tier 3 rate for calendar 2017 was $7.511/MWh for January 1, 2017 to March 31, 2017 and $6.243/MWh for April 1, 2017 to December 31, 2017, charged on a pro-rated basis for the calendar year as $6.560/MWh.

Table 4-6 Natural Gas for Thermal Generation

($ millions)	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Fort Nelson	9.0	2.9	10.5	3.0	10.7	7.0	8.1	8.5
Rupert	0.1	0.7	0.0	0.5	0.0	0.6	0.0	0.0
Burrard[126]	5.9	5.9	0.0	0.0	0.0	0.0	0.0	0.0
Total	14.9	9.5	10.5	3.4	10.7	7.6	8.1	8.5

Total costs of natural gas for thermal generation are forecast to be $8.1 million in fiscal 2020 and $8.5 million in fiscal 2021, compared to $10.7 million for fiscal 2019. This decrease is primarily due to lower forecast gas prices at Station 2[127], which BC Hydro uses to forecast natural gas costs at Fort Nelson.

Total costs of natural gas for the Prince Rupert facility are forecast to be zero in fiscal 2020 and fiscal 2021. This is because the Prince Rupert facility only runs for testing or to supply area load when the transmission line to Prince Rupert is out of service. Therefore, it is not modelled in the Energy Study and its actual costs will vary from forecast.

4.6.3 Domestic Transmission – Other: Forecast Costs are Stable

Table 4-7 Domestic Transmission – Other

($ millions)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Domestic Transmission - Other	4.0 L25	22.6	22.5	22.3	22.5	22.1	22.6	22.5	22.4

The costs included under Domestic Transmission – Other are only for transmission costs related to the delivery of energy to the City of Seattle under the Skagit River Valley Treaty. The costs are quite stable from year to year, and include approximately $16 million per year for wholesale transmission in British Columbia, to deliver energy to the B.C./U.S. border, and approximately $6 million per year for

126 Burrard Thermal Generating Station’s costs are forecast during the test period to be zero. This facility is now only used for grid reliability purposes as a synchronous condense facility, and is not used as a generating resource.

127 Station 2 is a gas transportation hub near Chetwynd, and is the nearest liquid market to Fort Nelson with valid forward gas pricing.

wholesale transmission in the United States, to deliver energy from the B.C./U.S. border to the City of Seattle.

These domestic transmission costs to deliver energy to the BC/US border (i.e., $16 million per year) are included in BC Hydro's Transmission Revenue Requirement (**TRR**) and are recovered under the Open Access Transmission Tariff (**OATT**). These costs represent BC Hydro's use of point-to-point transmission service for the Skagit River Valley Treaty. In the TRR, these costs are allocated to Cost of Energy via intersegment revenues which are reported in Appendix A, Schedule 3.4, line 18. This allocation of intersegment revenues ensures that costs are only recovered from ratepayers once.

4.6.4 Columbia River Treaty Related Agreements Revenue is Driven by Coordinated Operations

Table 4-8 Columbia River Treaty Related Agreements

($ millions)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Columbia River Treaty Related Agreements	4.0 L26	(23.1)	(23.3)	(10.4)	(40.6)	(7.2)	(59.5)	3.3	(2.5)

The Non-Treaty Storage Agreement[128] and a short-term coordination agreement related to the Libby Coordination Agreement[129] are coordination agreements related to the operation of the Columbia River Treaty reservoirs in Canada. These agreements are water coordination agreements that provide for the release and storage of water to create mutual operational benefits in both Canada and the United States. The agreements are designed to create an average annual positive financial benefit to BC Hydro. The forecast revenue in fiscal 2020 and fiscal 2021 is less than the fiscal 2019 forecast because of high water releases that occurred in July and August 2018 to take advantage of high market prices.

[128] See footnote 101.
[129] See footnote 102.

4.6.5 Remissions and Other Serve to Offset Water Rental Costs

In cases where Water Use Planning requirements[130] are incremental to the requirements under BC Hydro's existing water licences, BC Hydro is entitled to recover the associated incremental costs through a reduction in water rentals. This amount is referred to as Remissions. The Government of B.C. caps Water Use Planning Remissions at $50 million per calendar year, with any excess associated with physical works carried into a future year.

Table 4-9 Water Use Planning Remissions

($ millions)	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Remissible portion for Monitoring and Physical Works (Offset in Operating Costs)	(15.3)	(12.1)	(18.4)	(11.2)	(10.7)	(13.7)	(10.2)	(8.2)
Remissible portion for Value of Foregone Energy (Offset in Cost of Energy)	(37.3)	(41.3)	(37.8)	(38.0)	(33.1)	(33.3)	(26.1)	(26.8)
Total Credited Remissions	(52.6)	(53.4)	(56.2)	(49.2)	(43.8)	(47.0)	(36.4)	(35.1)

Water Use Planning Remissions include:

- Remissions associated with the value of foregone energy, which are shown as a credit under Cost of Energy; and
- Remissions associated with the delivery of monitoring and physical works programs, which are shown as a credit under operating costs (see Chapter 5B, section 5B.6.2.5).

Total forecast Remissions associated with the value of foregone energy (offset in Cost of Energy) are forecast to be around $26 million for fiscal 2020 and fiscal 2021. The forecast decrease for Water Use Planning Remissions in the test period, as compared to fiscal 2019 RRA Plan, is largely due to lower remissions collected at Bridge River and John Hart. The re-development project at John Hart resulted in a

[130] The Water Use Planning program was initiated by BC Hydro in November 1998. Delivery of BC Hydro's Water Use Plan requirements are included in Orders by the Comptroller of Water Rights.

change to licence conditions, and the anticipated water license renewal[131] at Bridge River is expected to result in a change to BC Hydro's eligibility for Remissions.

Remissions are shown in Schedule 4.0, line 27 of Appendix A. The Other items included within line 27 are the funds paid annually to the Skagit Environment Endowment Fund (approximately $0.07 million), consistent with commitments related to the Skagit River Valley Treaty.

4.7 Cost of Non-Heritage Energy

Table 4-10 below provides a detailed breakdown of the Cost of Non-Heritage Energy. The cost increases over the test period are driven by increases in the forecast cost of IPPs and Long-Term Commitments. Each element of the cost of Non-Heritage Energy is discussed in the sections that follow.

Table 4-10 Cost of Non-Heritage Energy

Cost of Energy	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F202 Plan
IPPs and Long-Term Commitments[132]	4.0 L29	1,234.4	1,213.1	1,369.7	1,311.6	1,439.3	1,326.6	1,538.5	1,601.1
Non-Integrated Area	4.0 L30	24.6	25.0	27.4	26.5	31.1	26.9	31.6	33.6
Gas & Other Transportation	4.0 L31	10.6	11.7	10.1	13.1	6.1	9.2	2.8	2.7
Water Rentals (Waneta Two-Thirds)	4.0 L32	0.0	0.0	0.0	0.0	0.0	2.4	3.5	3.7
Total	4.0 L33	1,269.6	1,249.7	1,407.2	1,351.1	1,476.5	1,365.1	1,576.3	1,641.1

The cost of Non-Heritage Energy includes cost associated with EPAs for the integrated system and the non-integrated area. As of October 2018, BC Hydro has 133 active EPAs with IPPs.[133] This includes 124 projects that are in commercial operation and delivering energy as well as nine projects that are in various phases of development and have not yet reached commercial operation.

131 BC Hydro is in the process of renewing several water licenses that expire or are set to expire at Bridge, Alouette and Wilsey dams. BC Hydro has submitted a renewal application and a Project Development Plan to the Comptroller of Water Rights.

132 These values are after accounting adjustments.

133 Since October 2018, two more EPAs have expired and not been renewed. Please refer to footnote 15.

4.7.1 IPPs and Long-Term Commitments Costs are Largely Prescribed

For the integrated system, there are 119 projects in commercial operation and eight projects in development with existing EPAs. Costs for EPAs on the integrated system are categorized under “IPPs and Long-Term Commitments”.

Table 4-11 IPPs and Long-Term Commitments

Cost of Energy	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
IPPs and Long-Term Commitments[134]	4.0 L29	1,234.4	1,213.1	1,369.7	1,311.6	1,439.3	1,326.6	1,538.5	1,601.1

These forecast costs are primarily associated with existing EPAs, and because the terms of these agreements are already set, the forecast costs for these EPAs are largely prescribed. With few exceptions, BC Hydro is not acquiring new resources from IPPs. Those exemptions represent only a very small portion of the forecast Cost of Energy.

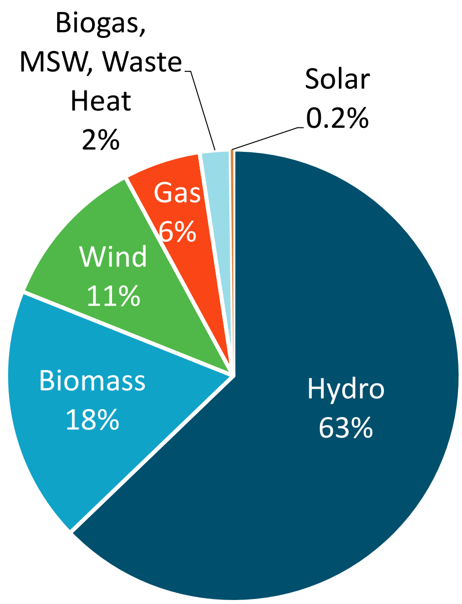
4.7.1.1 Cost of IPP Energy Reflects Long-Term Acquisitions Undertaken Over Many Years

The forecast cost of IPP energy in the test period reflects long-term EPA commitments that occurred over a number of years. BC Hydro has purchased electricity from IPPs since the mid-1980s and the average contract term for an EPA is 28 years.

The electricity supplied by IPPs on BC Hydro’s integrated system is approximately 25 per cent of BC Hydro’s electricity supply and helps to meet BC Hydro’s load requirements. IPP projects are developed by companies specializing in power production, as well as by municipalities, First Nations and BC Hydro customers, using resources such as wind, water, biomass, solar and waste heat. Figure 4-1 provides a breakdown of fiscal 2021 forecast energy volumes by resource type for the integrated system.

[134] These values are after accounting adjustments.

Figure 4-1 Breakdown of IPP Purchase Volumes by Resource Type (Percentage, F2021 Plan, Integrated System)



BC Hydro has entered into EPAs with IPPs through competitive calls, standing offers and bilateral negotiations. These various procurement processes have enabled BC Hydro to acquire resources to meet energy need identified at the time of the procurement. Table 4-12 below outlines BC Hydro's EPA volumes from each procurement process. As discussed in section 4.3.2, BC Hydro has been pursuing the renewal of expiring EPAs to meet future long-term energy needs and has renewed contracts with IPPs at lower prices than under their original contracts, through bilateral negotiations. The volume associated with each EPA renewal is included in the total for its original procurement call process.

Table 4-12 IPP and Long-Term Purchase Volumes for the Integrated System (October 2018 Forecast)

Call Process GWh	Number of EPAs[1]	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Pre 2003 EPAs[2]	31	3,307	3,498	3,350	3,315	3,139	3,289	3,301	3,350
2003 Green Power Generation Call	6	562	591	562	557	562	565	566	566
2006 Open Call	17	2,129	2,235	2,135	2,132	2,135	2,136	2,178	2,178
2008 Bioenergy Call - Phase 1	2	188	199	188	191	188	161	204	216
2008/10 Standing Offer Program	26	295	293	431	338	517	407	486	522
2010 Bioenergy Call - Phase 2	4	282	151	725	209	725	568	680	680
2010 Clean Power Call	20	1,818	1,649	2,705	2,414	2,863	2,647	2,779	2,867
2010 Integrated Power Offer	7	1,022	1,040	1,064	1,012	1,074	1,052	1,175	1,145
Negotiated EPAs[3]	14	3,700	3,989	3,712	4,185	3,703	3,801	4,010	4,369
Expected SOP Projects and other First Nations Commitments[4]	7	71	-	130	-	291	6	70	149
Total	134	13,375	13,644	15,002	14,354	15,199	14,631	15,449	16,040

1 Number of EPAs with IPPs on the integrated system (as of October 1, 2018).
2 The volumes in this row also include miscellaneous energy purchases, such as energy purchases for border accommodations.
3 The volumes in this row also include two other energy supply contracts which are not considered to be IPP EPAs. These are the Surplus Power Rights Agreement between Teck and BC Hydro and the Residual Capacity Agreement between FortisBC and BC Hydro.
4 The volumes shown are expected volumes for future EPAs. Once an EPA is executed, the volumes are included in the appropriate call process. BC Hydro notes that the F2017-F2019 Plan values include forecast costs from the Standing Offer Program, and one co-generation project. This co-generation project is no longer going ahead and is not included as part of the forecast for the test period.

As shown in Figure 4-1, BC Hydro's EPA portfolio includes a significant amount of hydro generation. The amount of generation under these contracts is driven by water inflows and other operational factors which may cause actual energy deliveries to vary significantly from year to year. Appendix G provides a description of IPP volume and cost variances for fiscal 2017 and fiscal 2018.

To provide reporting consistency with previous Revenue Requirement applications, Table 4-13 provides the cost of IPP energy before and after accounting adjustments.

Table 4-13 Breakdown of IPP and Long-Term Commitments for the Integrated System (October 2018 Forecast)

Call Process ($ millions)	Number of EPAs[1]	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Pre 2003 EPAs[2]	31	277.2	287.3	281.0	276.1	261.6	261.9	268.5	276.3
2003 Green Power Generation Call	6	33.3	34.9	33.7	32.9	34.1	34.0	34.6	35.0
2006 Open Call	17	188.4	187.5	190.8	187.2	192.7	184.5	196.9	199.0
2008 Bioenergy Call - Phase 1	2	22.7	22.0	23.0	25.0	23.3	21.7	24.4	20.1
2008/10 Standing Offer Program	26	28.9	28.2	43.8	33.2	52.6	41.8	50.5	54.4
2010 Bioenergy Call - Phase 2	4	39.2	20.2	99.7	29.6	100.9	83.0	98.3	99.6
2010 Clean Power Call	20	242.0	213.0	336.0	296.4	358.3	318.6	353.7	367.6
2010 Integrated Power Offer	7	126.5	128.4	131.2	127.1	135.1	138.0	156.9	149.8
Negotiated EPAs[3]	14	346.5	353.2	357.1	374.2	359.9	349.9	381.2	416.0
Expected SOP Projects and other First Nations Commitments[4]	7	7.8	-	13.6	-	29.2	0.7	8.1	16.4
Total IPP Purchase Costs	134	1,312.5	1,274.7	1,509.9	1,381.7	1,547.9	1,434.3	1,573.2	1,634.3
Accounting Adjustments		(78.1)	(61.6)	(140.2)	(70.1)	(108.6)	(107.8)	(34.7)	(33.2)
IPPs and Long-Term Commitments	134	1,234.4	1,213.1	1,369.7	1,311.6	1,439.3	1,326.6	1,538.5	1,601.1

1 Number of EPAs with IPPs on the integrated system (as of October 1, 2018).

2 The costs in this row also include miscellaneous energy purchases, such as energy purchases for border accommodations.

3 The costs in this row also include two other energy supply contracts which are not considered to be IPP EPAs. These are the Surplus Power Rights Agreement between Teck and BC Hydro and the Residual Capacity Agreement between FortisBC and BC Hydro.

4 The costs shown are expected costs for future EPAs. Once an EPA is executed, the costs are included in the appropriate call process. BC Hydro notes that the F2017-F2019 Plan values include forecast volumes from the Standing Offer Program, and one co-generation project. This co-generation project is no longer going ahead and is not included as part of the forecast for the test period.

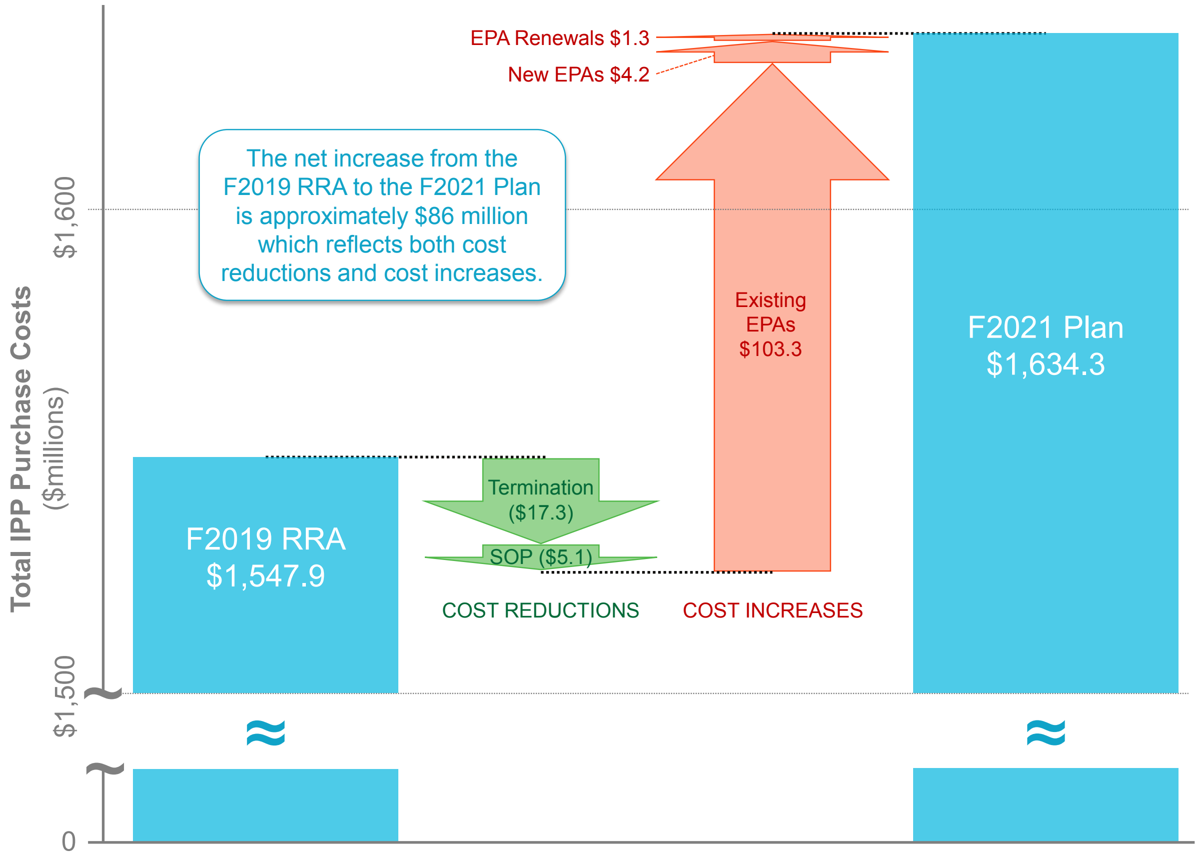
The Accounting Adjustments shown in Table 4-13 largely reflect energy costs for EPAs which are accounted for as capital leases under the current accounting standards. For those EPAs that are deemed to be capital leases, for accounting purposes, their costs are recorded as operating costs, taxes, amortization, finance charges as well as Cost of Energy. The decrease in Accounting Adjustments from the fiscal 2019 forecast is due to a new accounting standard effective for fiscal 2020 (as further discussed in Chapter 8, section 8.12.1 and 8.13.3). Prior to this new accounting standard, three EPAs were recognized as capital leases. As of fiscal 2020, under the new accounting standard, these three EPAs are no longer accounted for as leases, and one EPA, previously included in Cost of Energy, will be accounted for as a lease.

4.7.1.2 Increase in IPP Costs is Largely Associated With Existing Contracts, Not New Resource Acquisitions

The majority of IPP forecast cost increases from fiscal 2019 to fiscal 2021 are related to existing EPAs. BC Hydro is not acquiring new resources from IPPs (other than a small number of new First Nations energy projects and some EPA renewals).

The increase in total IPP purchase costs from fiscal 2019 RRA to fiscal 2021 Plan is forecast to be 5.6 per cent. During the test period, for each EPA, there may be a number of factors which may cause the forecast costs to either increase or decrease, such as a change in operation as may be allowed under the EPA and price escalation. As shown in Figure 4-2, on a net basis, the total forecast IPP cost (for the integrated system and before accounting adjustments) is increasing by approximately $86 million by fiscal 2021.This estimate reflects both cost increases and cost reductions, as more fully described below.

Figure 4-2 Breakdown of Total IPP Purchase Cost Forecast Increases from Fiscal 2019 RRA to Fiscal 2021[135]



The forecast net cost increases during the test period are generally attributed to the following factors:

- **Existing EPAs:** This net increase takes into consideration operational changes at IPP facilities or other changes, as permitted under existing agreements, which may impact the forecast cost of IPP energy. For example, these types of changes would include price escalation, capacity increases, and forecast delivery changes resulting from a partial-year forecast becoming a full-year forecast. BC Hydro notes that variances in historical energy deliveries can be

[135] The increase of $86 million as shown in Figure 4-2 is before accounting adjustments. As show in Table 4-13, the increase after accounting adjustments during the test period is $161.8 million (fiscal 2021 when compared to F2019 RRA). Section 4.7.1.1 describes the accounting adjustments during the test period.

positive or negative and such variances may impact forecast IPP energy volumes. Of the $103.3 million increase, more than half can be attributed to increased forecast deliveries from two IPP facilities as permitted under their respective agreements.

- **New EPAs:** This represents the forecast costs from IPPs with new EPAs signed since the Previous Application (e.g., under the SOP) that are forecast to achieve commercial operation prior to the end of the test period.
- **EPA Renewals:** This represents the net change in cost (i.e., certain new EPAs to replace existing expiring EPAs are forecast to increase in cost and others are forecast to decrease) from the fiscal 2019 RRA to the fiscal 2021 Plan of those EPAs that have been renewed since the Previous Application and those EPAs that are assumed to be renewed during the test period. This net increase includes the costs of expiring EPAs, the costs for hydro renewals and the costs associated with the Biomass Energy Program.

The forecast net cost reductions in IPP costs during the test period are generally attributed to the following factors:

- **Terminations:** This includes terminations of EPAs, EPAs which have expired and have not been renewed, and one cogeneration project that is no longer going ahead and has been removed from the forecast.
- **SOP Reductions:** This reflects the reduction in forecast energy volumes for the SOP due to the indefinite suspension of the program.

4.7.2 Non-Integrated Area Forecast Increases Are Driven by Diesel Costs

Non-Integrated Area communities are served by local generating facilities and distribution networks. There are two types of costs in serving these communities: costs for BC Hydro's diesel generating facilities and IPP costs for five hydro facilities[136] and one biomass facility.

Table 4-14 Non-Integrated Area Generation Costs

Non-Integrated Area ($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
NIA – BC Hydro Diesel Generating Stations		15.4	15.0	18.5	16.3	22.0	18.0	21.3	23.5
NIA - IPPs		9.2	9.9	8.8	10.2	9.2	8.8	10.2	10.1
Total	4.0 L30	24.6	25.0	27.4	26.5	31.1	26.9	31.6	33.6

As compared to fiscal 2019 RRA Plan, during the test period, energy volumes are relatively stable. Variations in forecast costs for fiscal 2020 and fiscal 2021 are largely driven by fluctuations in fuel prices for BC Hydro's diesel generation facilities. Fuel prices are based on the Annual Energy Outlook Report issued by the U.S. Energy Information Administration. To the extent that diesel prices ultimately depart from the forecast prices, the variance will be captured in a regulatory account.

In Non-Integrated Area communities, existing and planned IPPs may displace a portion of diesel generation. However, diesel generation facilities must be in place for reliability purposes in all 14 Non-Integrated Areas.

4.7.3 Gas and Other Transportation Costs Have Decreased

Gas and other transportation costs are forecast to diminish significantly for the test period.

136 Four of the five hydro facilities have reached commercial operation and one is forecast to reach commercial operation.

Table 4-15 Gas and Other Transportation

Cost of Energy	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Gas & Other Transportation	4.0 L31	10.6	11.7	10.1	13.1	6.1	9.2	2.8	2.7

Gas transportation costs include upstream gas transportation contracts entered into by BC Hydro (not included with IPP and Long-Term Commitments or as part of BC Hydro's Cost of Heritage Energy) and fuel costs related to a dispatch agreement for firm capacity and associated energy. In fiscal 2019, BC Hydro had only one upstream gas transportation contract included in Gas and Other Transportation (Schedule 4.0, line 31 of Appendix A). This contract was assigned to Powerex in November 2018 as the need for gas supply has greatly diminished due to the change in operation of thermal generating facilities, primarily related to the decommissioning of Burrard Thermal.

BC Hydro also incurs external electricity transmission costs, including those related to the service of domestic load in Fort Nelson from energy imported from Alberta, as well as wheeling charges to serve the domestic load in the Goodlow (Boundary Lake), Rogers Pass, and Duck Lake areas.

Total forecast gas and external transmission costs for fiscal 2020 and fiscal 2021 are $2.8 million and $2.7 million respectively, compared to the fiscal 2019 Plan of $6.1 million. This decrease largely reflects the assignment of BC Hydro's gas transportation contract to Powerex.

4.7.4 Water Rentals (Waneta Two-Thirds) are Paid by Teck

Table 4-16 Water Rentals (Waneta (Two-Thirds)

Cost of Energy	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Water Rentals (Waneta Two-Thirds)	4.0 L32	0.0	0.0	0.0	0.0	0.0	2.4	3.5	3.7

As discussed in section 4.2.4, BC Hydro's two-third interest in Waneta is leased to Teck. Teck is responsible for all operating costs, including paying for its share of water rentals. These costs are shown as an offset in Miscellaneous Revenues (Appendix A, Schedule 15.0, line 22).

4.8 Cost of Market Energy

Cost of Market Energy includes domestic and trade energy purchases and sales. Domestic purchases and sales fall under Market Electricity Purchases and Surplus Sales respectively; and trade purchases and sales fall under Net Purchases (Sales) from Powerex. The use of BC Hydro's transmission system for export related to Surplus Sales is referred to as Domestic Transmission – Export.

Table 4-17 Cost of Market Energy

($ millions)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Market Electricity Purchases	4.0 L34	8.6	3.4	30.2	3.7	35.9	89.1	40.0	18.2
Surplus Sales	4.0 L35	(118.1)	(132.8)	(150.4)	(139.4)	(129.2)	(115.0)	(97.1)	(111.4)
Net Purchases (Sales) from Powerex	4.0 L36	(6.5)	2.3	(6.0)	(10.9)	0.7	16.4	(0.5)	0.5
Domestic Transmission – Export	4.0 L37	31.8	28.3	35.4	25.2	29.9	18.5	17.4	21.0
Total	4.0 L38	(84.1)	(98.7)	(90.8)	(121.5)	(62.6)	9.0	(40.2)	(71.7)

4.8.1 Market Electricity Purchases

Table 4-18 Market Electricity Purchases

($ millions)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Market Electricity Purchases	4.0 L34	8.6	3.4	30.2	3.7	35.9	89.1	40.0	18.2

Market Electricity Purchases are the amount of electricity purchases allocated to BC Hydro to serve domestic load in a given year, and vary depending on reservoir inflows, market prices, and customer demand. These purchases are performed exclusively with Powerex, and the energy is provided to BC Hydro in accordance with the applicable transfer price. While BC Hydro is in an energy surplus position, Market Electricity Purchases are required, at certain times during the year, to meet domestic load requirements during short-term operational constraints.

The cost of planned market electricity purchases for fiscal 2020 and fiscal 2021 are based on forward market prices as of October 15, 2018. Total market electricity purchases are based on the results of BC Hydro's Energy Study described in section 4.4.2.1, and are expected to be 1,504 GWh in fiscal 2020 and 648 GWh in fiscal 2021.

Unlike Powerex's trade activity, which is captured under Net Purchases (Sales) from Powerex, Market Electricity Purchases are not net of Surplus Sales, which is discussed in the next section.

4.8.2 Surplus Sales

Table 4-19 Surplus Sales

($ millions)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Surplus Sales	4.0 L35	(118.1)	(132.8)	(150.4)	(139.4)	(129.2)	(115.0)	(97.1)	(111.4)

Surplus Sales are sales of electricity when BC Hydro has energy that is surplus to domestic load requirements. BC Hydro may also sell energy to the market in response to system conditions, such as excess freshet energy. As with Market Electricity Purchases, these sales are performed exclusively with Powerex, and the energy is provided to Powerex in accordance with the applicable transfer price.

Surplus Sales are expected to be 2,409 GWh in fiscal 2020 and 3,087 GWh in fiscal 2021. These amounts are lower than the fiscal 2019 RRA Plan amount due to expected filling of system storage in the test period as shown in Table 4-1 as well as increased load requirements, as shown in the Load Forecast discussed in Chapter 3.

4.8.3 Net Purchases (Sales) from Powerex

Table 4-20 Net Purchases (Sales) from Powerex

($ millions)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Net Purchases (Sales) from Powerex	4.0 L36	(6.5)	2.3	(6.0)	(10.9)	0.7	16.4	(0.5)	0.5

As discussed in section 4.2.4, Powerex may elect to purchase energy from BC Hydro when the system has flexibility for energy to be drawn from storage, and to sell energy to BC Hydro when the system has flexibility for energy to be stored. Such transactions are undertaken to take advantage of market trading opportunities.

When Powerex acquires energy from BC Hydro, it seeks to maximize value of this energy in external markets. The difference between the transfer price paid by Powerex to BC Hydro for that energy and the revenue (net of operating costs) ultimately received by Powerex for that energy is included in Powerex's net income. Powerex's net income is applied as an offset to BC Hydro's overall revenue requirements.[137]

However, for the purposes of this application, Net Purchases (Sales) from Powerex are based on the modelling results of BC Hydro's Energy Study described in section 4.4.2.1 and are net of the quantities assigned to Market Electricity Purchases and/or Surplus Sales. They are modelled to be 177 GWh in fiscal 2020 and 90 GWh in fiscal 2021. Although for fiscal 2020 and fiscal 2021 the Net Purchases from Powerex (GWh) indicates a net import of energy for each fiscal year, the net dollar value may be positive (cost to BC Hydro) or negative (revenue to BC Hydro) because of variations in the forecast market value of energy.

[137] BC Hydro forecasts Powerex's net income based on its historical five year average. The difference between forecast Powerex net income and actual Powerex net income is deferred to the Trade Income Deferral Account. However, if Powerex's net income is less than zero, the amount deferred to the Trade Income Deferral Account is the difference between zero and the forecast amount.

4.8.4 Domestic Transmission – Export

Table 4-21 Domestic Transmission – Export

($ millions)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Domestic Transmission – Export	4.0 L37	31.8	28.3	35.4	25.2	29.9	18.5	17.4	21.0

The use of BC Hydro's transmission system for export related to Surplus Sales pursuant to the OATT is referred to as Domestic Transmission – Export. These costs are determined based on the forecast percentage of domestic energy exports relative to the total domestic and trade exports, using the historical average unit cost for domestic exports.

Domestic Transmission - Export costs are expected to be $17.4 million in fiscal 2020 and $21.0 million in fiscal 2021. These amounts are lower than the fiscal 2019 RRA Plan amount due to a lower volume of Surplus Sales, as described in section 4.8.2.

Domestic Transmission - Exports costs are included in BC Hydro's TRR and are recovered under the OATT. These costs represent BC Hydro's use of point-to-point transmission service for domestic exports. In the TRR, these costs are allocated to Cost of Energy via intersegment revenues which are reported in Appendix A, Schedule 3.4, line 18. This allocation of intersegment revenues ensures that costs are only recovered from domestic customers once.

Fiscal 2020 to Fiscal 2021

Revenue Requirements Application

Chapter 5

Operating Costs

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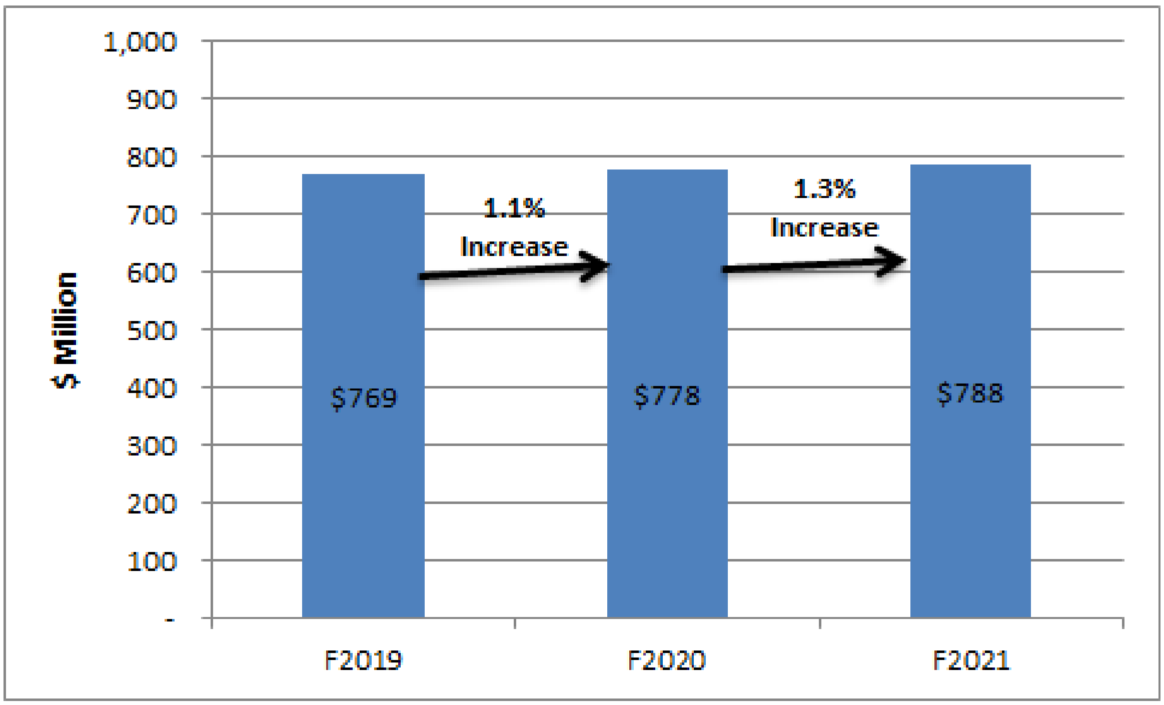
5.1 Introduction

This chapter describes our planned operating costs and full time equivalents (**FTEs**) for the fiscal 2020 to fiscal 2021 test period. As shown in Figure 5-1 below, BC Hydro is limiting base operating cost increases[138] below the forecast rate of inflation[139] over the test period.

Figure 5-1 Base Operating Cost Increases Are Below Forecast Inflation



BC Hydro has been able to limit base operating cost increases to below the forecast rate of inflation for the test period by partially offsetting non-controllable cost increases with reductions to controllable costs.

138 BC Hydro explains in section 5.5.1 why base operating costs should be the focus.

139 BC Hydro uses the B.C. Consumer Price Index measure for the forecast rate of inflation. The forecast rate of inflation for fiscal 2019, fiscal 2020 and fiscal 2021 is 2.7 per cent, 2.3 per cent and 2.0 per cent, respectively.

Detailed support for BC Hydro's forecast operating costs, by Business Group, are provided in Chapters 5A through 5G. In response to commentary from the BCUC about needing to better understand BC Hydro's operating cost budget, these chapters provide significantly more information than the Previous Application on the operating costs and FTEs for each of BC Hydro's six Business Groups and 39 Key Business Units (**KBUs**). The composition of the entire budget of each KBU, not just the incremental costs, is addressed in these chapters.

This chapter is organized around the following key points:

- Section 5.2 summarizes how BC Hydro has considered and responded to the BCUC's comments and recommendations about BC Hydro's operating costs in its Decision.[140]
- Section 5.3 describes changes to BC Hydro's organizational structure since the Previous Application. We have completed the transition to a centralized and functionally-aligned structure.
- Section 5.4 explains that BC Hydro has a robust budgeting process, with both top-down and bottom-up elements.
- Section 5.5 provides an overview of BC Hydro's operating costs during the test period:
  - ▶ Controllable cost pressures were absorbed within existing budgets, which means that after accounting for Standard Labour Rate increases, most KBUs were held to their current level of spend; [141] and

[140] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 33.

[141] Operating costs for some KBUs may increase or decrease from fiscal 2019 forecast to fiscal 2020 plan, due to budget transfers related to re-organizations. Overall, these transfers are cost neutral.

  - ▶ BC Hydro has achieved reductions in controllable costs through a variety of means, including vacancy factor savings, lease consolidations, and a reduction to advertising costs.
- Section 5.6 provides an overview of BC Hydro's FTEs and Standard Labour Rates:
  - ▶ The Workforce Optimization Program has reduced BC Hydro's total costs by replacing contractors with internal employees;
  - ▶ The repatriation of services previously provided by Accenture has resulted in higher than expected cost savings;
  - ▶ Apart from growth in the workforce directly related to increased capital investment, BC Hydro's FTEs have remained relatively flat since fiscal 2012 and will remain flat during the test period; and
  - ▶ A 2017 assessment by Morneau Shepell concluded that on a total cash basis, BC Hydro's employee compensation is 11 per cent below median market rates. After factoring in the value of pension benefits and time off programs, employee compensation is comparable to median market rates.
- Section 5.7 addresses benchmarking:
  - ▶ A report prepared by The Brattle Group shows that BC Hydro's operating costs[142] benchmark favourably against a peer group of U.S. utilities;
  - ▶ An internal analysis provides an indicative assessment that BC Hydro's operating costs compare well against those of other major Canadian utilities;
  - ▶ Recent benchmarking on maintenance delivery costs has demonstrated that BC Hydro's costs are consistent with or better than its utility peers; and

[142] The Brattle Group Benchmarking Study focused on operations and maintenance costs, excluding the costs of fuel and water rental that are used in the power production process. The Brattle Group Benchmarking Study refers to these costs as "non-fuel operations and maintenance expenses", or by the acronym "NFOM". The costs of fuel and water rentals that are used in the power production process are excluded because they are reflected in BC Hydro's cost of energy. Cost of Energy is addressed in Chapter 4 of the Application.

- ▶ Benchmarking used throughout BC Hydro provides additional comfort that we are managing operating costs appropriately;

- Section 5.8 explains how BC Hydro is optimizing the level of Power System maintenance, successfully mitigating increases in maintenance expenditures in recent years despite a growing Power System asset base, aging assets, and increased regulatory requirements.
- Section 5.9 outlines the content of Chapters 5A to 5G, which provide the composition, drivers and outcomes of each KBU budget in more detail than in the Previous Application.

5.2 We have Addressed the BCUC's Recommendations and Comments on Operating Costs

The BCUC accepted BC Hydro's forecast fiscal 2017 to fiscal 2019 operating costs in its Decision. However, the BCUC also made a number of recommendations and comments related to operating costs, to which BC Hydro has responded in this chapter.

Table 5-1 below sets out the BCUC's recommendations and comments on operating costs, and summarizes our response. It also indicates where further information on BC Hydro's response can be found.

Table 5-1 Response to BCUC Recommendations and Comments on Operating Costs

Topic	BCUC Recommendations / Comments[143]	Location of BC Hydro's Response
Comfort in Cost "Starting Point"	The Panel notes that BC Hydro states that test period increases in base operating costs are forecast to be below the rate of inflation at an average of 1.2 per cent per annum (excluding Smart Metering and Infrastructure Program costs). The Panel recognizes that in some cases, comparing forecast cost increases to the rate of inflation may be considered an appropriate measure for evaluating the reasonableness of forecast cost increases in the test period. This method is likely suitable in situations where a regulator has consistently been empowered to oversee all aspects of the utility's forecast and historical expenditures through proceedings in which the underlying base costs were initially established. However, given the Commission's limited involvement in the approval of BC Hydro's recent revenue requirements, the Panel does not have a high degree of comfort in BC Hydro's starting point, being the 2016 base operating cost.	• Section 5.4 discusses BC Hydro's budgeting process, which incorporates both top-down and bottom-up elements. • Chapters 5A through 5G provide significantly more information on our operating costs and FTEs, relative to the Previous Application. We address the composition, drivers and outcomes of the overall budget of each KBU, not just incremental amounts. • Section 5.7 (and the last row in this table) discusses benchmarking, including independent benchmarking studies on our overall operating and maintenance costs. Compensation benchmarking is addressed in section 5.6.5.

143 BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), pages 34-35 and 87.

Topic	BCUC Recommendations / Comments[143]	Location of BC Hydro's Response
FTE Increases	In the 2011 review of BC Hydro, it was recommended that there be a reduction of staff from the current 6,000 employees to 4,800[144]. In the Application, BC Hydro indicated it had a net reduction of approximately 650 positions in response to the 2011 review recommendations. However at this time, BC Hydro indicates it still has over 5,500 employees and estimates total FTE staffing at 6,296 in fiscal 2017, 6,344 in fiscal 2018 and 6,365 in fiscal 2019.	• Section 5.4.3 sets out BC Hydro's vacancy management process. • Section 5.6.1 explains that BC Hydro's total labour costs have declined. The growth in FTEs in recent years has actually been a source of cost savings. The Workforce Optimization Program, discussed in section 5.6.1, has replaced higher cost contractors with internal FTEs. The Accenture repatriation, discussed in section 5.6.2, has exceeded the anticipated cost savings. • Section 5.6.3 explains that apart from growth in the workforce directly related to increased capital investment, BC Hydro's FTEs have remained relatively flat since fiscal 2012. Section 5.6.4 shows that, excluding the Site C Project, FTEs will remain flat during the test period.
Long-Term Costs of Workforce Optimization	In July 2015, BC Hydro launched the Workforce Optimization Program to examine its resourcing model to determine the right mix of internal and external resources. BC Hydro submits that increased labour costs are supposed to be more than offset by a reduction in capital labour costs associated with contractors. Although BC Hydro reported the elimination of 900 positions, its Workforce Optimization will actually add an additional 170 FTEs through to fiscal 2019. Although short-term savings are anticipated by BC Hydro, there does not appear to be an assessment of the long-term effects and costs of hiring contractors as employees.	• Section 5.6.1.3 explains how long-term effects and costs are taken into consideration in the workforce adjustment request document that is required for any conversions of contractors to internal FTEs under the Workforce Optimization Program.

144 BC Hydro notes that while the panel that conducted the Government of B.C.'s 2011 review of BC Hydro believed that 4,800 employees was a more reasonable staffing level, the actual recommendation in the panel's report was to "accelerate the pace and magnitude of change to develop an organizational structure that reflects the reasonable level of internal and external staffing that reduces costs passed on to ratepayers".

Topic	BCUC Recommendations / Comments[143]	Location of BC Hydro's Response
Work Smart (Use of Capacity Savings)	BC Hydro initiated a Work Smart program which uses Lean methodology to examine internal processes for opportunities to make them more efficient. BC Hydro states these initiatives were implemented across the organization and are reported to have generated an estimated additional employee capacity of 22,500 hours annually. Given these initiatives, in the Panel's view, it should be expected that further efficiency savings should be identifiable in an organization as large as BC Hydro and that there should be incremental cost savings in fiscal 2018 and fiscal 2019. However, the Panel notes that BC Hydro states it has not completed a cost benefit analysis for the initiatives but will instead monitor as it is rolled out to evaluate its effectiveness. The Panel recognizes that while BC Hydro states it is not the intention of Work Smart to reduce costs but rather to allow for the reallocation of staff to more productive purposes, in our view a measured increase in productivity should result in costs savings.	• Section 5.4.5 discusses how capacity has gained through BC Hydro's Work Smart program have exceeded expectations. We also explain that using this capacity to avoid incremental costs by managing workload and absorbing new work is beneficial and consistent with the practice at other companies.
Total Rewards Program	BC Hydro states that based on its 2015 survey, salaries for electric utility jobs are 15 per cent below market rates and general industry jobs are at market. On a total cash (salary plus short term incentives pay) basis, electricity utility jobs are 25 per cent below market rates and general industry jobs are 7 per cent below market rates. To compensate, BC Hydro states that it provides benefits such as time off and the pension program to reduce the gap to market on a total rewards basis. The Panel notes that both the costs and benefits of these initiatives are unclear and should be further examined.	• Section 5.6.5 addresses the value delivered by BC Hydro's Total Rewards Program. Our Total Rewards offer is designed to attract and retain qualified employees and is working. Our voluntary turnover rate is 1.3 per cent, which is below the 3.8 per cent average for the Power and Utilities industry as reported by the Conference Board of Canada. A 2017 assessment by Morneau Shepell concluded that on a total cash basis, BC Hydro employees earn 11 per cent below median market rates. After factoring in the value of pension benefits and time off programs, BC Hydro's employee compensation is comparable to median market rates.

Topic	BCUC Recommendations / Comments[143]	Location of BC Hydro's Response
Use of Benchmarking and Metrics	The Panel is concerned with the lack of metrics used by BC Hydro for productivity or benchmarking purposes.	• Section 5.7.1 summarizes the independent benchmarking study prepared by The Brattle Group for this proceeding, which confirms that BC Hydro's operating costs compare well against an appropriate peer group of U.S. utilities. This study is provided as Appendix T. • Section 5.7.2 shows the results of a comparison of our operating costs against those of other major electric utilities in Canada, which indicates that BC Hydro's operating costs compare well against major Canadian utilities. The data used for this review is provided as Appendix U. • Section 5.7.3 provides the results of recent independent benchmarking on maintenance delivery costs by Navigant and First Quartile, which demonstrates that BC Hydro's costs are consistent with or better than its utility peers. • Section 5.7.4 summarizes the benchmarks provided to support the operating costs and FTEs for various KBUs as discussed in Chapters 5A through 5G.

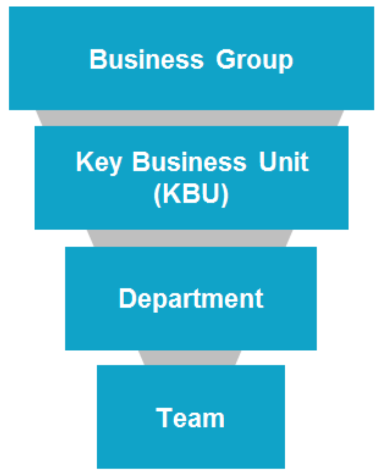
5.3 Overview of How BC Hydro is Organized

BC Hydro has six Business Groups, made up of 39 KBUs. We have completed our re-organization from an organization divided according to lines of business to a centralized organizational structure that aligns with the work functions that we perform – planning, building, operating and supporting.

5.3.1 Organizational Nomenclature

Figure 5-2 below provides a simplified diagram of our organizational structure, for the purpose of clarifying nomenclature used in this Application.

Figure 5-2 Organizational Nomenclature



5.3.2 The Move to a Centralized and Functionally Aligned Organization Is Complete

In October 2017, BC Hydro took the last step in moving to a centralized and functionally-aligned organizational structure. This final, incremental change completes the shift towards centralizing functions that BC Hydro has pursued over time. This functional alignment encourages consistent adoption of best practices used across the company and facilitates stronger collaboration and cooperation in similar functions across our business.

In recent years, BC Hydro had centralized its Finance, Safety and Supply Chain functions. The most significant part of the recently completed final step was to:

- Bring together the KBUs responsible for Power System planning into a Business Group called Integrated Planning; and
- Bring together the KBUs responsible for Power System operations into a Business Group called Operations.

This final step was not intended to drive specific cost reductions, but we believe that the intangible benefits of improved collaboration and consistent adoption of best practices can only assist the efficient management of the company. Our Safety

Business Group provides a good illustration of the benefits of functional alignment. Safety functions were previously distributed throughout the business and in its Decision on BC Hydro's Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, the BCUC encouraged BC Hydro to implement a comprehensive safety management program.[145] Since centralizing, we have been able to improve consistency of and clarity on safety requirements throughout the company. This promotes improved safety performance and a stronger safety culture.[146]

The centralized organizational structure aligns our Business Groups to the lifecycle of our work delivery. Our Business Groups are now organized under our four major work functions – Plan, Build, Operate, and Support. This is shown in Figure 5-3 below.

Figure 5-3 Plan-Build-Operate-Support Model

The change brings together groups with similar functions that were previously separated by our different lines of business - Generation, Transmission, and Distribution. In addition, KBUs within these Business Groups have aligned their work to our main asset types – station assets (generation plants and substations) and line assets (transmission and distribution lines).

Our Business Groups and their respective KBUs are summarized in Table 5-2 below. Table 5-2 is followed by a brief synopsis of our Plan, Build, Operate, and

145 British Columbia Utilities Commission Decision and Order No. G-16-09, BC Hydro Fiscal 2009 to Fiscal 2010 Revenue Requirements Application (March 13, 2009), page 49.

146 BC Hydro 2017/18 Annual Service Plan Report, pages 18 to 20, 'Goal 4: Safety Above All, Safety Performance Measures.

Support functions. Chapters 5A to 5G provide detailed information on the operating costs and FTEs for each Business Group and KBU.

Table 5-2 Business Groups and KBUs[147]

	Business Group	Key Business Unit
Plan	Integrated Planning	Energy Planning and Analytics
		Dam Safety
		Stations Asset Planning
		Line Asset Planning
		Interconnections and Shared Assets
		Engineering
Build	Capital Infrastructure Project Delivery	Project Delivery
		Indigenous Relations
		Environment
		Properties
Operate	Operations	Program and Contract Management
		Line Field Operations
		Stations Field Operations
		Distribution Design and Customer Connect
		Construction Services
		Generation System Operations
		Transmission and Distribution System Operations
Support	Safety	Safety System and Assurance
		Learning and Development
		Field Safety Services
		Security and Emergency Management
	Finance, Technology, Supply Chain	Finance
		Technology
		Supply Chain
	People, Customer, Corporate Affairs	Human Resources
		Customer Service
		Conservation and Energy Management
		Power Acquisitions and Contract Management
		Communications and Community Engagement
		Regulatory and Rates
		Ethics and Merit Office
	Other[148]	Office of the General Counsel[149]
		Office of the President and Chief Operating Officer

147 Each Business Group also includes a Business Unit Support KBU. These KBUs are relatively small and primarily include funding for BC Hydro's Executive Team members and their support staff.
148 The Other category was created to support the presentation of information and is not a Business Group.
149 The Office of the General Counsel reports directly to the President and Chief Operating Officer.

- **Plan (Integrated Planning Business Group):** The Integrated Planning Business Group is responsible for system planning. It brings together our asset planning functions which are performed by the Dam Safety, Stations Asset Planning, and Line Asset Planning KBUs. It also includes the Engineering KBU, the Interconnections and Shared Assets KBU, and Energy Planning and Analytics KBU. These KBUs work together to develop short and long-term maintenance and capital investment plans. The plans are then implemented by either the Capital Infrastructure Project Delivery Business Group or the Operations Business Group.
- **Build (Capital Infrastructure Project Delivery Business Group):** The Capital Infrastructure Project Delivery Business Group brings together the Project Delivery KBU with the other KBUs that are integral for the successful delivery of capital projects: the Indigenous Relations KBU, the Environment KBU and the Properties KBU. This Business Group is responsible for delivering our major capital projects on time and on budget while also balancing our environmental commitments, managing our land and properties, and developing and sustaining meaningful relationships with Indigenous communities.
- **Operate (Operations Business Group):** The Operations Business Group brings together the operations functions of our previous Transmission and Distribution Business Group and Generation Business Group. These functions have been re-aligned to our asset types, with the creation of the Stations Field Operations KBU (overseeing our generation and transmission station asset operations) and the Line Field Operations KBU (overseeing our distribution and transmission line operations). This Business Group also includes other operations-focused KBUs – the Transmission and Distribution System Operations KBU, the Generation System Operations KBU, the Program and Contract Management KBU, the Distribution Design and Customer Connections KBU, and the Construction Services KBU. These KBUs collaborate to implement work, maximize the value of the system, and connect our customers.

- **Support** – Three Business Groups provide services that support the planning, building and operation of BC Hydro's electricity system. Specifically:
  - **Safety Business Group** – This Business Group includes the Safety System and Assurance KBU, the Learning and Development KBU, the Field Safety Services KBU and the Security and Emergency Management KBU. It supports safety leadership across the organization. It is responsible for setting direction, training and oversight of our safety and security programs for our employees, contractors, and the public;
  - **Finance, Technology Supply Chain Business Group** – This Business Group includes the Finance KBU, the Technology KBU and the Supply Chain KBU. It is responsible for financial oversight and strategic business support for the company, the planning, design, delivery, operations, support and management of BC Hydro's information, operations and telecommunications technologies, and procuring and delivering materials, vehicles, and services; and
  - **People, Customer, Corporate Affairs Business Group** – This Business Group includes the Human Resources KBU, the Customer Service KBU, the Conservation and Energy Management KBU, the Power Acquisitions and Contract Management KBU, the Communications and Community Engagement KBU, the Regulatory and Rates KBU and the Ethics and Merit Office KBU. It supports and develops personnel, is responsible for customer service, and manages key relationships with stakeholders including governments and regulators.

5.4 BC Hydro has Used a Robust Budgeting Process

The forecast operating costs presented in this Application are the product of a robust budgeting process that involves top-down and bottom-up elements. The approach goes beyond a simple examination of incremental changes from the prior year. It requires Business Groups and individual KBUs to consider, and articulate to the Executive Team, their overall responsibilities, cost drivers, FTEs and targeted outcomes.

5.4.1 BC Hydro has Reviewed More than just Incremental Requirements

In its Decision on the Previous Application, the BCUC expressed that, in reviewing the incremental cost changes sought by BC Hydro in the Previous Application, it did not have a high degree of comfort in BC Hydro's starting point, being the 2016 base operating cost.

In this Application, we have made deliberate efforts to present the full cost picture rather than focusing only on incremental changes. The detailed cost and FTE information provided by Business Group and by KBU in Chapters 5A through 5G represents the culmination of the budgetary process undertaken throughout the organization.

5.4.2 Budgeting Approach Involves Bottom-Up and Top-Down Elements

BC Hydro's budgeting process includes both bottom-up and top-down elements.

From a bottom-up perspective, each KBU conducts an in-depth review of their operating costs, considering current operational and project related needs based on forecast work plans, resourcing requirements and legislative and compliance requirements. Through this process, cost pressures and savings opportunities are identified and consolidated at a Business Group level.

From a top-down perspective, BC Hydro's Executive Team reviews the identified cost pressures and savings opportunities and considers the Mandate Letter from the

Government of B.C. as well as the goals and targets in the Service Plan to inform an overall top-down target.

During the budgeting process for this Application, which occurred in conjunction with the Comprehensive Review, the Executive Team determined that, with the exception of certain uncontrollable costs and Standard Labour Rate increases, all cost pressures would be managed within the existing (i.e., fiscal 2019 forecast) operating cost budget. We identified savings throughout the organization in order to offset the cost pressures. This outcome is described further in section 5.5.2 below.

5.4.3 BC Hydro has a Vacancy Management Governance Process

BC Hydro has an established governance process to manage vacancies, which assists in managing within budget targets. The governance process has two main elements.

First, filling vacancies requires the prior review and approval by an Executive Team member or Director of a KBU. Each Executive Team member or KBU Director reviews and approves requests, which detail the reason for the vacancy as well as the job title, job level, affiliation and employment status of each position.

Second, any request to create a new position that is not within BC Hydro's established FTE and budget plans must be supported by a business case and be accommodated with offsetting cost reductions or incremental cost savings.

5.4.4 Appropriate Budget Oversight and Reporting Is in Place

BC Hydro has appropriate financial oversight processes in place so that operating cost budgets determined through the budgeting process described above are maintained.

The Finance KBU provides ongoing oversight through financial and management reporting throughout the year. Managers receive monthly reporting outlining their monthly and year-to-date results so that KBUs are tracking and comparing actual spending to budgeted amounts. On a monthly basis, each Executive Team member reviews these results along with a dashboard of performance metrics for their Business Group with their direct reports. In addition, the Executive Team reviews the consolidated financial results each month.

The Finance KBU also identifies, quantifies, and explains any variances to the management teams of each KBU and to the Executive Team. Year-end forecasts are prepared and updated monthly to identify any expected challenges in meeting annual targets. Emerging cost pressures are identified, and if necessary, corrective actions are implemented so that BC Hydro remains on track to achieve its targets.

5.4.5 The Work Smart Program has Created Capacity to Manage Workload and Absorb New Work

Work Smart is BC Hydro's program for continuous process improvement and is based upon Lean principles. Lean is a business philosophy focusing on streamlining work as well as identifying and eliminating non-value-added activities.

5.4.5.1 The Benefits of the Work Smart Program Have Exceeded Expectations

As of the end of fiscal 2018, BC Hydro has realized an estimated 80,000 annual capacity hours gained as a result of Work Smart program initiatives. The estimated realized hours gained exceed the forecast amount of 46,550 hours provided by BC Hydro in the Previous Application.[150] Capacity hours gained is the difference between the work effort of the process before the Work Smart initiative is undertaken and after the implementation of the Work Smart recommendations.

An example of a successful Work Smart initiative is the Project Scaling initiative.

In 2016, BC Hydro’s project delivery method was independently assessed using the global standard, Organizational Project Management Maturity Model, and was rated 91 per cent, which is considered world-class. However, for smaller and lower risk

[150] Refer to BC Hydro’s Response to BCUC IR 2.213.04 in the Previous Application proceeding.

projects, such as projects with low design complexity and limited stakeholder impact, BC Hydro identified an opportunity to scale down the project delivery activities to reduce time and gain capacity. BC Hydro undertook a Work Smart review of the process and developed three accelerated scaling models, which are now being deployed in the organization. These models enable the project team to combine stages and deliverables into a single set, reducing the number of design reports, project estimates, and wait time between stages.

Approximately 12 projects are currently piloting one of the accelerated scaling models. A successful example is the Mica Townsite Schoolhouse and Staff House Improvement project, which gained approximately 1,100 hours in capacity and reduced its schedule by six months by using an Accelerated Scaling model.

5.4.5.2 Using Work Smart Gains to Address Workload and Absorb New Work is Valuable and Consistent with Practices at Other Companies

In its Decision, the BCUC expressed its belief that the efficiency savings generated by BC Hydro's Work Smart program should result in incremental cost savings.[151] We believe that our approach of using these gains to address workload issues and absorb new work, so that new costs can be avoided, is beneficial. Efficiency gains through the Work Smart program are an important part of our efforts to keep operating cost increases below the rate of inflation.

Work Smart relies on front-line employees to identify opportunities to make processes more efficient and effective as well as to save time and resources. We believe that using the gains from these opportunities to address workload issues and allow employees to focus on higher value work is the most effective way to encourage employees to bring forward ideas and participate in the Work Smart process.

[151] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 34.

BC Hydro's approach of using Work Smart gains to address workload issues is also consistent with practices at other companies. For example:

- Washington State operates a successful Lean program known as "Results Washington", which is consistent with BC Hydro's Work Smart program. Its January 2018 Annual Progress Report indicates that its initiatives focus on avoided costs rather than cost savings;[152] and
- The Insurance Corporation of British Columbia operates a successful Lean program known as Operational Excellence. Its 2017 Revenue Requirements Application indicates that cost savings are not an objective of this program.[153]

5.5 Fiscal 2020 to Fiscal 2021 Operating Costs Increases have been Held Below Forecast Inflation

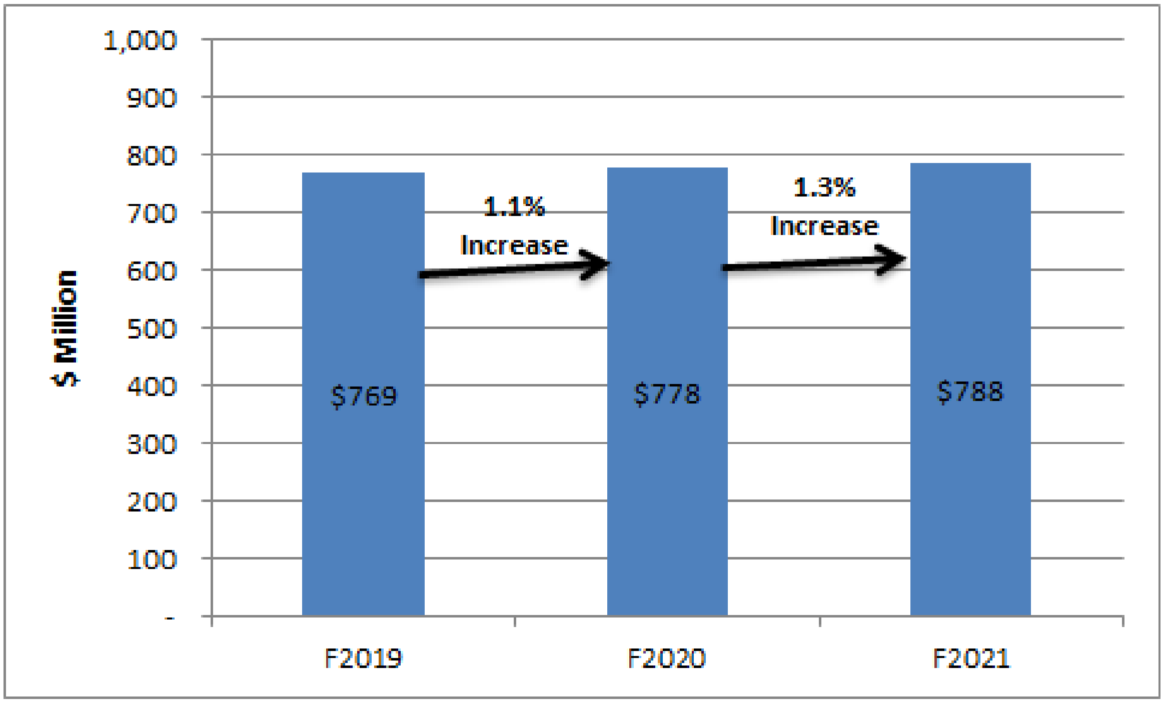
This section summarizes the fiscal 2020 to fiscal 2021 forecast operating costs. BC Hydro expects to be able to limit base operating cost increases to below the forecast rate of inflation[154] over the test period. Base operating costs are forecast to increase by 1.1 per cent in fiscal 2020 and 1.3 per cent in fiscal 2021 for an average increase of 1.2 per cent per year. This is shown in Figure 5-4 below.

[152] Results Washington Report: https://www.results.wa.gov/sites/default/files/2018%20Results%20WA%20report%20final.pdf

[153] ICBC 2017 Revenue Requirements Application, 6-2 https://www.bcuc.com/Documents/Proceedings/2017/DOC_49993_B-1_ICBC-2017-Revenue-Requirements-Application.pdf

[154] BC Hydro uses the B.C. Consumer Price Index measure for the forecast rate of inflation. The forecast rate of inflation for fiscal 2019, fiscal 2020 and fiscal 2021 is 2.7 per cent, 2.3 per cent and 2.0 per cent, respectively.

Figure 5-4 Base Operating Costs Increases Are Below Inflation



5.5.1 Base Operating Costs Should be the Focus when Assessing BC Hydro's Cost Management

We use various terminologies when describing BC Hydro's operating costs. Table 5-3 below helps to explain the various operating cost views. Base operating costs are, in BC Hydro's view, the relevant measure for the assessment of our efforts to control operating costs because they exclude costs that, among other things,[155] vary according to changes in accounting rules and the mechanisms in place to recover regulatory account balances. BC Hydro reports its base operating costs as part of its Annual Service Plan.

[155] Base operating cost also exclude operating costs related to the BC Hydro's purchase of Teck's two-thirds interest in Waneta and the Customer Crisis Fund. These costs are excluded because they are offset by revenues, resulting in a net zero impact.

Table 5-3 Explanation of Operating Cost Views

Cost Components	Base Operating Costs	Net Operating Costs	Gross Operating Costs	Current Operating Costs
Normal day to day operations of BC Hydro including costs such as Labour, Materials and Services.	√	√	√	√
Recoveries Capitalized Costs Re-Classification Adjustment	√	√	√	√
IPP Capital Leases Capital overhead that can no longer be capitalized under IFRS Costs related to BC Hydro's purchase of Teck's two-thirds interest in Waneta[156] Customer Crisis Fund		√	√	√
Costs incurred in the current period but recovered in rates in future years consistent with the recovery mechanisms established for each regulatory account.			√	
Costs incurred in prior periods to be recovered in the current period consistent with the recovery mechanisms established for each regulatory account.				√

5.5.2 Controllable Cost Reductions Are Offsetting Increases in Non-Controllable Costs

BC Hydro has been able to limit base operating cost increases to below the forecast rate of inflation for the test period by offsetting increases to non-controllable costs with reductions to controllable costs.

5.5.2.1 Overview of the Change in Base Operating Costs

Table 5-4 below provides a continuity table that summarizes the changes to BC Hydro's base operating costs.

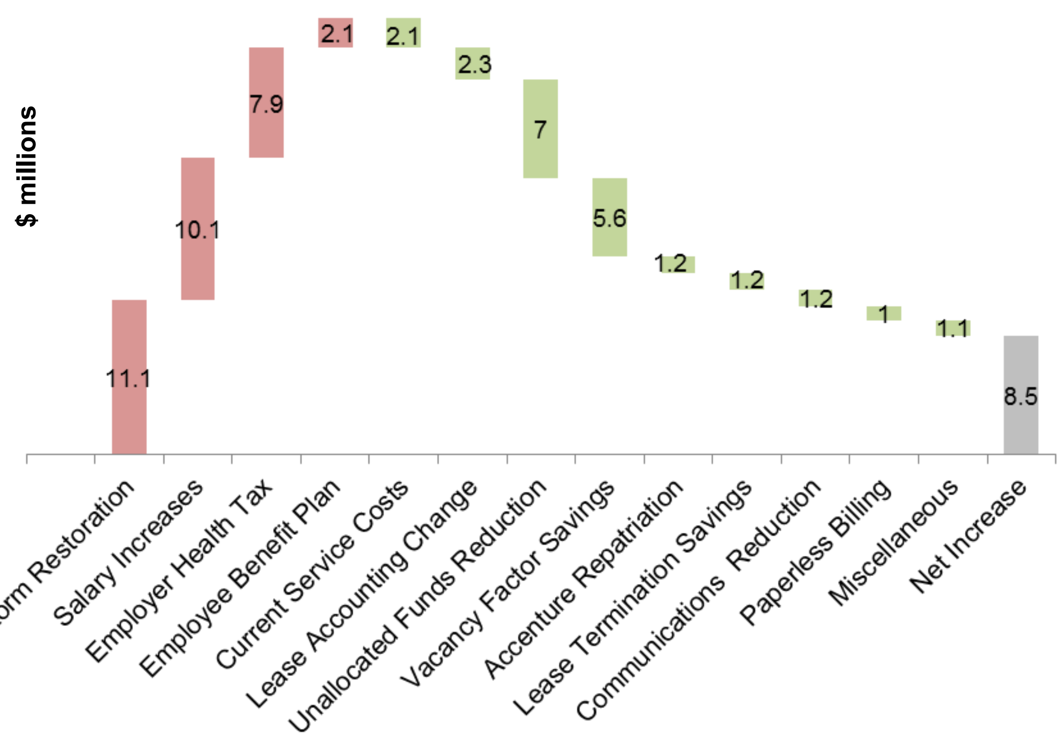
[156] Further information on BC Hydro's purchase of Teck's two-thirds interest in Waneta is provided in Chapter 4, section 4.2.3.

Table 5-4 Summary of Changes to BC Hydro's Base Operating Costs

	($ million)		F2020 Plan	F2021 Plan
1	F2019 Revenue Requirement Application Plan		961.1	
2	Compliance Filing Adjustment (Schedule 5.0, line 8)		10.4	
3	F2019 Revenue Requirement Application Compliance Filing Plan (Schedule 5.0, line 15)		971.5	
4	F2019 Forecast Operating Cost Increases:			
5	Waneta 2/3rd Operating Costs (Schedule 5.0, line 12)		3.8	
6	Customer Crisis Fund Operating Costs (Schedule 5.0, line 13)		4.0	
7	F2019 Forecast Operating Cost (Schedule 5.0, line 15)		979.3	
8	Less:			
9	IFRS Ineligible Capital Overhead (Schedule 5.0, line 10)		(147.7)	
10	Independent Power Producer Capital Leases (Schedule 5.0, line 11)		(54.3)	
11	Waneta 2/3rd Operating Costs (Schedule 5.0, line 12)		(3.8)	
12	Customer Crisis Fund Operating Costs (Schedule 5.0, line 13)		(4.0)	
13	Base Operating Costs (Carry Forward) (Schedule 5.0, line 9)	A	769.5	777.9
14	Test Period Savings	B	(13.6)	(0.4)
15	Test Period Cost Increases			
16	Labour		11.0	10.3
17	Storm restoration		11.1	
18	Total Test Period Cost Increases	C	22.1	10.3
19	Test Period Net Increase/(Decrease)	D=B+C	8.5	9.9
20	Base Operating Costs (Current Year) (Schedule 5.0, line 9)	E=A+D	777.9	787.8
21	Total Percentage increase	(E-A)/A	1.1%	1.3%

Figure 5-5 below provides a visual breakdown of cost increases and savings for fiscal 2020. The first four red bars show the factors that are increasing costs. The green bars show offsetting savings, culminating in the net change of $8.5 million (the grey bar).

Figure 5-5 Summary of Changes to BC Hydro's Base Operating Costs (Fiscal 2020)



5.5.2.2 The Forecast Base Operating Cost Increase is Primarily Driven by Non-Controllable Factors

As depicted in the figure above, three factors are driving most of BC Hydro's forecast base operating cost increases. Two of these factors – storm restoration and the employer health tax – are non-discretionary and are beyond BC Hydro's control. The third – Standard Labour Rate increases – is tied to the bargaining mandate for union staff provided to BC Hydro by the Public Sector Employers Council. BC Hydro considers management and professional compensation increases, which are essentially cost of living increases, to be a priority akin to non-controllable costs given how BC Hydro's employee compensation compares to median market. BC Hydro has had limited ability to increase management and professional salaries since 2012, due to the Public Sector Employers Council prior salary freeze policy.

Table 5-5 below provides a more detailed breakdown of Test Period Cost Increases.

Table 5-5 Test Period Cost Increases

Item	Description	Fiscal 2020 Incremental ($ million)	Fiscal 2021 Incremental ($ million)
Storm Restoration	BC Hydro continues to budget for storm restoration costs using a five-year average of normal weather years. In recent years, we have experienced higher levels of storm related damage, which has caused the five-year average of storm restoration costs to increase. Variances between planned and actual storm restoration costs are deferred to the Storm Restoration Costs Regulatory Account, which is discussed in Chapter 7, section 7.8.1.	11.1	0
Labour Costs			
Salary Increases	The Public Sector Employers Council provides all provincial public sector employers a common bargaining mandate for negotiating union collective agreements. It specifies the term of the agreement and general wage increases that employers can provide. The collective agreements at BC Hydro expire March 31, 2019 and the Public Sector Employers Council bargaining mandate specifies a three-year term (fiscal 2020 to fiscal 2022) with a 2.0 per cent general wage increase each year. The cost increase for this test period includes a 2.0 per cent general wage increase for union employees and a 2.5 per cent general wage increase for Management and Professional employees. Since 2012, due to the Public Sector Employers Council salary freeze policy, salary increases for Management and Professional employees have been limited and below the amount provided to unionized employees over the same period.	10.1	8.9
Employer Health Tax	The Government of B.C.'s Budget, released in February 2018, announced the implementation of the Employer Health Tax. Cost increases related to the Employer Health Tax are partially offset by the elimination of Medical Service Plan premiums.	7.9	(1.9)

Item	Description	Fiscal 2020 Incremental ($ million)	Fiscal 2021 Incremental ($ million)
Employee Benefit Plan	The forecast increase in employee benefits is primarily due to defined rates and inflationary increases which are largely uncontrolable. Benefit costs include the employer portion of Canada Pension Plan, employment Insurance, health and dental premiums, long term disability and workers' compensation premiums.	2.1	2.0
Current Service Costs	The resulting savings in fiscal 2020 are primarily due to the elimination of Medical Service Plan premiums. In fiscal 2021, the current service costs increase due to forecast salary increases which have a corresponding impact on current service costs. Please refer to Chapter 5G, section 5G.9.1 for more information on current service costs.	(2.1)	1.3
Unallocated Funds Reduction	The 2013 10 Year Rates Plan prescribed certain operating cost and rate increase targets. To manage unanticipated cost pressures within these targets, BC Hydro maintained a budget of unallocated funds. Going forward, this budget is being repurposed, in part, to offset the labour cost increases listed above, resulting in net labour cost increase of $11.0 million in fiscal 2020. For further information, please see Chapter 5G, section 5G.7.2	(7.0)	0
Labour Costs Sub-Total		**11.0**	**10.3**
Total		**22.1**	**10.3**

5.5.2.3 Cost Savings Have Been Identified Across the Organization to Offset the Cost Pressures

Table 5-6 below provides a more detailed breakdown of Test Period Savings that have been identified across the organization to offset the cost pressures identified in section 5.5.2.2 above.

1 **Table 5-6 Test Period Savings**

Item	Description	Fiscal 2020 Incremental ($ million)	Fiscal 2021 Incremental ($ million)
Vacancy Factor Savings	In previous years, some KBUs have reduced their labour budgets to recognize that positions will not remain filled 100 per cent of the time. The exact approach for identifying these reductions for each KBU has varied. In the test period, BC Hydro has taken a consistent approach to assessing each KBU and identifying any budget reductions associated with unfilled positions. Across all KBUs, labour budgets have been reduced by an additional $5.6 million in total.	(5.6)	0
Lease Accounting Change	As identified in Chapter 8, section 8.13.3, a new accounting standard on leases, International Financial Reporting Standards (**IFRS**) 16, is effective for fiscal 2020. IFRS 16 eliminates the classification of leases as either operating or capital for lessees and, instead, introduces a single lessee accounting model. The new standard will impact Energy Purchase Agreements, property lease/rental agreements, vehicle leases, and other agreements. This impact will result in a reduction in operating costs with corresponding increases in finance charges and amortization costs.	(2.3)	0
Accenture Repatriation	As discussed in section 5.6.2, BC Hydro's decision to repatriate services previously provided by Accenture has resulted in an annual cost savings of $8.2 million. $7.0 million in annual savings were achieved prior to the test period and the remaining $1.2 million in annual savings will be achieved in fiscal 2020.	(1.2)	0
Lease Termination Savings	BC Hydro consolidated its lease at Central Park Place, eliminating three floors of office space.	(1.2)	0
Communications Reduction	The advertising budget in the Communications and Community Engagement KBU has been reduced.	(1.2)	0
Paperless Billing and Customer Correspondence	BC Hydro has continued to reduce postage and printing costs by increasing the number of paperless bills and other forms of correspondence.	(1.0)	0
Miscellaneous		(1.1)	(0.4)
Total		**(13.6)**	**(0.4)**

Base operating costs are a component of net operating costs. Net operating costs also include capital overhead that can no longer be capitalized under IFRS, costs related to the 2017 Waneta Transaction and the Customer Crisis Fund.

- Net operating costs, combined with costs incurred in the current period that are to be recovered in rates in future years through the recovery mechanisms established for each regulatory account, represent BC Hydro's total gross operating costs.
- Net operating costs, combined with costs incurred in prior periods to be recovered in the current period through the recovery mechanisms established for each regulatory account, represent BC Hydro's total current operating costs.

Table 5-7 below provides a continuity table that summarizes the changes to BC Hydro's net operating costs.

Table 5-7 Summary of BC Hydro's Operating Costs[157]

	($ million)		F2020 Plan	F2021 Plan
1	F2019 Revenue Requirement Application Plan		961.1	
2	Compliance Filing Adjustment (Schedule 5.0, line 8)		10.4	
3	F2019 Revenue Requirement Application Compliance Filing Plan (Schedule 5.0, line 15)	A	971.5	
4	Reorganization Impact	B	-	
5	Budget Transfers Between Business Groups	C	-	
6	Waneta 2/3rd Operating Costs (Schedule 5.0, line 12)	D	3.8	
7	Customer Crisis Fund Operating Costs (Schedule 5.0, line 13)	E	4.0	
8	F2019 Revenue Requirement Application Forecast / carry forward plan (Schedule 5.0, line 15)	F=Σ A to E	979.3	959.0
9	Current Year Incremental Adjustments:			
10	Independent Power Producer Capital Leases		(54.3)	-
11	IFRS Ineligible Capital Overhead		22.4	22.4
12	Waneta 2/3rd Operating Costs		1.9	0.2
13	Customer Crisis Fund Operating Costs		1.3	-
14		G	(28.8)	22.6
15	Current Year Budget Transfers Between Business Groups	H	-	-
16	Test Period Savings	I	(13.6)	(0.4)
17	Test Period Cost Increases			
18	Labour		11.0	10.3
19	Storm Restoration		11.1	
20	Total Test Period Cost Increases	J	22.1	10.3
21	Test Period Net Increase/(Decrease)	K=I+J	8.5	9.9
22	Net Operating Costs (Schedule 5.0, line 15)	G+H+K	959.0	991.4

Table 5-8 below shows the reconciliation of base operating costs to the net operating costs as shown in the financial schedules in Appendix A.

[157] Row 2 relates to the current pension cost adjustment corresponding with BCUC Order No. G-47-18, Directive 18, which directed BC Hydro to use the discount rate in effect at the time the forecast, was prepared to calculate current service costs;

Rows 4, 5 and 15 of relate to restructuring impacts and budget transfers between Business Groups. These rows have a zero balance because on a consolidated basis, by themselves, they net to zero. The continuity schedules for each Business Group are shown later in this chapter. These schedules show the specific restructuring impacts and budget transfers for each Business Group.

Rows 6 and 12 are costs related to BC Hydro's purchase of Teck's two-third interest in Waneta, per BCUC Order No. G-130-18

Rows 7 and 13 are costs related to the Customer Crisis Fund, approved by BCUC Order No. G-166-17;

Row 10 relates to the impact of the new accounting standard on leases, IFRS 16 which is further explained in Chapter 5G, section 5G.6 Independent Power Producers Capital Leases;

Row 11 represents IFRS ineligible capital overhead costs that are being phased in to operating costs over a ten-year period. Please refer to Chapter 5G, section 5G.8 for further information on IFRS ineligible capital overhead.

Table 5-8 Reconciliation of Base Operating Costs to Net Operating Costs

	($ million)	F2020 Plan	F2021 Plan
1	Base Operating Cost	777.9	787.8
2	IFRS Ineligible Capital Overhead (Schedule 5.0, line 10)	170.1	192.5
3	Independent Power Producer Capital Leases (Schedule 5.0, line 11)	-	-
4	Waneta 2/3rd Operating Costs (Schedule 5.0, line 12)	5.7	5.9
5	Customer Crisis Fund Operating Costs (Schedule 5.0, line 13)	5.3	5.3
6	**Net Operating Costs (Schedule 5.0, line 15)**	**959.0**	**991.4**

5.6 FTE Increases are Driven by Capital Investment and have Reduced BC Hydro's Overall Costs

This section reviews BC Hydro's FTEs[158] in previous fiscal years and during the test period. It also discusses BC Hydro's Standard Labour Rates. In this section, we make the following points:

- By replacing contractors with internal FTEs, the Workforce Optimization Program has increased the number of FTEs while decreasing BC Hydro's total costs by an estimated $18.5 million annually.
- The repatriation of services previously provided by Accenture has also increased BC Hydro's FTEs while generating $8.2 million in annual savings, exceeding BC Hydro's original expectations.
- Apart from growth in the workforce directly related to increased capital investment, BC Hydro's FTEs have remained relatively flat since fiscal 2012 and are forecast to remain flat over the test period.[159]

[158] FTEs are calculated by taking the total number of hours (regular and overtime) worked in a given year, divided by the average number of hours a full time employee would work per year. These averages differ by affiliation. For the fiscal 2020 to fiscal 2021 test period, these averages are 1,621 hours for Management and Professional employees (including Executive), 1,535 hours for MoveUp employees and 1,461 hours for International Brotherhood of Electrical Workers employees.

[159] FTEs are increasing by from 7,405 (fiscal 2019 forecast) to 7,477 (fiscal 2020 plan), for a net increase of 72 FTEs. The Site C Project is increasing by 71 FTEs from fiscal 2019 forecast to fiscal 2020 plan. Labour costs associated with FTEs working on the Site C Project are capitalized to the project, which means that they do not affect the test period revenue requirements. If FTE increases for the Site C Project are factored out, the overall increase in FTEs from fiscal 2019 forecast to fiscal 2020 plan is just one FTE.

- Over the test period, Standard Labour Rates are expected to increase due to BC Hydro's bargaining mandate, increases to employee benefits, and the employer health tax. A 2017 assessment by Morneau Shepell concluded that on a total cash basis, BC Hydro's employee compensation is 11 per cent below median market rates. After factoring in the value of pension benefits and time off programs, employee compensation is comparable to median market rates.

5.6.1 Replacing Contractors with Internal FTEs Has Decreased Total Costs

The Workforce Optimization Program, which was created in fiscal 2016, has decreased BC Hydro's total costs by an estimated $18.5 million annually. Table 5-9 below provides a summary of annual net (i.e., operating, capital and deferred) savings from the Workforce Optimization Program for fiscal 2020, by Business Group.

Table 5-9 Workforce Optimization Program Annual Net Savings (Fiscal 2020)

Business Group	Costs ($ millions)	Savings ($ millions)	Net Savings ($ millions)
Integrated Planning	9.7	12.7	3.0
Capital Infrastructure Project Delivery	31.2	34.3	3.0
Operations	16.9	24.7	7.9
Safety	4.0	5.3	1.3
Finance, Technology, Supply Chain	24.4	26.6	2.2
People, Customer, Corporate Affairs	6.1	6.4	0.3
Other	1.2	1.9	0.8
Total	**93.5**	**112.0**	**18.5**

The Workforce Optimization Program supports decisions on how work should be allocated and ensures those decisions are cost-effective. It primarily allows BC Hydro's KBUs to replace external contractors with internal FTEs when it is beneficial to do so. As discussed in section 5.6.1.2 below, we apply specific principles when making work allocation decisions and these decisions require a workforce adjustment request document that provides both quantitative and qualitative support for converting a contractor to an employee.

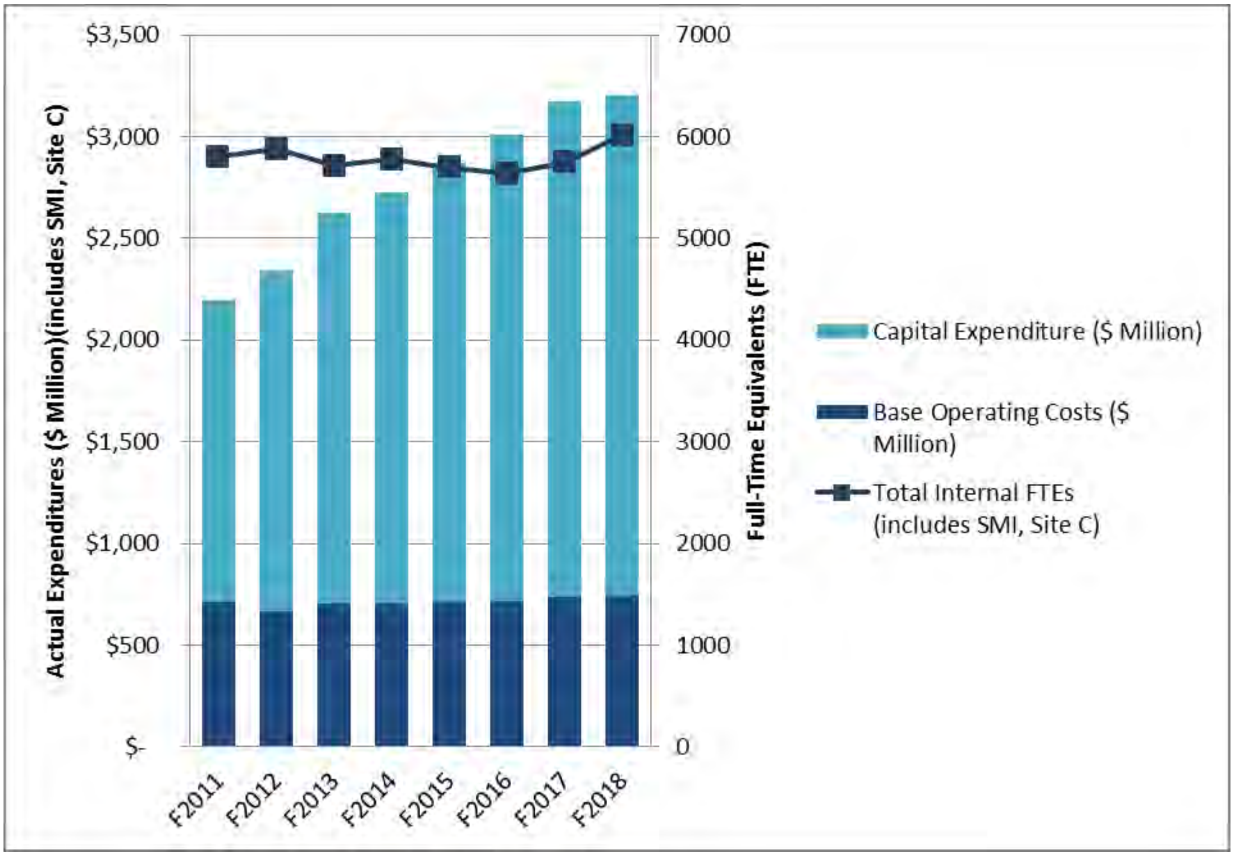
5.6.1.1 Focusing on Total Labour Costs, Rather than Number of FTEs, is Beneficial for Customers

The Workforce Optimization Program was developed in response to changing business requirements that, in many instances, made it more cost-effective to hire FTEs on a long-term basis rather than continuing to use contractors.

The 2011 Government Review had recommended that BC Hydro reduce the number of FTEs. Acting upon that recommendation, BC Hydro reduced its employee population and eliminated unfilled positions. From fiscal 2012 to fiscal 2016, BC Hydro managed to a FTE maximum, as directed by the Government of B.C., as part of an effort to provide affordable rates for customers.

However, BC Hydro’s labour requirements also increased significantly during these years, due to an increase in capital expenditures. As a result of the FTE maximum, BC Hydro’s FTEs did not keep pace with labour requirements. BC Hydro’s annual capital expenditures increased by 66 per cent from $1.48 billion in fiscal 2011 to $2.47 billion in fiscal 2018. Over the same period, BC Hydro’s FTEs increased by 4 per cent. This is shown in Figure 5-6 below.

Figure 5-6 Capital Expenditures and FTEs (Fiscal 2011 to Fiscal 2018)



In order to resource growing work volumes against a flat employee base, BC Hydro increased the contracting out of work that employees had insufficient capacity to perform.

While external suppliers are generally more expensive on a per-hour basis compared to employees, hiring internal employees represents an ongoing commitment and additional costs such as pension, benefits, facilities and training are considered. BC Hydro's fiscal 2013 to fiscal 2022 Capital Plan expected capital expenditures to peak in fiscal 2017 and return to fiscal 2013 levels by fiscal 2022. Since the work volume was not expected to be long-term, it was appropriate to hire contractors to resource this peak and avoid the ongoing costs associated with internal employees.

The annual capital planning process updates and prioritizes capital investments to respond to the latest information on system risks and needs. As capital plans were updated[160], the expected fiscal 2017 peak was replaced with more sustained levels of investment over time. BC Hydro's current fiscal 2020 to fiscal 2024 Capital Plan shows sustained volumes of work that will require both internal FTEs and external contractors.

In fiscal 2016, BC Hydro raised concerns with the Government of B.C., with regards to the costs of resourcing a sustained increase in capital plan work volumes with external contractors. In response, the Government of B.C. authorized BC Hydro to remove its internal FTE restrictions and transition to a "total cost" labour model. This shift was primarily intended to provide BC Hydro with the flexibility to replace external contractors with internal FTEs to improve quality, safety and reliability outcomes and reduce costs.

5.6.1.2 Decisions to Insource Are Based on Consistent Principles

The Workforce Optimization Program is BC Hydro's approach to optimizing the mix of internal labour and external contractors. BC Hydro uses a principles-based approach when deciding on whether to use employees or contractors that considers the ongoing nature of work, availability and skills of workers, and the total cost of employment.

The decision to perform work internally by employees or externally by contractors is guided by BC Hydro's Resource Allocation Principles, which are shown in Figure 5-7 below.

160 BC Hydro reviews and updates its Capital Plan on an annual basis to reflect changes in energy demand, asset risk, customer requirements, and other factors.

Figure 5-7 Resource Allocation Principles

	Work Characteristics	Workforce Characteristics
Completed Primarily Internally	• Base work • Frequent and complex • High business risk	• High internal capacity and capability • High internal efficiency
Completed Primarily Externally	• Peak work • Infrequent and time-limited • Niche expertise	• High external capacity and capability • High external efficiency

The following examples illustrate how these principles are applied to decisions made through the Workforce Optimization Program:

- BC Hydro has adopted a new Technology Delivery Model, which brings critical cybersecurity monitoring and response capability in-house. Contractors performing these functions were replaced with internal employees. The impact of these changes was cost neutral and aligns with the principle that work involving high business risks should be completed internally. Further information is provided in Chapter 5E, section 5E.5.1.
- BC Hydro employs a team of in-house lawyers with expertise in a range of subjects, since in-house lawyers are less costly than external lawyers. Through the Workforce Optimization Program, BC Hydro has replaced external legal counsel with internal lawyers, where feasible. BC Hydro continues to retain external counsel for specialized legal expertise, large regulatory filings, litigation, and to provide support for large transactions and projects. Further information is provided in Chapter 5G, section 5G.3.2.

5.6.1.3 The Decision to Hire FTEs to Replace Contractors Considers Long-Term Effects and Costs

Decisions to replace external contractors with internal FTEs, through the Workforce Optimization Program, must be supported by a workforce adjustment request document. These documents are reviewed by the requesting KBU, as well as the Finance KBU, Properties KBU, Human Resources KBU and the Executive Team

Member of the requesting Business Group. The documents provide both quantitative and qualitative support for converting a contractor to an employee.[161]

In its Decision, the BCUC expressed concern that there did not appear to be an assessment of the long-term effects and costs of hiring contractors as employees.[162] The documentation required by the Workforce Optimization Program accounts for both the short-term and long-term effects and costs of hiring contractors as employees. Specifically, workforce adjustment request documents consider:

- The costs of hiring internal employees against the costs of contracting out work to an external supplier. The costs of internal employees, measured by using Standard Labour Rates, includes base salary and wages, premiums, overtime, vacation/flex time, pension, employer-paid premiums, insurance, supplemental benefits and training.
- Other implications of employing internal resources such floor space requirements.
- Non-financial benefits such as maintaining knowledge about assets or programs in-house and establishing strong succession plans for potential retirements.

In addition, BC Hydro uses resource forecasts to determine our long-term labour needs. This includes assessing our current internal resources and external suppliers' abilities to meet the needs of our capital and maintenance plans. These long-term forecasts allow BC Hydro to:

- Plan for apprenticeship and trainee intakes;

[161] FTE additions through the Workforce Optimization Program Plan must be fully funded through an equivalent cost reduction. In most cases, this means a reduction in funding for external contractors; however, in some cases, FTE additions may be funded through reductions to other expenditures (e.g., materials, building and equipment, etc.), or by re-purposing other vacant positions.

[162] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 34.

- Model the potential impacts of changes in attrition; andf
- Identify potential resource-related risks to our work plans (where demand may not match supply) and provide enough time to develop strategies to mitigate these risks.

5.6.1.4 Workforce Optimization Program Has Increased Total FTEs

The savings generated by the Workforce Optimization Program have caused BC Hydro's total FTEs to increase.

In our Previous Application, filed in July 2016, we identified 170 additional FTEs as a result of the Workforce Optimization Program and noted that additional Workforce Optimization Program positions would continue to be implemented in cases where cost savings and/or improved outcomes could be achieved.[163]

The 170 additional FTEs forecast in our Previous Application were based on confirmed conversions of contractors to internal FTEs, at the time that the forecasts for that application were finalized. Since that time, the total number of FTEs added as a result of the Workforce Optimization Program has increased by approximately 535 to a total of approximately 706 FTEs, as additional conversions were confirmed for the fiscal 2017 to fiscal 2019 period as well as the upcoming fiscal 2020 to fiscal 2021 period.

Table 5-10 below provides further details on the additional 535 FTEs confirmed since the Previous Application, by KBU.

[163] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Chapter 5, section 5.3.1.3.

Table 5-10 Workforce Optimization FTEs by KBU (Fiscal 2019 RRA Plan to Fiscal 2020 RRA Plan)

KBU	FTE Increase	Primary Drivers
Project Delivery	94.0	• Improved workforce continuity. • Strengthened contract management, governance and oversight procedures. • Addressed union grievances. • Reduced costs. • Reduced contract administration. These conversions were primarily related to the Capital Construction and Project Services departments.
Technology	59.5	• Moved critical functions in-house. • Reduced risk of losing institutional knowledge. • Reduced the number of management roles being performed by contractors. Areas where contractors were replaced with internal FTEs included service governance, vendor integration management, cybersecurity, application services and project management.
Line Field Operations	59.0	• Reduced costs. 44 FTEs were field trade positions and 15 FTEs were administrative positions, primarily assigned to the Operations Support Processing Center team.
Engineering	56.0	• Reduced costs. • Maintained a sufficient level of internal knowledge within BC Hydro. These FTEs were added throughout the KBU.
Supply Chain	40.0	• Reduced risk of losing institutional knowledge. • Reduced turnover to enable consistent and efficient work. 28 FTEs were added to the Procurement Department and primarily included procurement analysts and category management professionals as well as an administrative/clerical pool, as described in Chapter 5E, section 5E.5.3. Eight FTEs were added in Fleet Services, mainly for mechanics in the field and four FTEs were added in Materials Management, primarily for material demand planners.

KBU	FTE Increase	Primary Drivers
Distribution Design and Customer Connections	35.0	• Reduced design work costs. • Increased internal capacity to meet the unprecedented volume of customer connections, as discussed further in Chapter 5C, section 5C.7.2. The positions added were all frontline staff and consisted of 28 Designers and seven Electric Service Coordinators.
Indigenous Relations	21.6	• Ownership of our relationships with First Nations leading to improved relationships and increased internal knowledge of individual First Nation community interests, perspectives and objectives.
T&D System Operations	21.0	• Conversion of three contractors to internal FTEs to perform NERC CIPv5 roles. These roles are required to sustain mandatory compliance with NERC CIPv5 standards. Further information is provided in Chapter 5C, section 5C.10.3. • Thirteen FTEs reflect the BCUC's anticipated appointment of BC Hydro as the Reliability Coordinator for B.C. This role was previously contracted out to Peak Reliability, which has notified BC Hydro and other entities that it will no longer provide this service. Further information is provided in Chapter 5C, section 5C.10.1.7. • The remaining five FTEs represent conversions undertaken to reduce labour costs.
Communications and Community Engagement	18.0	• Reduced costs. • Increased consistency and oversight. These conversions were primarily related to BC Hydro's Community Outreach team.
Finance	14.6	• Reduced costs • Increased internal knowledge These conversions were primarily related to the Change Management team. Replacing external change management contractors with internal FTEs enables a consistent approach, understanding of important organizational context and knowledge retention.
Customer Service	14.1	• Seven FTEs are associated with the delivery of the Customer Crisis Fund Pilot. These costs are offset by the Customer Crisis Fund Rate Rider. Further information is provided in Chapter 5F, section 5F.5.1.1. • The primary drivers for the remaining conversions were reduced costs and reduced turnover.

KBU	FTE Increase	Primary Drivers
Construction Services	14.0	• Reduced costs. These conversions were primarily related to project support staff.
Stations Field Operations	13.0	• Reduced costs. These conversions were primarily related to positions created for newly-graduated Communications Protection and Control Technologists.
Other KBUs	75.8	The remaining 75.8 FTEs are spread across 16 KBUs, averaging approximately five conversions per KBU.
Total	**535.6**	

5.6.2 The Recent Accenture Repatriation is Expected to Deliver Benefits

In May 2018, BC Hydro successfully transitioned important services previously performed by Accenture back into BC Hydro. The repatriation of work from Accenture, along with hiring many employees previously working for Accenture, is expected to deliver benefits to customers including approximately $8.2 million in annual savings as well as more flexible customer service.

5.6.2.1 Accenture Repatriation Restores Direct Control Over Key Support and Customer-facing Functions

The Accenture repatriation restores direct control over key support and customer-facing functions.

In fiscal 2003, BC Hydro outsourced certain work to Accenture, including services in Customer Service, Human Resources, Finance, Purchasing, Office Services and Information Technology. Over the years, adjustments were made to the services provided. In fiscal 2011, BC Hydro's contract with Accenture was restructured, with the following services included:

- Customer Service (Mass Market and Transmission Billing, Credit and Collection, Payment Processing, Contact Centre);
- Finance (Accounts Payable);

- Human Resources (Employee Service Centre, payroll, recruiting services, Tempworks, benefits administration); and
- Office Services (graphic design, mailroom, switchboard, records management).

Between fiscal 2003 and fiscal 2018, BC Hydro and Accenture maintained a strong working relationship and achieved many successes that benefitted BC Hydro's customers and our operations.

The agreement with Accenture was due to expire on April 30, 2018. We considered three options:

- Go to market via public procurement process;
- Renew the agreement with Accenture for another three years to 2021; or
- Repatriate the services back to BC Hydro.

BC Hydro's research indicated there was a limited market for the full scope of our outsourced services. While the relationship with Accenture was strong, there were a number of factors that made repatriation the best option:

- The Contact Centre and other services were performing well, having undergone operational improvements over the years;
- Customer needs and expectations were evolving and BC Hydro wanted to own the end-to-end customer service experience;
- Cost savings were expected (for further information, please refer to Table 5-11);
- There was an opportunity to partner with MoveUp, the union that represents certain employees at both Accenture and BC Hydro, to provide employment opportunities for existing Accenture employees and obtain more favourable terms and conditions of employment to 2024;

- Repatriation provided operational flexibility, particularly in Customer Service, by allowing BC Hydro to have direct control and set team priorities. For example, BC Hydro is currently:
  - Working closely with consolidated billing customers to promote and support their transition to paperless billing following the completion of the Enterprise Billing Infrastructure Project; and
  - Improving escalation processes by restructuring Contact Centre roles to allow more customers to reach a work leader immediately rather than waiting for a call back.

  These changes would have been more difficult and costly to implement if BC Hydro had to negotiate change orders and statements of work with Accenture; and
- Repatriation also eliminated the requirement to share with Accenture future operational savings achieved through efficiency initiatives and eliminated the need for day to day management of Accenture.

5.6.2.2 Accenture Repatriation Benefits Have Exceeded Expectations

The net savings from repatriation have exceeded BC Hydro's original projections by $1.2 million and now total $8.2 million annually. Approximately 80 per cent of Accenture unionized employees accepted jobs at BC Hydro and there was a total FTE increase of 423 associated with the repatriation of staff and services.

Table 5-11 below shows the current forecasted annual net savings from the repatriation of services back to BC Hydro.

Table 5-11 Summary of Accenture Repatriation Savings and FTE Impact

KBU/Function	Services - ABS F2019 RRA ($ million) (1)	Services - ABS Reduction ($ million)	Incremental Operating Costs ($ million) (2)	Annual Operating (Costs) Savings ($ million) (3 = 1 - 2)	FTEs
Customer Service	27.8	(27.8)	21.9	5.9	281
Human Resources	5.1	(5.1)	3.5	1.6	32
Properties	1.8	(1.8)	0.4	1.4	7
Supply Chain	2.5	(2.5)	2.4	0.1	23
Technology	0.0	0.0	0.5	(0.5)	5
Communications and Community Engagement	0.0	0.0	0.7	(0.7)	7
Finance	0.0	0.0	0.3	(0.3)	2
Sub-Total	**37.2**	**(37.2)**	**29.8**	**7.4**	**357**
Tempworks[164]	4.2	(4.2)	4.2	0.0	0
Field Service Representatives[165]	7.9[166]	(7.9)	7.1	0.8	66
Total	**49.3**	**(49.3)**	**41.1**	**8.2**	**423**

5.6.3 FTE Increases since Fiscal 2012 have been Driven by BC Hydro's Capital Plan

In its Decision, the BCUC reviewed BC Hydro's FTE's over time.[167] Figure 5-8 below shows that apart from growth in the workforce directly related to increased capital investment, BC Hydro's FTEs have remained relatively flat since fiscal 2012. This

[164] Accenture previously provided Tempworks (i.e., temporary administrative and clerical support) services to BC Hydro. Rather than repatriating this function, BC Hydro decided to manage this function as part of its overall Contingent Labour Resource Augmentation Solution which will provide BC Hydro with a centralized, automated and standardized process for securing all contingent labour resource augmentation services and will provide greater visibility into the use of contingent labour across the whole organization.

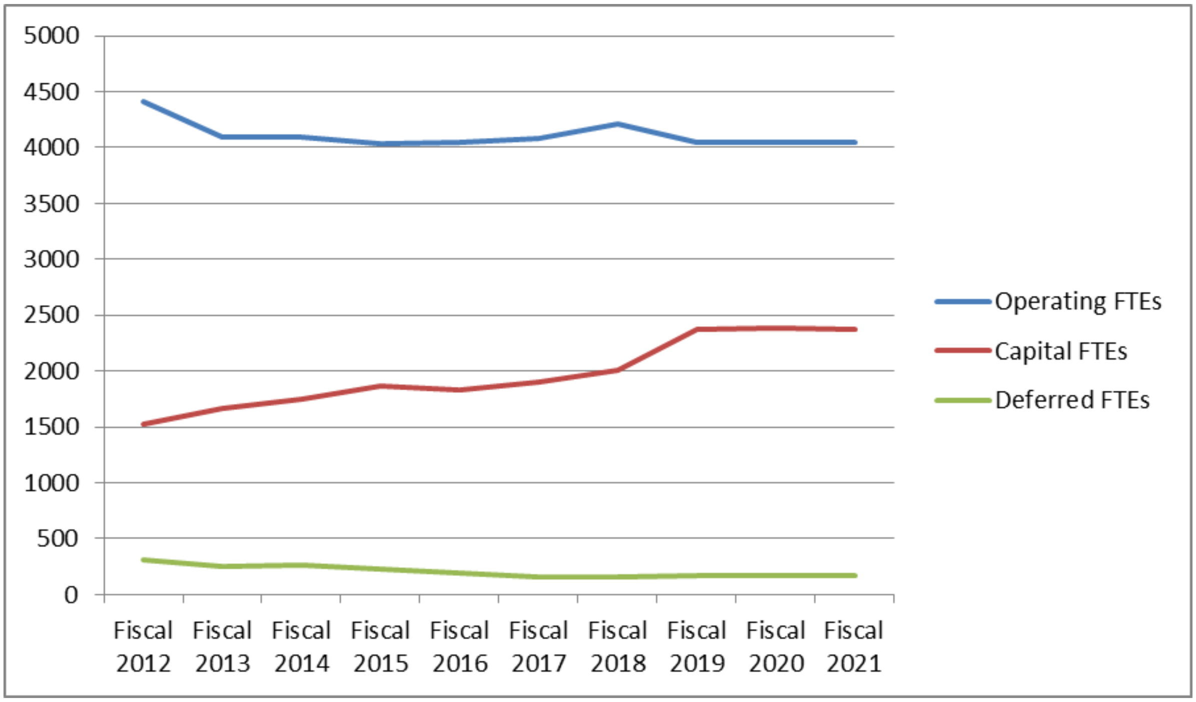
[165] Accenture provided manual meter reading services to BC Hydro starting in fiscal 2003. Starting in fiscal 2011, these services were provided under a separate time and materials contract that was renewed until automated meter reading, enabled by Smart Metering Infrastructure (SMI), stabilized. BC Hydro brought this function back in-house in fiscal 2017.

[166] At the time the forecast for the Previous Application was prepared, BC Hydro had not yet made a decision on how to manage the manual meter reading function. As Accenture had been providing manual meter reading services at that time, the ongoing cost of manual meter reading was budgeted as Accenture contract costs and not as internal labour.

[167] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), pages 34 to 35 and 87.

includes additions related to the Workforce Optimization Program, which have generated an estimated $18.5 million in cost savings, as discussed in section 5.6.1 above.

Figure 5-8 FTEs [168,169] (Fiscal 2012 to Fiscal 2021)



	Fiscal 2012 Actual	Fiscal 2013 Actual	Fiscal 2014 Actual	Fiscal 2015 Actual	Fiscal 2016 Actual	Fiscal 2017 Actual	Fiscal 2018 Actual	Fiscal 2019 Actual	Fiscal 2020 Actual	Fiscal 2021 Actual
Operating	4,415	4,096	4,089	4,089	4,042	4,082	4,209	4,051	4,047	4,043
Capital	1,527	1,662	1,752	1,872	1,828	1,905	2,013	2,378	2,383	2,370
Deferred	309	250	258	223	188	161	162	165	164	164
Total FTEs	**6,251**	**6,007**	**6,099**	**6,131**	**6,058**	**6,148**	**6,385**	**6,593**	**6,594**	**6,577**

As discussed in sections 5.6.1 and 5.6.2 above, the savings generated by the Workforce Optimization Program and the Accenture repatriation have caused

[168] Figure 5-8 shows total FTEs by work function (operating, capital or deferred), excluding FTEs related to the Accenture Repatriation, the Smart Metering Infrastructure Project and the Site C Project. These FTEs were removed to avoid skewing the trend line. All FTEs related to the Workforce Optimization Program, are included. The numbers for Fiscal 2012 to Fiscal 2018 are actuals. Fiscal 2019 numbers are forecast and fiscal 2020 and 2021 numbers are plan.

[169] "Deferred" FTEs, refers to FTEs whose work is charged to regulatory accounts. Almost all of BC Hydro's current deferred FTEs are charged to the DSM Regulatory Account.

BC Hydro's total FTEs to increase in recent years. Table 5-12 below provides a continuity schedule which highlights changes from the Previous Application.

Table 5-12 Continuity Schedule of Planned FTEs (Fiscal 2019 RRA Plan to Fiscal 2020 Plan to Fiscal 2021 Plan) [170, 171, 172, 173]

FTE's (including Regular and Overtime Hours)	Operations	Integrated Planning	Capital Infrastructure Project Delivery	Finance, Technology, Supply Chain	People, Customer, Corporate Affairs	Safety	Other	Total
F2019 RRA Plan FTEs (Schedule 16, line 52)	2,893	802	607	795	463	565	241	6,365
Workforce Optimization	146	74	136	114	46	14	5	536
Accenture Repatriation	-	-	7	30	387	-	-	423
Site C Project							240	240
F2019 Customer Metering adjustment					(1)			(1)
F2019 Safety - Business Continuity business case						2		2
Reduction in Appentice Intakes and Graduations						(107)		(107)
Impact of organization changes since F2017-F2019 RRA	(75)	74	(12)	7	(9)	17	(2)	-
Miscellaneous changes for overtime FTEs	24	(4)	(1)	1	3	(29)	21	13
Miscellaneous changes for regular hour FTEs	(2)	5	2	(1)	(1)	3	0	6
F2020 RRA Plan (Schedule 16, line 52)	2,984	952	739	946	887	464	505	7,477
Site C Project							12	12
Reduction in Appentice Intakes						(13)		(13)
Miscellaneous changes for overtime FTEs						(5)		(5)
F2021 RRA Plan (Schedule 16, line 52)	2,984	952	739	946	887	447	516	7,471

5.6.4 FTEs Are Expected to Remain Flat During the Test Period

Figure 5-9 below shows that, including overtime and excluding the Site C Project, total FTEs are expected to remain flat during the test period.[174]

170 Labour costs associated with FTEs working on the Site C Project are related to the natural progression of the work and are capitalized to the project, which means that they do not affect the test period revenue requirements.

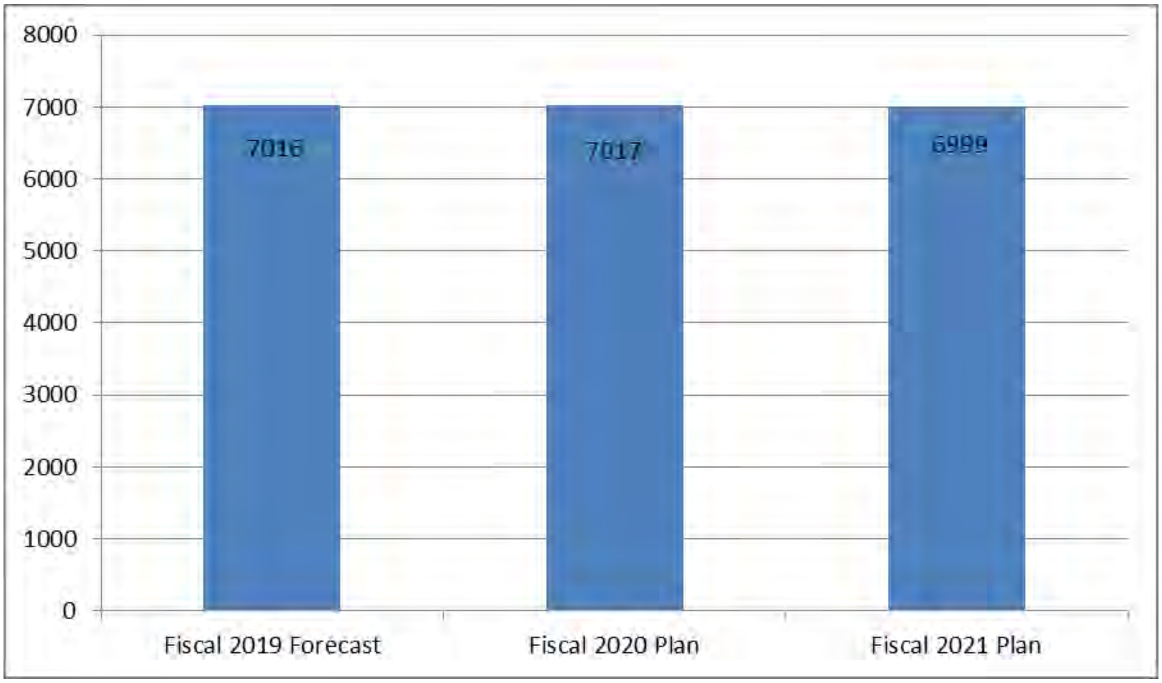
171 Miscellaneous changes for overtime FTEs are primarily related to increased FTEs in the Line Field Operations KBU from the Workforce Optimization Program as well as the Accenture repatriation and a ramp-up of the Site C Project. These increases are partially offset by reduction in forecast apprentice intakes and graduates in training.

172 The organization changes in Operations Business Group and Integrated Planning Business Group reflect the September 2018 re-organization discussed further in Chapter 5C, section 5C.6.2. This re-organization occurred after the fiscal 2019 forecast was finalized.

173 Apprentice intakes reduced by 107 from fiscal 2019 RRA plan to fiscal 2020 RRA plan due to a reduction in forecast resourcing requirements.

174 FTEs are increasing from 7,405 (fiscal 2019 forecast) to 7,477 (fiscal 2020 plan), for a net increase of 72 FTEs. The Site C Project is increasing by 71 FTEs from fiscal 2019 forecast to fiscal 2020 plan. Labour costs associated with FTEs working on the Site C Project are capitalized to the project, which means that they do not affect the test period revenue requirements. If FTE increases for the Site C Project are factored out, the overall increase in FTEs from fiscal 2019 forecast to fiscal 2020 plan is just one FTE.

Figure 5-9 Total FTEs (including overtime, excluding Site C)



Planned FTEs, including the Site C Project, are 7,477 for fiscal 2020 and 7,471 for fiscal 2021.[175, 176] Further detail is provided in Table 5-13 below.

[175] Total FTEs are not equivalent to the total number of people actually employed by BC Hydro at a point in time as the annual FTE budget is based on total hours planned for the year, divided by the annual standard labour hours by affiliation. The total hours planned include full time, part time and temporary staff (i.e., seasonal hires) as well as overtime. As at January 31, 2019, BC Hydro's total active headcount was 6,681.

[176] Total planned Site C FTEs are 460 in fiscal 2020 and 472 in fiscal 2021.

Table 5-13 Summary of FTE Changes (Fiscal 2019 Forecast to Fiscal 2020 Plan)

Item	FTEs
Fiscal 2019 Forecast FTEs	7,405
Workforce Optimization Program	61
Reduction to Apprentices and Trainees (see Chapter 5D, section 5D.5.2)	(32)
Reduction in planned overtime	(29)
Site C Project	71
Fiscal 2020 Plan FTEs	7,477[177]

FTEs represent the employee workforce which performs operating, capital and deferred work across BC Hydro. Table 5-14 below provides a breakdown of FTEs by these work functions.[178]

[177] Numbers do not add exactly due to rounding.

[178] FTEs related to capital overhead are shown within the Operating category. For further details on FTEs, please see Appendix A, Schedule 16.0.

Table 5-14 Total FTEs by Function

FTEs (including Overtime)	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Operating								
Integrated Planning	437	478	438	483	435	459	536	536
Capital Infrastructure Project Delivery	301	267	303	287	302	315	316	318
Operations	1,673	1,768	1,674	1,779	1,674	1,689	1,641	1,644
Safety	377	422	377	416	377	364	340	333
Finance, Technology, Supply Chain	737	767	744	823	750	867	874	874
People, Customer, Corporate Affairs	309	341	308	384	308	740	722	722
Other	37	39	38	36	38	41	40	40
Total (Schedule 16 line 69)	3,872	4,082	3,881	4,209	3,884	4,474	4,470	4,466
Percentage Change						15%	0%	0%
Capital								
Integrated Planning	365	325	365	346	367	411	416	416
Capital Infrastructure Project Delivery	276	307	301	360	302	418	418	417
Operations	1,215	1,077	1,219	1,100	1,219	1,344	1,343	1,340
Safety	186	154	188	152	188	138	124	114
Finance, Technology, Supply Chain	31	36	39	46	44	54	70	70
People, Customer, Corporate Affairs	8	6	8	8	8	8	8	8
Other	189	168	192	227	202	394	465	477
Total (Schedule 16 line 70)	2,269	2,072	2,311	2,239	2,329	2,766	2,843	2,841
Percentage Change						19%	3%	0%
Deferred								
Integrated Planning	0	0	0	0	0	0	0	0
Capital Infrastructure Project Delivery	3	7	3	5	3	4	4	4
Operations	0	1	0	0	0	0	0	0
Safety	0	0	0	0	0	0	0	0
Finance, Technology, Supply Chain	2	2	2	2	2	2	2	2
People, Customer, Corporate Affairs	150	150	147	153	147	158	158	158
Other	1	1	1	1	1	0	0	0
Total (Schedule 16 line 71)	155	161	152	162	152	165	164	164
Percentage Change						8%	0%	0%
Total								
Integrated Planning	802	804	802	830	802	870	952	952
Capital Infrastructure Project Delivery	579	581	607	652	607	737	739	739
Operations	2,889	2,845	2,893	2,880	2,893	3,033	2,984	2,984
Safety	563	576	565	568	565	501	464	447
Finance, Technology, Supply Chain	769	805	784	871	795	924	946	946
People, Customer, Corporate Affairs	467	497	463	545	463	906	887	887
Other	227	208	231	264	241	434	505	516
Total (Schedule 16 line 72)	6,296	6,315	6,344	6,611	6,365	7,405	7,477	7,471
Percentage Change						16%	1%	0%

5.6.5 Our Total Rewards Package Helps to Retain Employees and is Consistent with Market Rates

Labour costs are one of BC Hydro’s largest operating costs, and reflect the compensation paid to employees. BC Hydro’s total rewards offer includes salary, pension, benefits and time off. In its Decision, the BCUC stated that the costs and benefits of BC Hydro's total rewards initiatives were unclear.[179] BC Hydro has provided additional information in the following sections to improve clarity in this regard. The information shows that customers are getting good value from BC Hydro's total rewards offer.

5.6.5.1 Attracting and Retaining Employees Is Critical

BC Hydro's total rewards offer includes salary, pension, benefits and time off (i.e., vacation days). It is designed to attract and retain qualified employees. A low turnover rate is important because some of the skillsets required by BC Hydro are specialized, and the complexity of our assets and operations require an experienced workforce. These skills and experience are difficult to find in the market and require significant time and costs to develop.

5.6.5.2 Benchmarking Shows Wages are Below Market, While Total Rewards are at the Market

A 2017 assessment by Morneau Shepell concluded that, on an average total cash basis, BC Hydro employees earn 11 per cent less than median market rates. After factoring-in the value of pension benefits and time off programs, BC Hydro's compensation package is comparable, at 2 per cent below median market rates.

The design of our total rewards offer has proven to be effective in attracting and retaining employees. For example, our voluntary turnover rate is 1.3 per cent, which is below the 3.8 per cent average for the Power and Utilities industry as reported by the Conference Board of Canada.[180]

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[179] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 34.

[180] MacLean, Kathryn, and Allison Cowan. *Compensation Planning Outlook 2019*. Ottawa: The Conference Board of Canada, 2018.

5.6.5.3 Standard Labour Rates in the Test Period Impacted by Employer Health Tax and BCUC-Directed Pension Adjustment

As in the Previous Application, the test period revenue requirements reflect Standard Labour Rates and Standard Labour Hours calculated by BC Hydro. The Standard Labour Rates in the test period are impacted by BC Hydro's bargaining mandate, the implementation of the Employer Health Tax, and the allocation of the compliance filing adjustment on current service pension costs in accordance with the BCUC's Decision on our Previous Application.

As part of the budgeting process and for actual cost distribution, BC Hydro uses Standard Labour Rates and Standard Labour Hours to assign payroll, benefits, and current service pension costs to departments, work activities, projects, and work orders. These rates are calculated at the beginning of each budgeting cycle and are based on forecasts of wage and salary increases, employee benefits, current service pension costs, gainsharing under our union contracts, sick days, annual vacation, and flex day entitlements. Table 5-15 below provides the weighted average Standard Labour Rate and the Standard Labour Hours for each affiliation. The increases to these rates reflect the cost increases described in section 5.5.2.2 above.

Table 5-15 Standard Labour Rates by Affiliation

Affiliation	Standard Labour Hours	F2019 Forecast ($)	F2020 Plan ($)	F2021 Plan ($)
MoveUp	1,535	56.55	59.28	60.31
International Brotherhood of Electrical Workers	1,461	77.16	81.67	83.15
Management and Professionals	1,621	97.66	100.69	102.48

The increase in Standard Labour Rates from fiscal 2019 forecast to fiscal 2020 plan is higher than the increase from fiscal 2020 plan to fiscal 2021 plan. This is primarily due to the implementation of the Employer Health Tax (which is effective January 1, 2019) and the allocation of the compliance filing adjustment on current service pension costs to KBUs, through the Standard Labour Rates, in fiscal 2020.

The Employer Health Tax is partially offset by the elimination of Medical Services Plan premiums (which is effective January 1, 2020). As discussed in Chapter 7, section 7.8.11, the elimination of Medical Services Plan Premiums significantly reduced the balance in the Non-Current Pension Costs Regulatory Account.

5.7 Benchmarking Support the Reasonableness of BC Hydro's Operating Costs

In its Decision on our Previous Application, the BCUC noted the absence of evidence that BC Hydro uses benchmarking. BC Hydro does use benchmarking internally in areas of the business where it makes sense to do so, while recognizing the inherent limitations of benchmarking in many cases. We have also undertaken additional benchmarking on operating costs in specific response to the BCUC's observation. This section focuses on the following:

- An independent benchmarking study prepared by The Brattle Group for this proceeding, which confirms that BC Hydro's operating costs compare well against an appropriate peer group of U.S. utilities. This study is provided as Appendix T;
- The results of a comparison of our operating costs against those of other major electric utilities in Canada, which suggests that BC Hydro's operating costs also compare favourably against major Canadian utilities;
- The results of recent independent benchmarking on maintenance delivery costs, which demonstrates that BC Hydro's costs are consistent with or better than our utility peers; and
- A summary of benchmarks and metrics provided to support the operating costs and FTEs for various KBUs as discussed in Chapters 5A through 5G.

5.7.1 BC Hydro Benchmarks Well Against U.S. Peer Group (Brattle Group Report)

In response to the BCUC's comments about benchmarking in its Decision, we retained The Brattle Group to conduct an independent benchmarking study on BC Hydro's operating costs (Brattle Group Benchmarking Study). The Brattle Group Benchmarking Study found that BC Hydro benchmarks favourably against a U.S. peer group that The Brattle Group had selected. While The Brattle Group determined that the level of depth in its study was appropriate for general cost comparisons, it also cautioned that definitive conclusions should not be drawn from benchmarking studies of this nature.

5.7.1.1 The Brattle Group has Significant Experience in Benchmarking

BC Hydro selected The Brattle Group to perform the study because of The Brattle Group's considerable experience in benchmarking. William P. Zarakas, a Principal of The Brattle Group, led the study. In the report, included as Appendix T, Mr. Zarakas certifies his independence and his duty to the BCUC. He explains that the analysis he and his team undertook was peer reviewed by others in The Brattle Group.

5.7.1.2 The Brattle Group Benchmarked Total Operating Costs, Costs by Function and Costs by Sub-Function

The Brattle Group Benchmarking Study compared BC Hydro's operating costs at a higher level, and at a more granular level by function and sub-function.

The study focused on operations and maintenance costs, excluding the costs of fuel and water rentals that are used in the power production process. The study refers to these costs as "non-fuel operations and maintenance expenses", or by the acronym "NFOM". Costs of fuel and water rentals used in the power production process were excluded from the study because they are reflected in BC Hydro's Cost of Energy, not operating costs. For simplicity, we refer to non-fuel operating and maintenance costs as "operating costs" in the remainder of this section. We have addressed BC Hydro's Cost of Energy in Chapter 4 of this Application.

The Brattle Benchmarking Study benchmarked operating costs as follows:

- Total operating costs.
- By function:
  - Operating costs not related to power production operations; and
  - Operating costs related to power production operations.

The Brattle Group considered the more granular functional analysis to be more informative than benchmarking at the level of overall operating costs. As a further test, The Brattle Group then broke down the non-power production costs into transmission, distribution, administrative and customer costs.

In terms of process, The Brattle Group identified an appropriate peer group of U.S. utilities. The decision to look at U.S. utilities, rather than Canadian utilities, was due to the availability of consistent data. U.S. utilities, unlike Canadian utilities, report annually using the Federal Energy Regulatory Commission's Uniform System of Accounts. The Brattle Group adjusted the presentation of BC Hydro's cost data where necessary to ensure that it was comparable with how the peer utilities were reporting their costs. The Brattle Group also identified the appropriate metrics for use in this type of benchmarking as being costs per MWh[181] and costs per customer, which are standard metrics for this type of benchmarking.

5.7.1.3 BC Hydro Benchmarks in the Top (i.e. Best) Quartile

The Brattle Group Benchmarking Study concludes that BC Hydro's operating costs compare favourably to the peer group on an overall basis, as well as at the more granular level. This is true regardless of which metric is used.

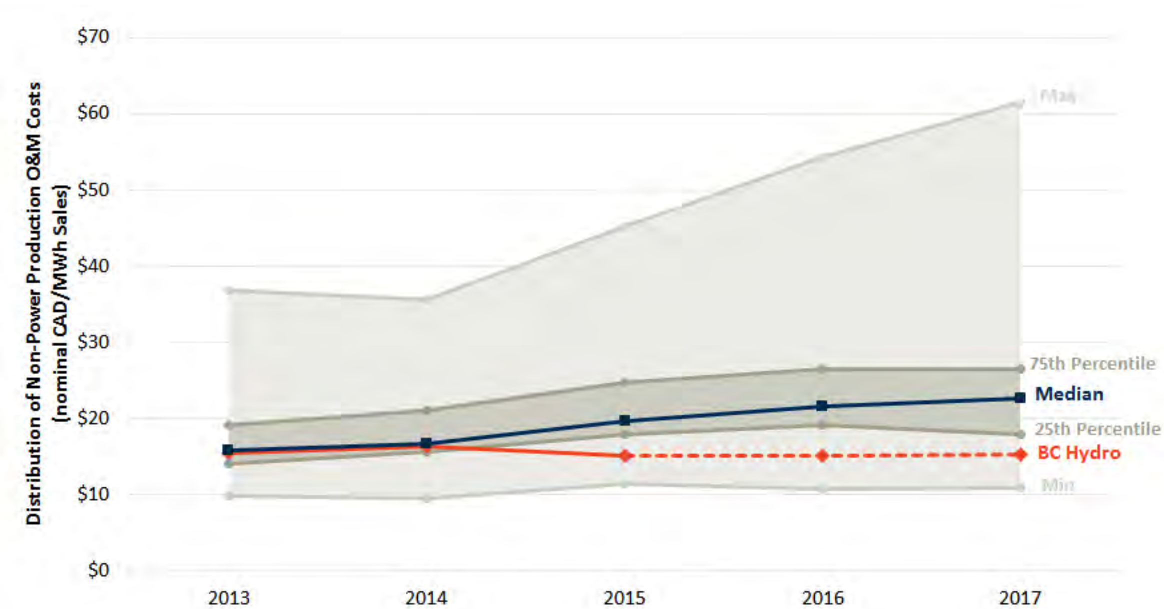
As an owner of large hydroelectric generation, BC Hydro has some inherent cost advantages over utilities more reliant on small hydro or thermal generation.

[181] In the case of power production, the focus is on costs per MWh generated, whereas it is MWh delivered for non-power production costs.

Therefore, the non-power production costs, which The Brattle Group benchmarked overall at the functional level as well as by sub-function (transmission, distribution, administrative) provide the most useful indication of BC Hydro's relative cost performance, as they are far less affected by the nature of power production at a particular utility.

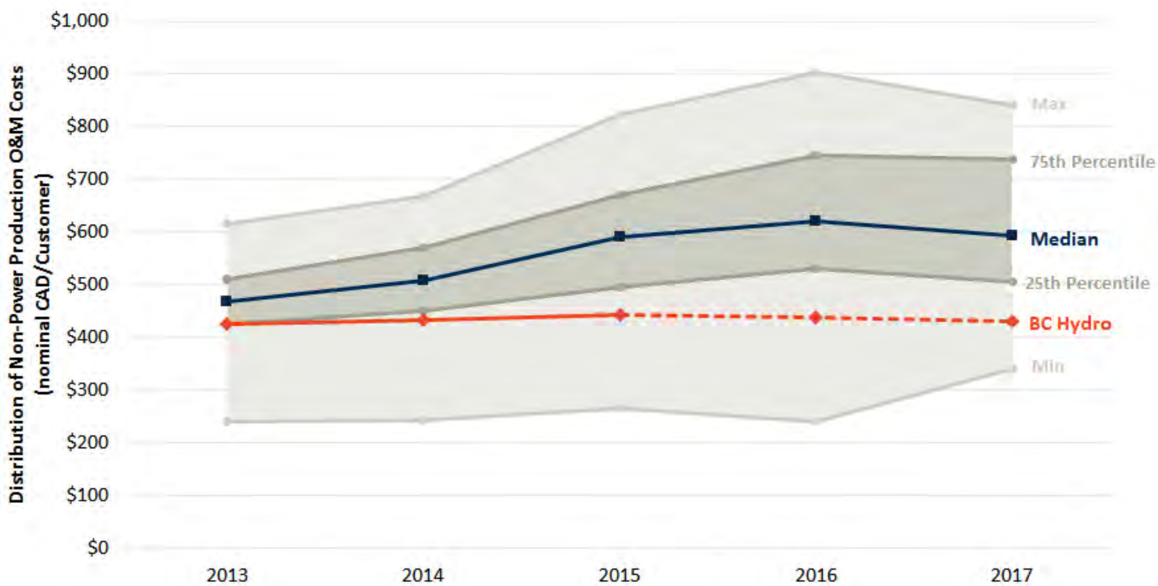
As shown in Figure 5-10 and Figure 5-11 below, BC Hydro is in the top (i.e., best) quartile for non-power production costs (e.g., transmission, distribution, administrative), and our relative performance appears to have improved in recent years.

Figure 5-10 Non-Power Production NFOM ($ per Customer) [182]



[182] Appendix T, page 19.

Figure 5-11 Non-Power Production NFOM ($ per Delivered MWh) [183]



Based on the results of the benchmarking study, The Brattle Group concludes:

> "Excluding power production from NFOM provides a meaningful indicator for BC Hydro's comparative cost performance…
> BC Hydro was in the 2nd quartile of unit cost performance for this metric in the early years of this study (2013) and improved to the 1st quartile by 2015, mainly due to improvements in its cost performance in transmission and distribution."

5.7.2 BC Hydro Has Also Provided an Indicative Comparison to Major Canadian Electric Utilities

As indicated above, The Brattle Group Benchmarking Study used a peer group of U.S. utilities, largely due to the availability of consistent data. Whereas U.S. utilities report costs on a consistent basis, Canadian utilities do not report in the same way. That said, we wanted to provide the BCUC with some indication of how BC Hydro's operating costs compare relative to those of other major Canadian utilities.

BC Hydro conducted a review internally to compare our operating costs against

[183] Appendix T, page 19.

those of FortisBC Inc., Manitoba Hydro, and Hydro Quebec. The comparison, which should be treated as a high-level indication only, suggests that BC Hydro's operating costs compare favourably against the costs of other major Canadian utilities.

5.7.2.1 The Canadian Utility Comparison Is Indicative

In terms of process, BC Hydro conducted a limited review of recent years of published annual reports and rate applications, where applicable, of:

- Manitoba Hydro;
- Hydro Quebec; and,
- FortisBC Inc.

The process involved reviewing and assessing each entity's operating costs, number of customers, and sales volume and making assumptions in order to align these items to ensure some degree of consistency. The operating cost basis for each of the entities compared may be subjective as the detailed breakdown was not provided in the published reports. We have used our best efforts to provide a comparable basis for each item included in the calculation of the metrics shown in Figure 5-12 and Figure 5-13 below. Other challenges in comparing financial data relate to the use of different accounting standards (IFRS versus U.S. GAAP), the use of regulatory accounting, and whether entities are consolidated or not. This review may not have identified all of the relevant documents as different entities have different regulatory application formats and different financial statement and annual report formats, and different online locations of their information.

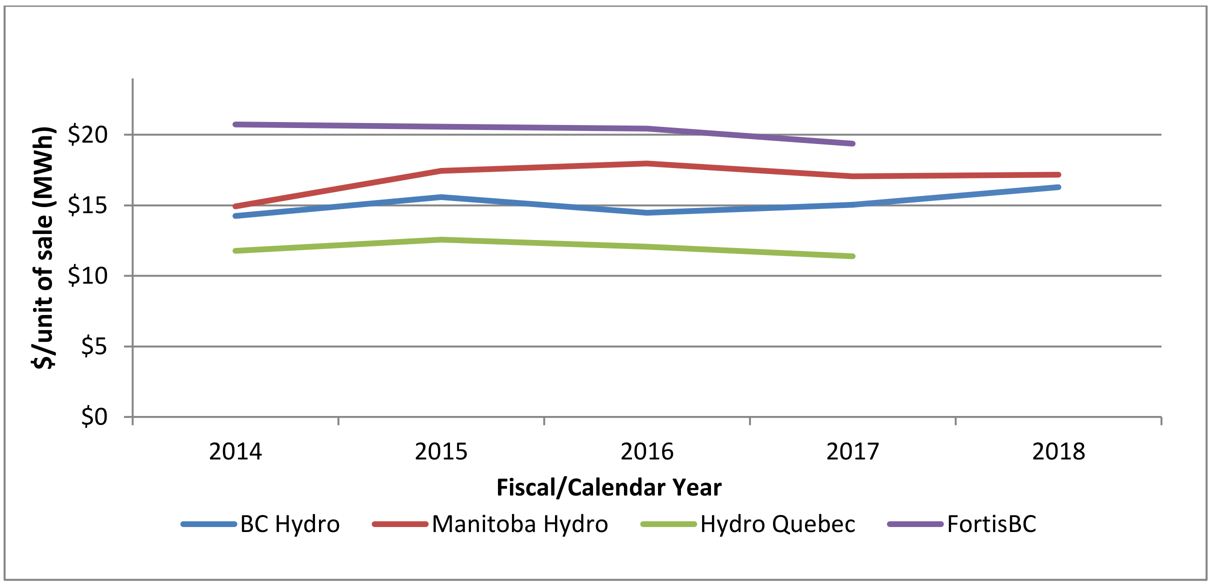
BC Hydro performed the comparison using the metrics identified as appropriate by The Brattle Group Benchmarking Study, which are dollars per customer and dollars per MWh. Data for Hydro Quebec and FortisBC Inc. was not available for 2018 as these entities report on a December 31 calendar year-end basis.

5.7.2.2 The Results Suggest that BC Hydro Compares Favourably

As shown in Figure 5-12 and Figure 5-13 below, this internal review indicates that BC Hydro's operating costs are in line with those of other Canadian utilities on both a per MWh and a per customer basis.[184]

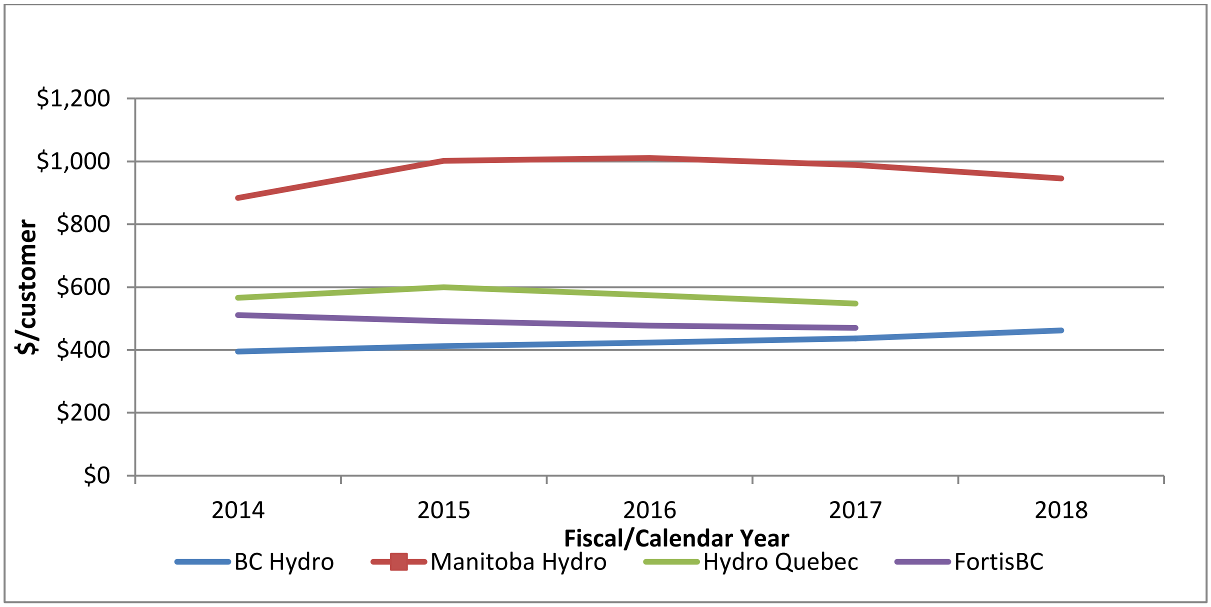
Consistent with the caution by The Brattle Group about the limits of benchmarking, we recognize that extraneous factors can influence these metrics. For instance, the rank order of the utilities changes depending on the metric used. To some degree, this would likely be a product of the fact that Manitoba Hydro and FortisBC Inc. have relatively few customers, but have significant generation output (Manitoba Hydro in particular exports a significant portion of its energy output). As such, when evaluating these results, we look more to the fact that BC Hydro is within the same range as these utilities when it comes to operating costs, as opposed to any particular rank ordering.

Figure 5-12 Total Operating Costs per MWh of Sales (BC Hydro Review)



184 For purposes of this analysis, BC Hydro's operating costs refer to net operating costs, which are described in section 5.5.1. Total operating costs for Manitoba Hydro, Hydro Quebec, and FortisBC are sourced from their publicly available annual reports.

Figure 5-13 Total Operating Costs per Customer (BC Hydro Review)



5.7.3 BC Hydro Benchmarks Well on Maintenance Costs

Maintenance costs are well suited to benchmarking between companies, since cost data can be compared relative to common industry performance indicators. External benchmarking studies on maintenance costs, undertaken by Navigant and First Quartile, are used as part of BC Hydro’s routine business practices. The studies provide a more granular view of maintenance costs than the Brattle Benchmarking Study discussed above. Recent benchmarking results have shown that BC Hydro’s maintenance and operating cost performance is either consistent with or better than our utility peers.

5.7.3.1 Maintenance Benchmarking is Completed Regularly by Independent Experts

BC Hydro retains two independent experts in utility benchmarking, Navigant and First Quartile, to provide maintenance benchmarking services:

- **First Quartile (transmission and distribution):** First Quartile Consulting offers benchmarking services to help utilities compare performance and identify areas of opportunity in comparison to industry peers. Using benchmarks from 41 operating companies, First Quartile provides normalized comparisons between companies across various maintenance categories including distribution, transmission, vegetation and stations; and

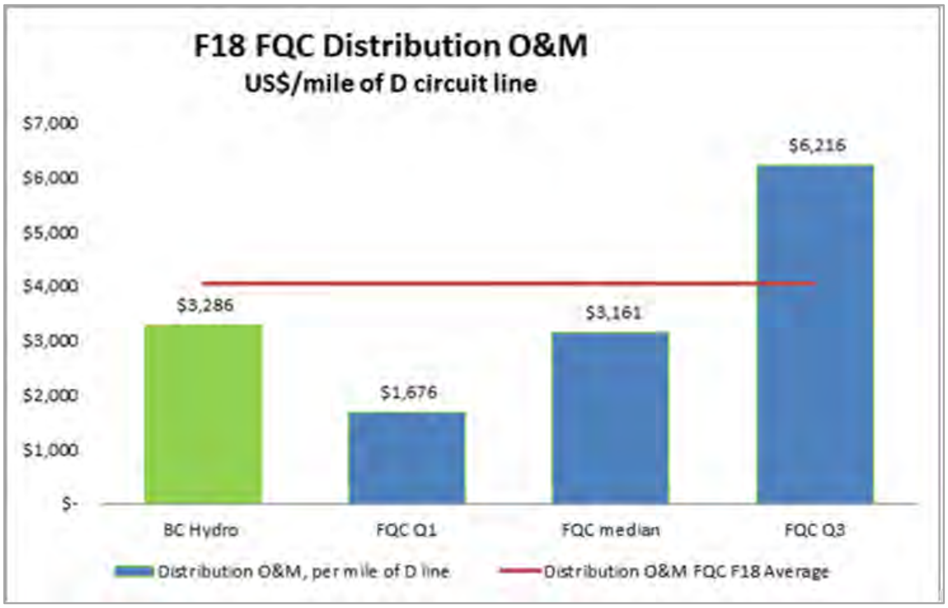
- **Navigant (generation):** Navigant's GSK Hydro Benchmarking program is focused on generation. BC Hydro has been participating in this program for 20 years. The benchmarking peer group includes over 500 generation stations, comprised of about 1,800 units that represent approximately 106,000 MW of installed capacity. Participants in the program are predominately from the United States and Canada, but also include companies from around the globe including Europe, New Zealand and South America. The stations included are diverse in size, type of facility and age, and include a mix of run-of-river, reservoir, pumped storage and pumping stations. Accordingly, the stations are grouped into approximately 300 station groups and study results are presented on a group basis for comparability.

5.7.3.2 Our Transmission and Distribution Lines Costs are Below Average

In the benchmarking studies performed annually by First Quartile, the experts compare the transmission and distribution line maintenance costs of approximately 40 utilities.

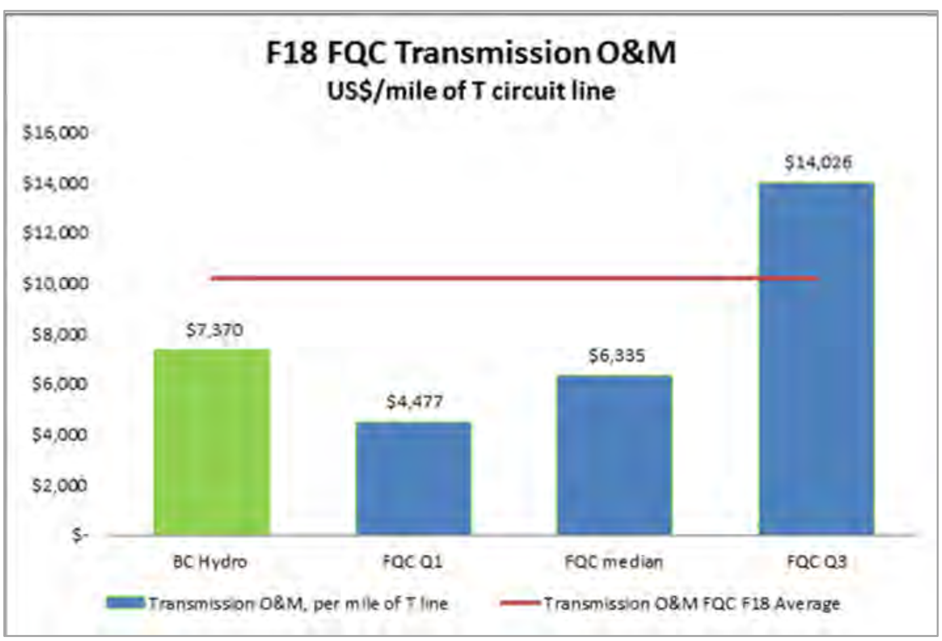
As shown in Figure 5-14 below, First Quartile has found that BC Hydro's operations and maintenance costs were below the average for the utilities included in the distribution category.

Figure 5-14 Distribution Line Operations and Maintenance Costs



Similarly, as shown in Figure 5-15 below, BC Hydro's operations and maintenance costs were below the average for utilities included in the transmission category.

Figure 5-15 Transmission Line Operations and Maintenance Costs

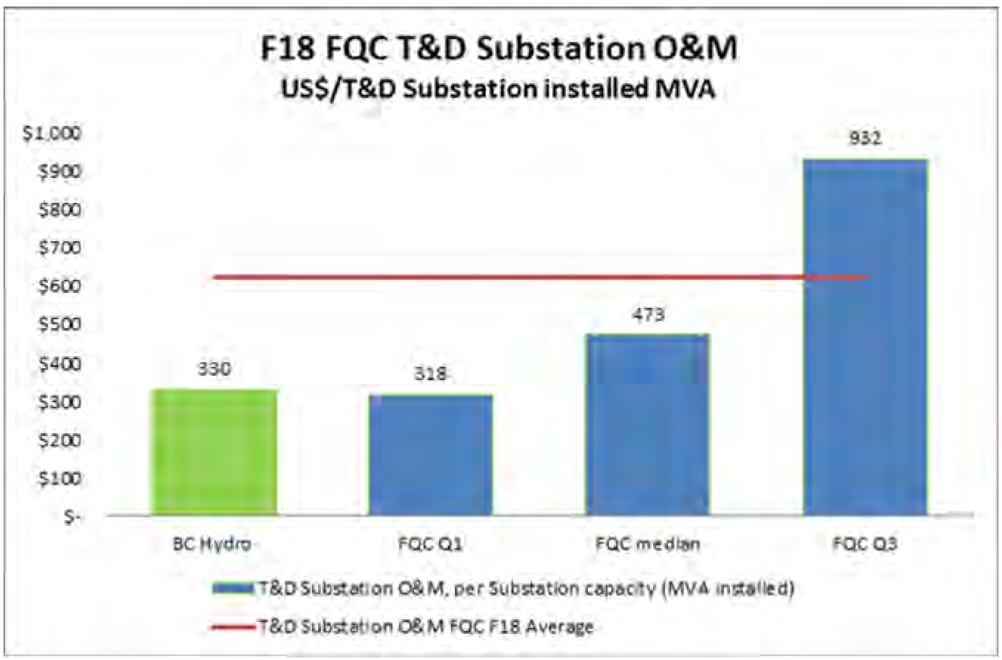


It is important to note that the distribution and transmission peer groups included some U.S. utilities with less challenging terrain and climate than BC Hydro's service area. BC Hydro's mountainous terrain and colder climate could be expected, other things being equal, to increase maintenance costs.

5.7.3.3 Our Transmission and Distribution Stations Costs are Below Average

The annual First Quartile benchmarking results also showed that BC Hydro's operations and maintenance costs were below average (i.e., favourable) for Transmission and Distribution Stations. In fact, as shown by Figure 5-16 below, BC Hydro is only slightly above the first (i.e., best) quartile of the peer group.

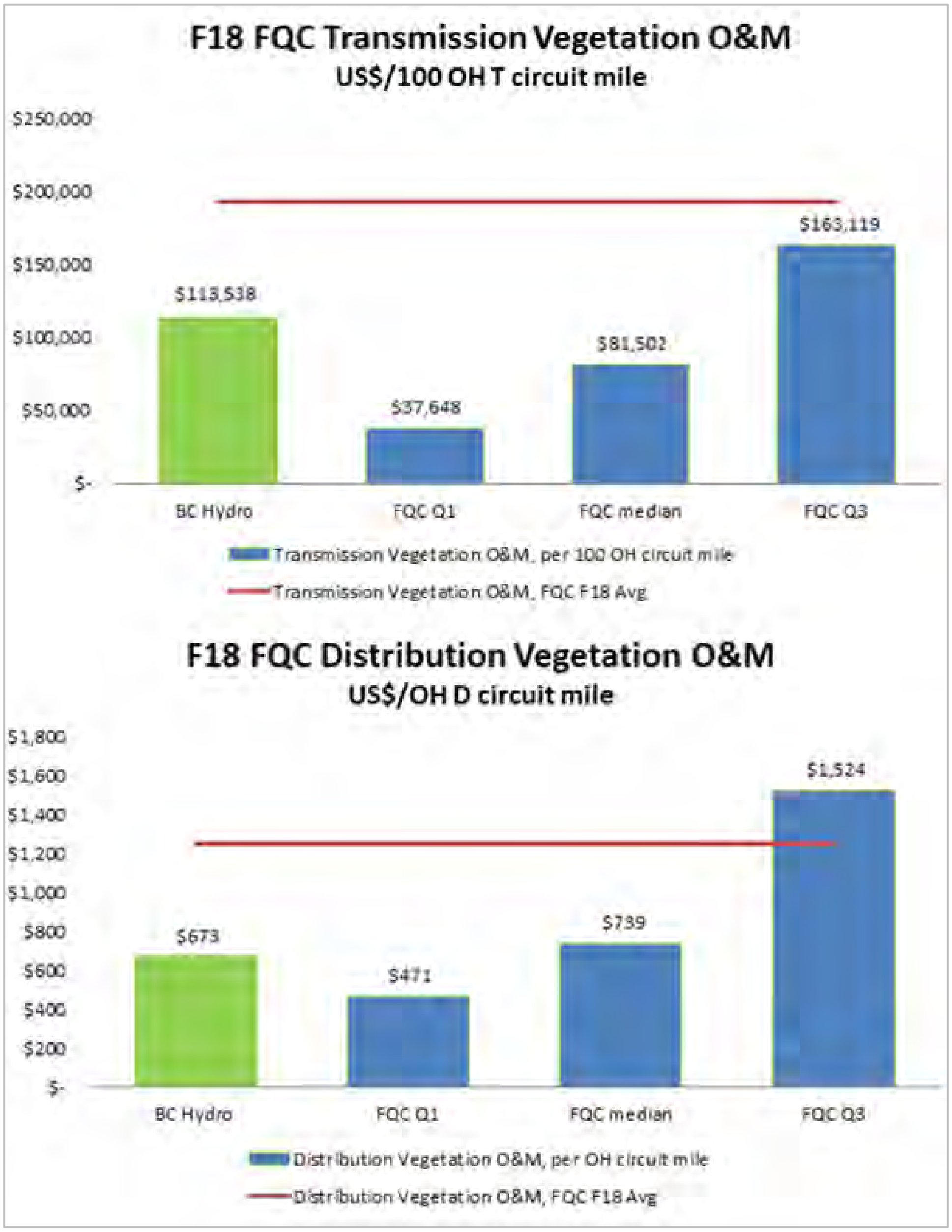
Figure 5-16 Transmission and Distribution Stations Operations and Maintenance Costs



5.7.3.4 Our Transmission and Distribution Vegetation Maintenance Costs Are Below Average

As shown in Figure 5-17 below, the annual First Quartile benchmarking results also show that BC Hydro's vegetation operations and maintenance costs are below average when compared to our utility peers. Many of the utilities included in this peer group have less challenging terrain and geography than BC Hydro's service area.

Figure 5-17 Transmission and Distribution Vegetation Operations and Maintenance Costs



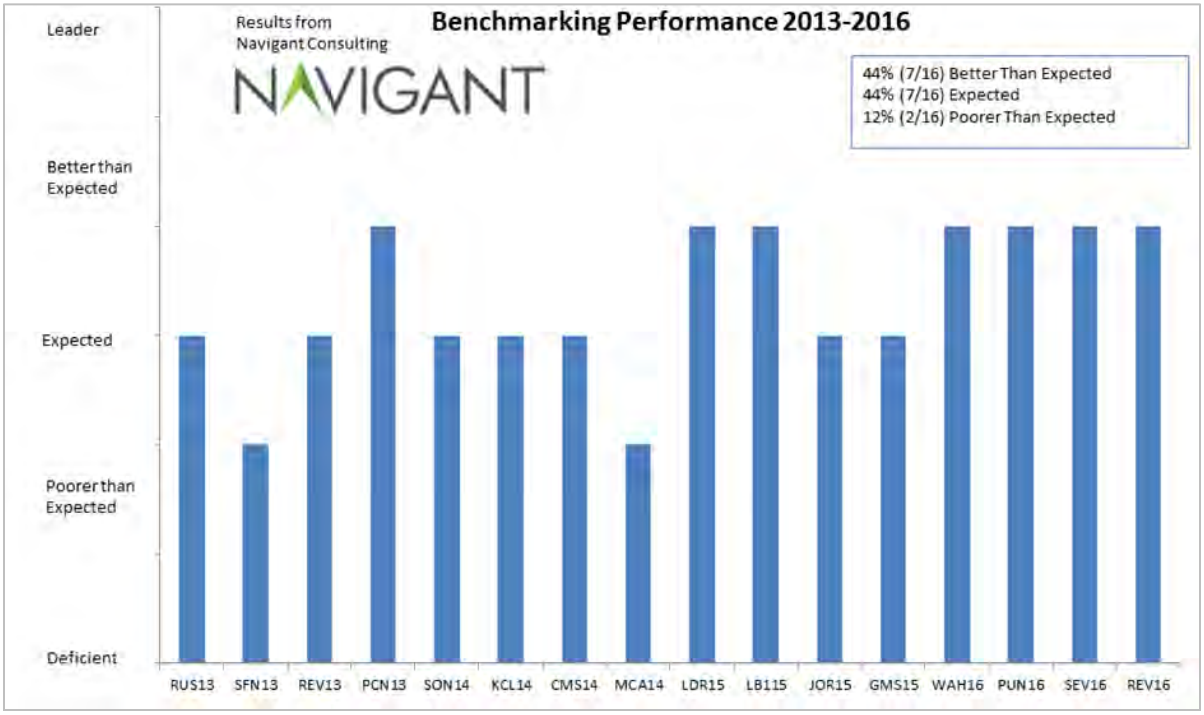
5.7.3.5 Our Generation Station Maintenance Costs Are Favourable

Benchmarking of generation station maintenance costs reveals a similar pattern, with BC Hydro being low cost relative to other hydroelectric stations of a similar age and size.

BC Hydro participates in Navigant Consulting's GSK Hydro Benchmarking program each year, using four generation stations to compare maintenance and operating costs against a designated peer group of hydroelectric generating stations. The stations selected change from year to year and are periodically re-examined to provide historical cost progression comparisons. Navigant performs an in-depth cost review on each station, and produces a report comparing BC Hydro's stations to other hydroelectric stations within the designated peer group. In order to provide the BCUC with a representative sample of BC Hydro's generation station performance, we have assembled the results of the 16 most recent Navigant reviews in Figure 5-18 below.

As shown in Figure 5-18, Navigant's reviews of these 16 stations showed that 88 per cent of BC Hydro's stations sampled were performing as expected or better in maintenance and operations costs, where "better" represents lower costs than expected.

Figure 5-18 Generation Stations Benchmarking Performance – 2013 to 2016 [185]



These results confirm that BC Hydro's generation station maintenance costs are favourable when compared to our utility peers. The Navigant studies control for type, size and age of generation facilities which means that this comparison is not as influenced by the inherent economies of scale associated with our large hydroelectric generation.

Navigant noted that leading performers adopt business practices that include the following:

- Management of the generation fleet using asset management principles;
- Plant automation and centralized dispatch (operation and control) of generating stations;

[185] The lower cost performance for Stave Falls (**SFN**) and Mica (**MCA**) were related sizeable capital investments in the benchmark year including spillway projects at Stave Falls and the Mica Unit 5 and Unit 6 project.

- Operation of generating units in efficient load zones;
- Workforce flexibility in medium and small stations (i.e., the workforce operates and maintains multiple stations); and
- Improved work planning and cost visibility.

BC Hydro has adopted these business practices to manage our maintenance costs effectively.

5.7.4 KBUs Use Various Benchmarks for Internal Purposes

The evidence that BC Hydro put forward in the Previous Application did not include information on benchmarks used internally by BC Hydro for management purposes. As a result, there may be an impression that BC Hydro does not use benchmarking for internal purposes. While not all KBUs lend themselves to the use of benchmarks, many KBUs do use benchmarks to help inform management decisions.

The Morneau Shepell compensation benchmarking discussed in section 5.6.5.2 above and the Navigant and First Quartile maintenance benchmarking, discussed in section 5.7.3 above, are three notable examples of our regular use of benchmarking. A number of additional examples as summarized in Table 5-16 below.

Table 5-16 Summary of KBU Benchmarks and Metrics

KBU	Benchmark	BC Hydro Position	Peer Group
Finance (Chapter 5E, section 5E.4)	Number of internal staff in Accounting and Finance	181[186]	180 (median)[187]
Finance (Chapter 5E, section 5E.4)	Cost of internal staff in Accounting and Finance as a percentage of overall revenues	0.49%[188]	0.5% (bottom (best) quartile) 0.8 (median)[187]
Safety System and Assurance (Chapter 5D, section 5D.4)	Operating Costs per Visitor Day for public use management areas	$1.03 per visitor day[189]	$2.17 or $1.16 after accounting for revenues from user fees[190]
Supply Chain (Chapter 5E, section 5E.6)	Number of Invoices Processed per FTE Annually	6,086[191]	4,706[191]
Supply Chain (Chapter 5E, section 5E.6)	On-Time Invoice Payment	92%[192]	90%[192]
Supply Chain (Chapter 5E, section 5E.6)	Service Fill Rates	97%	96%[193]
Human Resources (Chapter 5F, section 5F.4)	Ratio of Human Resources FTEs to Overall FTEs	1:59[194]	1:54[194]
Human Resources (Chapter 5F, section 5F.4)	Ratio of Recruiters to Recruitment Requisitions	1:34	1:25[195]
Human Resources (Chapter 5F, section 5F.4)	Sick Days per Employee	7.0	9.0[196]

186 The Finance KBU has 204 FTEs. However, this total includes 23 FTEs that perform business planning, change management and enterprise risk management functions which are not traditional finance and accounting functions. Excluding these FTEs, the total number of FTEs in the Finance KBU is 181.

187 Companies with annual revenue of $5 billion and higher.

188 The Finance KBU has a base operating cost budget of $30.8 million which equates to approximately 0.49 per cent of BC Hydro's total fiscal 2018 revenues of $6.237 billion.

189 Based on fiscal 2019 numbers.

190 BC Parks operating costs/visitor days in most recent annual report. http://www.env.gov.bc.ca/bcparks/research/statistic_report/statistic-report-2015-2016.pdf?v=1547851037669.

191 2017 American Productivity and Quality Centre (APQC)benchmark, https://www.apqc.org/benchmarkig-portal/osb/accounts-payable-and-expense-reinbursement.

192 The Hackett Group, https://www.zycus.com/knowledge-hub/research-reports/three-characteristics-of-top-performing-purchase-to-pay-organizations.html.

193 PWC 2017 Utilities Materials Logistics Benchmark Study.

194 2017 HR Annual Metrics Report, HR Metrics Service, 2017.

195 Mariotti, Andrew, *2017 Talent Acquisition Benchmarking Report*, Society for Human Resource Management, https://www.shrm.org/hr-today/trends-and-forecasting/research-and-surveys/Documents/2017-Talent-Acquisition-Benchmarking.pdf.

196 MacLean, Kathryn, and Allison Cowan. *Compensation Planning Outlook 2019*. Ottawa: The Conference Board of Canada, 2018.

KBU	Benchmark	BC Hydro Position	Peer Group
Human Resources (Chapter 5F, section 5F.4)	Return to Work Duration	4 Weeks	6.6 Weeks[197]
Human Resources (Chapter 5F, section 5F.4)	Voluntary Turnover Rate	1.3	3.8[196]

Further discussion of these benchmarks are provided as part of the operating costs and FTEs discussion for various KBUs in Chapters 5A through 5G. Overall, these benchmarks provide additional comfort that we are managing operating costs appropriately.

5.8 BC Hydro Is Optimizing Power System Maintenance

Ongoing maintenance of the Power System is necessary for assets to achieve their expected performance throughout their lifecycle. The Integrated Planning Business Group, discussed in Chapter 5A, holds the Power System maintenance budget and is responsible for maintenance investment decisions. The Operations Business Group, discussed in Chapter 5C, is responsible for executing maintenance work.

5.8.1 Aging and Growing Asset Base, Increased Severe Weather Events, Outstanding Needs, and Additional Requirements are Driving Increased Costs

Power System maintenance is budgeted at approximately $235 million per year during the test period, representing approximately 30 per cent of BC Hydro's forecast base operating costs. BC Hydro is planning to increase the budget for Power System maintenance during the test period.

This increase is partially offset by re-purposing unallocated funds, as discussed further in Chapter 5G, section 5G.7.2. Unallocated funds have often been used to fund unanticipated maintenance needs during the year. Re-purposing unallocated funds to support an increase in the Power System maintenance budget will allow additional maintenance work to be proactively planned and prioritized. Unanticipated

[197] Sun Life Financial Canadian Benchmark for fiscal 2018.

maintenance requirements will be funded through re-allocations within the existing budget.

The planned budget increase for Power System maintenance reflects an aging and growing asset base, increased severe weather events, higher delivery costs, outstanding condition-based and corrective maintenance needs and additional regulatory and compliance requirements.

BC Hydro has mitigated these cost pressures through a number of improvements to grid intelligence and control, system automation, crew utilization and business processes as well as through strategic asset management and capital investment planning.

Table 5-17 below shows actual and planned maintenance costs by category. These costs are included in the KBU budgets in the Integrated Planning Business Group, discussed in Chapter 5A[198], but are consolidated below to provide an aggregate view.

198 As the fiscal 2019 forecast numbers pre-date the September 2018 re-organization, fiscal 2019 forecast maintenance costs are included in KBU budgets in both the Integrated Planning Business Group (Chapter 5A) and the Operations Business Group (Chapter 5C). The September 2018 re-organization centralized all maintenance budgets under the Integrated Planning Business Groups and is reflected starting in the fiscal 2020 plan. Further information is provided in Chapter 5C, section 5C.6.2.

Table 5-17 Maintenance Costs by Category[199, 200, 201, 202]

($ million)	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
	1	2	3	4	5	6	7	8
Maintenance								
Line Asset Maintenance	95.9	92.4	95.9	101.4	95.0	100.5	105.2	105.7
Stations Asset Maintenance	72.7	74.8	73.2	78.4	73.8	75.1	85.4	86.4
Distribution Emergency Response	31.4	31.0	31.4	33.0	31.4	30.6	42.5	42.9
Total Maintenance	200.0	198.3	200.5	212.8	200.2	206.1	233.1	235.0

Table 5-18 below shows the drivers of the budget increase from fiscal 2019 forecast to fiscal 2020 plan. The most significant cost driver is an uncontrollable increase to the rolling five-year average used to budget for storm restoration costs, which reflects increased storm damage in recent years.

Table 5-18 Maintenance Cost Increases (Fiscal 2019 Forecast to Fiscal 2020 Plan)

($ million)	Line Asset Maintenance	Stations Asset Maintenance	Distribution Emergency Response	Total
Storm Restoration Five Year Average [203]	0	0	11.1	11.1
Standard Labour Rate Increases [204]	2.5	1.3	0.8	4.6
Net Re-organization impacts [205]	0.3	3.2	0	3.5
Re-purposing of unallocated funds [206]	3.1	4.7	0	7.9
Total	4.7	10.3	11.9	27.0 [207]

199 Line Asset Maintenance is equivalent to the total fiscal 2019 forecast number shown on line 1 of Chapter 5A, Table 5A-10 (Line Asset Maintenance Department of the Line Asset Planning KBU).

200 Stations Asset Maintenance is included in the total fiscal 2019 forecast number shown on line 1of Chapter 5A, Table 5A-8 (Stations Asset Maintenance Department of the Stations Asset Planning KBU).

201 Distribution Emergency Response is included in the total fiscal 2019 forecast number shown on line 4 of Chapter 5C, Table 5C-6 (Trouble Line Field Operations and Operations Support Department of the Line Field Operations KBU).

202 Increases to Distribution Emergency Response maintenance are primarily due to an increase in the five-year average used to calculate storm restoration costs, as described in section 5.5.2.2.

203 Discussed further in section 5.5.2 above.

204 Discussed further in section 5.5.2 above.

205 These increases are cost neutral and are offset by reductions of $1.5 million to the Business Unit Support KBU (see Chapter 5C, section 5C.11.3) of the Operations Business Group and $2.0 million to the Engineering KBU (see Chapter 5A, section 5A.9.3).

206 Discussed further in Chapter 5G, section 5G.7.2.

207 Numbers may not add exactly due to rounding.

5.8.2 The Budget for Asset Maintenance Must Address Preventative, Condition-Based and Corrective Maintenance

When developing a budget for maintenance work, we must account for three broad categories of maintenance, which are summarized in Figure 5-19 below. All of these activities are essential for the Power System to function safely and reliably.

Figure 5-19 Maintenance Work Types

Preventative	Condition-Based	Corrective
• Inspections, testing, calibration, and condition assessments • Planned Work	• Prioritized work based on current condition • Repair or replace in-service assets • Planned Work	• In-service asset damage or failure • Emergent work

The Power System asset maintenance programs also include two additional work categories which are required for safe and reliable asset operation:

- **Facility Maintenance:** work required to maintain the facilities and properties associated with the Power System. This includes items such as roofs, roads, fences, landscaping and snow removal; and
- **Engineering Services:** engineering support required for equipment maintenance. This includes activities such as developing and updating maintenance standards as well as performing failure investigations or specialized inspections or testing.

5.8.3 Determining the Appropriate Maintenance Investment Level Requires Consideration of Many Factors

While the trigger for spending on corrective maintenance - a failure or an emergent issue – is generally intuitive, the timing and prioritization of preventative and condition-based maintenance considers a number of factors.

- **Timing of preventative maintenance:** The frequency and timing of preventative maintenance activities are determined by factors such as asset criticality, component age and current condition, component failure modes, failure costs, and the duration required for repairs in the case of failure. Preventive maintenance programs are also influenced by manufacturers' recommendations, regulatory requirements, engineering judgement, field experience, historical reviews, and industry practices. As a result, preventative maintenance requirements and frequencies are cyclical and can vary by asset, which means that preventative maintenance work is not uniform year over year.

- **Timing and prioritization of condition-based maintenance:** The majority of condition-based maintenance work consists of annually planned repairs or replacements of defective or damaged components of the system and occurs before equipment fails. Condition-based maintenance is triggered by the condition of equipment as determined by preventative maintenance inspections, tests, maintenance standards, manufacturer notices and/or operational readings or alarms. Condition-based maintenance is prioritized based on risk, considering factors such as asset criticality, component age and condition, and the consequence of failure. These considerations are analysed to determine when work should be undertaken or if the component condition should continue to be monitored.

5.8.4 BC Hydro Conducts Maintenance Activities on a Broad Range of Assets

BC Hydro's maintenance activities are categorized into line asset maintenance, stations asset maintenance and distribution emergency response. The following sub-sections provide a summary of actual and planned maintenance expenditures, by category. These planned expenditures are the result of the budgeting process that considers all of the factors identified above.

5.8.4.1 Line Asset Maintenance Expenditures

Table 5-19 Line Asset Maintenance Expenditures

($ million)	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
	1	2	3	4	5	6	7	8
Transmission Maintenance	39.5	35.5	39.5	36.3	38.8	36.1	37.3	37.4
Distribution Maintenance	46.5	45.2	46.5	43.9	46.3	46.9	48.6	48.9
Telecom Protection & Control Maintenance	9.9	11.8	9.9	21.2	10.0	17.5	19.3	19.4
Total Line Asset Maintenance	95.9	92.4	95.9	101.4	95.0	100.5	105.2	105.7

- **Transmission Maintenance:** Annual transmission maintenance expenditures are primarily made up of transmission line maintenance and transmission vegetation management:
  - Transmission line maintenance includes inspecting and assessing the transmission system, test and treat inspections of wood poles as well as performing planned and unplanned repairs. All transmission structures are inspected at least once a year; and
  - Transmission vegetation management is required to manage vegetation along transmission corridors so that the system is reliable and safe and so that BC Hydro is in compliance with regulatory requirements.
- **Distribution Maintenance:** Annual distribution maintenance expenditures are made up of distribution line maintenance, distribution vegetation management and distribution meter maintenance:
  - Distribution line maintenance includes inspections and repairs of the overhead and underground system, test and treat inspections of wood poles as well as inspections and repairs of distribution assets such as manholes, cables, reclosers and voltage regulators and switches;
  - Distribution vegetation management includes routine maintenance to prune trees growing in proximity to power lines to reduce outages and damage caused by trees falling onto the distribution system; and

- Distribution meter maintenance includes programs to sample and test meters and exchange failed and time-expired meters, so that BC Hydro is in compliance with the requirements of the *Electricity and Gas Inspection Act* and with Measurement Canada's sampling regulations.

- **Telecommunications Protection and Control Maintenance:** Protection and control assets protect energized transmission equipment from being damaged from unplanned electrical events. They also provide system stability and reliability during disturbances, assist with the control of energy flows throughout the electrical grid and provide information to control centres through an integrated telecommunications system. Also included in this category are maintenance expenditures related to smart metering infrastructure telecommunications. These assets are maintained through a combination of preventative, condition-based and corrective maintenance work.

5.8.4.2 Stations Asset Maintenance Expenditures

Table 5-20 Stations Asset Maintenance Expenditures

($ million)	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
	1	2	3	4	5	6	7	8
Generation Maintenance	49.9	51.9	50.4	52.9	51.0	52.7	58.0	58.6
Substations Maintenance	17.6	18.5	17.6	20.3	17.6	17.2	22.4	22.6
Non-Integrated Area Maintenance	5.2	4.4	5.2	5.2	5.2	5.2	5.1	5.2
Stations Asset Maintenance	72.7	74.8	73.2	78.4	73.8	75.1	85.4	86.4

- **Generation Maintenance:** BC Hydro's generation assets include 83 generating units at 30 hydroelectric generating facilities as well as 81 dams located at generating stations and at additional locations to provide water storage and water diversion functions. Generation assets also include three gas fired units at BC Hydro's two thermal generating stations and four synchronous condenser units at a dedicated synchronous condenser station. These assets are maintained through a combination of preventative, condition-based, corrective, and facility maintenance work;

- **Substations Maintenance:** BC Hydro has over 300 transmission and distribution substations across the province. Substations are maintained to minimize the lifecycle cost of the equipment, support safe and reliable operation, and mitigate environmental impacts. These assets are maintained through a combination of preventative, condition-based, corrective, and facility maintenance work; and
- **Non-Integrated Area Maintenance:** BC Hydro has 17 diesel generating stations and one hydroelectric generating station in areas not connected to the integrated electric system. Maintenance on these assets consists of routine, scheduled and corrective work.

5.8.4.3 Distribution Emergency Response Maintenance Expenditures

Table 5-21 Distribution Emergency Response Maintenance Expenditures

($ million)	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
	1	2	3	4	5	6	7	8
Routine Trouble	22.4	21.0	22.4	22.7	22.4	21.6	22.4	22.7
Storm	6.7	6.7	6.7	6.7	6.7	6.7	17.8	17.9
Damage to Plant	2.3	3.3	2.3	3.6	2.3	2.3	2.3	2.4
Total Distribution Emergency Response	31.4	31.0	31.4	33.0	31.4	30.6	42.5	42.9

- **Routine Trouble** refers to maintenance expenditures for day-to-day restoration of power outages.
- **Storm** refers to maintenance expenditures for events causing outages over a large geographic area, affecting a large number of customers or of extended duration. As discussed in section 5.5.2.2 above, BC Hydro continues to budget for storm restoration costs using a five-year average of normal weather years. In recent years, we have experienced higher levels of storm related damage, which has caused the five year average of storm restoration costs to increase. Variances between planned and actual storm restoration costs are deferred to

the Storm Restoration Costs Regulatory Account, which is discussed in Chapter 7, section 7.8.1.

- **Damage to Plant** refers to events where a third-party may be liable for the cost of system repairs. These costs are partially offset by miscellaneous revenues.

5.9 Operating Costs by Business Group and by KBU

In Chapters 5A through 5G, BC Hydro provides detailed support for the forecast operating costs, by Business Group.

In response to commentary from the BCUC about its comfort level with BC Hydro's operating cost budget, these chapters provide significantly more information than the Previous Application on the operating costs and FTEs for each of BC Hydro's six business groups and 39 KBUs. They provide the full cost picture rather than focusing only on incremental changes.

Figure 5-20 and Figure 5-21 below provide a summary of operating costs and FTEs by Business Group. Additional details are provided in Table 5-22 and Table 5-23.

When reviewing the summaries provided below, it is important to note the following:

- The Integrated Planning Business Group holds the budget for all maintenance work while the Operations Business Group holds the FTEs associated with all maintenance work and is responsible for executing this work;
- The Safety Business Group includes the Learning and Development KBU, which includes the FTEs related to apprentices and trainees, which are distributed throughout the organization; and
- The Site C Project has been included in the Other category. The project has FTEs but no operating costs as all project costs are charged to capital and to the Site C Regulatory Account.

Figure 5-20 Net Operating Costs by Business Group (Fiscal 2020) [208]

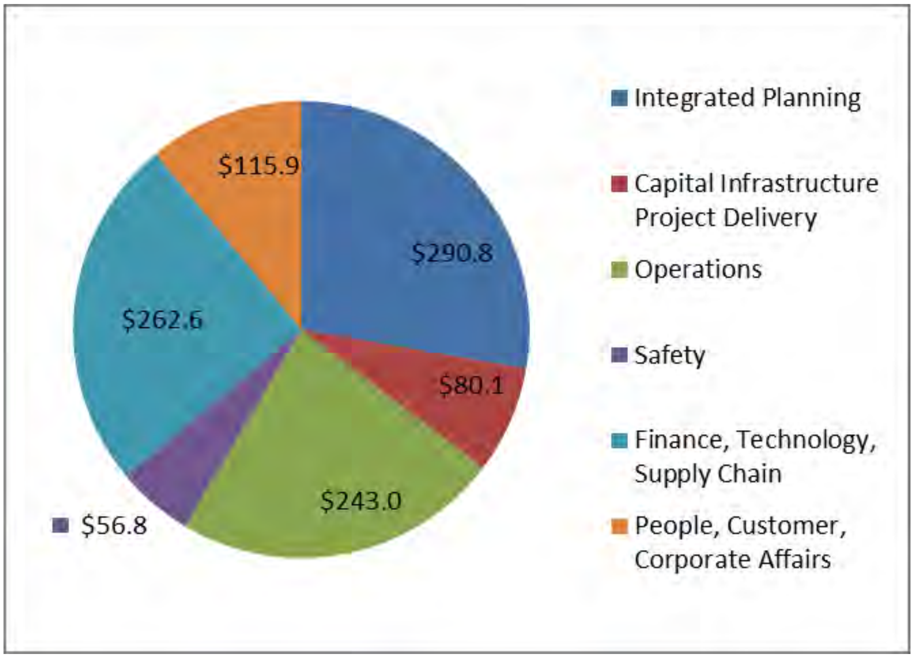
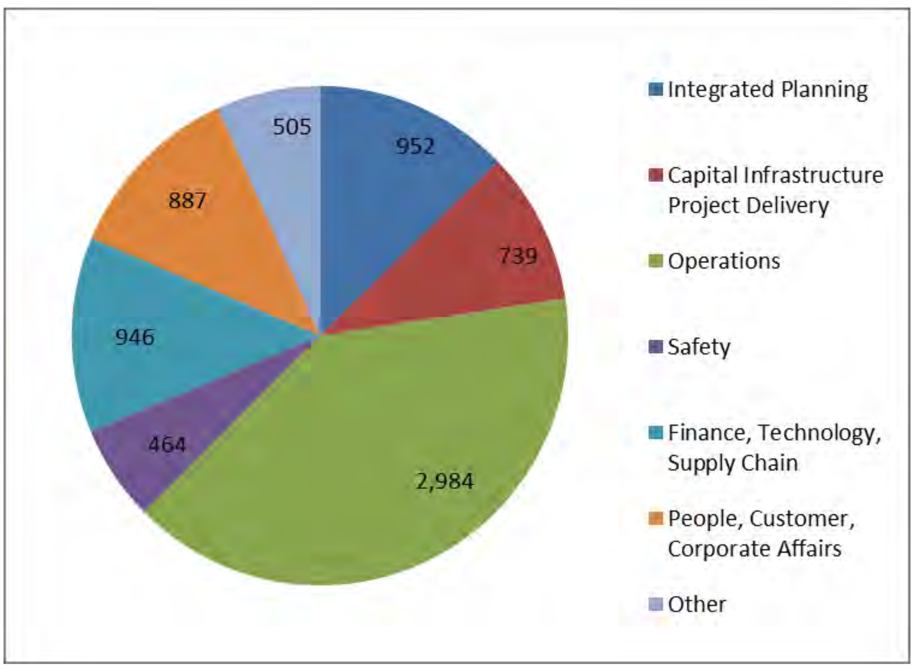


Figure 5-21 FTEs by Business Group (Fiscal 2020)



208 The Other category is not included in this figure because it includes a credit for capitalized costs which cannot be displayed correctly in a pie chart.

Table 5-22 Net Operating Costs by Business Group and by KBU

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
	Integrated Planning									
1	Energy Planning and Analytics	5.1 L1	6.5	5.7	6.2	5.9	6.3	6.8	7.9	8.4
2	Dam Safety	5.1 L2	8.8	8.4	8.9	8.6	9.0	10.0	10.2	10.3
5	Station Asset Planning	5.1 L3	102.7	102.8	105.4	108.0	106.2	94.0	97.0	98.1
3	Line Asset Planning	5.1 L4	111.3	107.0	112.0	114.3	111.3	121.4	127.2	128.1
6	Interconnections and Shared Assets	5.1 L5	9.0	10.3	9.1	8.8	9.2	9.2	10.5	10.6
4	Engineering	5.1 L6	19.9	19.2	20.2	20.5	20.5	21.8	24.7	25.1
7	Business Unit Support	5.1 L7	13.1	31.3	7.6	17.6	7.6	16.0	13.2	12.5
8	**Integrated Planning**	5.1 L14	271.3	284.8	269.4	283.8	270.1	279.3	290.8	293.0
	Capital Infrastructure Project Delivery									
9	Project Delivery	5.2 L1	13.4	12.7	14.2	13.5	14.3	13.9	14.0	14.5
10	Indigenous Relations	5.2 L2	6.1	7.3	6.1	6.1	6.1	6.3	6.1	6.3
11	Environment	5.2 L3	27.2	26.2	27.5	27.0	27.8	29.2	29.8	30.0
12	Properties	5.2 L4	32.2	32.2	32.5	32.7	32.8	32.7	29.3	29.5
13	Business Unit Support	5.2 L5	0.8	0.7	0.8	0.7	0.8	0.8	0.8	0.9
14	**Capital Infrastructure Project Delivery**	5.2 L12	79.7	79.2	81.1	79.9	81.9	82.9	80.1	81.1
	Operations									
15	Program and Contract Management	5.3 L1	13.8	11.6	14.1	11.9	14.3	12.8	14.0	14.2
16	Line Field Operations	5.3 L2	67.7	69.8	68.2	71.6	68.7	68.2	82.3	83.1
17	Stations Field Operations	5.3 L3	41.0	41.5	41.1	39.4	46.9	46.2	52.9	53.5
18	Distribution Design & Customer Connect	5.3 L4	12.8	10.2	13.1	10.6	13.5	14.3	14.8	15.1
19	Construction Services	5.3 L5	13.5	11.4	13.7	12.4	13.9	12.8	13.2	13.3
20	Generation System Operations	5.3 L6	14.5	16.0	14.7	14.2	14.8	14.6	15.0	15.2
21	T&D System Operations	5.3 L7	36.2	38.2	36.7	40.4	37.4	38.3	39.8	40.3
22	Business Unit Support	5.3 L8+L12	6.6	5.4	6.6	6.3	6.7	11.1	11.1	11.3
23	**Operations**	5.3 L15	206.1	204.2	208.2	206.7	216.2	218.4	243.0	246.0
	Safety									
24	Safety System and Assurance	5.4 L1	14.9	14.5	14.8	14.7	14.7	12.9	13.1	13.3
25	Learning and Development	5.4 L2	25.0	25.7	25.0	23.2	25.4	25.5	25.8	26.2
26	Field Safety Services	5.4 L3	4.9	5.7	5.0	5.7	5.1	6.2	6.6	6.7
27	Security and Emergency Management	5.4 L4	9.3	9.4	9.3	9.2	9.3	9.6	10.7	10.8
28	Business Unit Support	5.4 L5	0.5	0.6	0.5	0.6	0.5	0.6	0.6	0.6
29	**Safety**	5.4 L12	54.6	55.9	54.6	53.3	54.9	54.8	56.8	57.5
	Finance, Technology, Supply Chain									
30	Finance	5.5 L1	29.7	28.7	30.2	28.7	30.7	30.8	31.6	32.1
31	Technology	5.5 L2	141.1	134.5	141.3	128.3	140.5	133.7	135.8	136.4
32	Supply Chain	5.5 L3	91.8	89.9	92.2	89.0	93.0	93.3	94.5	95.5
33	Business Unit Support	5.5 L4	0.8	0.7	0.8	0.7	0.8	0.8	0.8	0.8
34	**Finance, Technology, Supply Chain**	5.5 L11	263.3	253.8	264.4	246.7	265.0	258.5	262.6	264.8
	People, Customer, Corporate Affairs									
35	Human Resources	5.6 L1	22.9	21.6	23.1	22.1	23.3	21.1	21.1	21.4
36	Customer Service	5.6 L2+L13	76.2	68.9	73.6	68.7	73.8	69.0	68.4	69.1
37	Conservation and Energy Management	5.6 L3	0.6	0.6	0.6	0.5	0.6	0.6	0.6	0.6
38	Power Acquisitions and Contract Management	5.6 L4	4.6	4.6	4.7	4.9	4.8	4.8	4.7	4.7
39	Communications and Community Engagement	5.6 L5	12.8	12.4	12.6	13.7	12.7	13.6	12.9	13.0
40	Regulatory and Rates	5.6 L6	6.0	5.8	6.1	5.4	6.2	6.2	6.3	6.4
41	Ethics and Merit Office	5.6 L7	0.4	0.5	0.4	0.6	0.4	0.8	1.0	1.0
42	Business Unit Support	5.6 L8	0.7	0.8	0.8	0.7	0.8	0.8	0.8	0.8
43	**People, Customer, Corporate Affairs**	5.6 L15	124.3	115.2	121.8	116.8	122.5	116.9	115.9	117.2
	Other									
44	Office of the General Counsel	5.7 L1	12.2	11.1	12.3	10.6	12.3	12.2	11.7	11.8
45	Office of the President and Chief Operating Officer	5.7 L2	0.9	1.0	1.0	0.8	1.0	0.8	0.9	0.9
46	Site C Project	5.7 L3	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0
47	Independent Power Producers Capital Leases	5.7 L8	28.2	28.2	63.6	63.6	54.3	54.3	0.0	0.0
48	Corporate Costs	5.7 L4	17.2	13.1	18.4	28.4	19.7	38.9	13.0	13.0
49	Capitalized Costs	5.7 L5+L7	(180.2)	(179.0)	(158.6)	(158.6)	(136.9)	(137.6)	(115.8)	(93.8)
50	**Other**	5.7 L12	(121.7)	(125.6)	(63.4)	(55.2)	(49.6)	(31.4)	(90.2)	(68.1)
51	F17-F19 RRA Adjustment	5.0 L8	10.1	0.0	10.2	0.0	10.4	0.0	0.0	0.0
52	Total BC Hydro Net Operating Costs	5.0 L15	887.7	867.6	946.3	931.9	971.5	979.3	959.0	991.4

Table 5-23 FTEs by Business Group and by KBU

	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
		1	2	3	4	5	6	7	8
Integrated Planning									
Energy Planning and Analytics	16.0 L1	27	29	27	31	27	38	44	44
Dam Safety	16.0 L2	35	34	35	34	35	37	37	37
Station Asset Planning	16.0 L3	51	51	51	49	51	46	59	59
Line Asset Planning	16.0 L4	109	109	109	112	109	113	116	116
Interconnections and Shared Assets	16.0 L5	40	36	40	43	40	47	47	47
Engineering	16.0 L6	536	540	536	558	536	586	646	646
Business Unit Support	16.0 L7	4	4	4	3	4	3	3	3
Integrated Planning	16.0 L8	802	804	802	830	802	870	952	952
Capital Infrastructure Project Delivery									
Project Delivery	16.0 L9	340	324	368	387	368	453	450	450
Indigenous Relations	16.0 L10	47	57	47	59	47	69	69	69
Environment	16.0 L11	83	86	83	90	83	89	94	94
Properties	16.0 L12	106	110	106	114	106	124	123	123
Business Unit Support	16.0 L13	3	3	3	3	3	3	3	3
Capital Infrastructure Project Delivery	16.0 L14	579	581	607	652	607	737	739	739
Operations									
Program and Contract Management	16.0 L15	213	205	217	206	217	221	228	228
Line Field Operations	16.0 L16	844	838	844	856	844	931	938	938
Stations Field Operations	16.0 L17	856	829	856	818	856	858	777	777
Distribution Design & Customer Connect	16.0 L18	338	325	338	347	338	379	379	379
Construction Services	16.0 L19	404	411	404	409	404	398	397	397
Generation System Operations	16.0 L20	64	65	64	68	64	64	63	63
T&D System Operations	16.0 L21	165	170	165	174	165	178	197	197
Business Unit Support	16.0 L22	3	3	3	3	3	3	5	5
Operations	16.0 L23	2,889	2,845	2,893	2,880	2,893	3,033	2,984	2,984
Safety									
Safety System and Assurance	16.0 L24	52	48	52	49	52	52	52	52
Learning and Development	16.0 L25	438	456	438	437	438	358	317	300
Field Safety Services	16.0 L26	53	50	55	56	55	63	62	62
Security and Emergency Management	16.0 L27	18	20	18	25	18	26	31	31
Business Unit Support	16.0 L28	2	2	2	2	2	2	2	2
Safety	16.0 L29	563	576	565	568	565	501	464	447
Finance, Technology, Supply Chain									
Finance	16.0 L30	188	194	188	196	188	204	206	206
Technology	16.0 L31	176	186	191	226	202	263	269	269
Supply Chain	16.0 L32	402	421	402	447	402	454	468	468
Business Unit Support	16.0 L33	3	3	3	3	3	3	3	3
Finance, Technology, Supply Chain	16.0 L34	769	805	784	871	795	924	946	946
People, Customer, Corporate Affairs									
Human Resources	16.0 L35	88	84	88	88	88	125	124	124
Customer Service	16.0 L36	124	154	124	191	124	495	479	479
Conservation and Energy Management	16.0 L37	114	110	112	112	112	116	116	116
Power Acquisitions and Contract Management	16.0 L38	23	26	23	28	23	27	26	26
Communications and Community Engagement	16.0 L39	86	94	86	95	86	107	107	107
Regulatory and Rates	16.0 L40	28	23	27	26	27	28	28	28
Ethics and Merit Office	16.0 L41	1	2	1	3	1	4	5	5
Business Unit Support	16.0 L43	3	3	3	3	3	3	3	3
People, Customer, Corporate Affairs	16.0 L44	467	497	463	545	463	906	887	887
Other									
Office of the General Counsel	16.0 L45	37	36	37	35	37	43	42	42
Office of the President and Chief Operating Officer	16.0 L46	4	4	4	3	4	3	3	3
Site C Project	16.0 L47	186	167	189	226	199	389	460	472
Independent Power Producer Capital Leases	16.0 L48	0	0	0	0	0	0	0	0
Corporate Costs	16.0 L49	0	0	0	0	0	0	0	0
Capitalized Costs	16.0 L50	0	0	0	0	0	0	0	0
Other	16.0 L51	227	208	231	264	241	434	505	516
Total BC Hydro FTEs	16.0 L60	6,296	6,315	6,344	6,611	6,365	7,405	7,477	7,471

BC Hydro
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Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Chapter 5A

Operating Costs
Integrated Planning Business Group

PLAN

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5A.1 Introduction – Integrated Planning Business Group

Chapter 5A provides and explains in detail the composition of, and rationale for the operating costs of the Integrated Planning Business Group. The Integrated Planning Business Group is one of six business groups in the organization and is responsible for planning BC Hydro's Power System. It serves as the Plan function of the Plan-Build-Operate-Support model.

The Integrated Planning Business Group budget was developed as part of the budgeting process outlined in Chapter 5, section 5.4. The information provided in this Chapter 5A demonstrates the basis for the entirety of the Business Group and KBU budgets, rather than focussing only on incremental cost requirements.

Chapter 5A is organized as follows:

- Section 5A.2 provides an overview of the organization and responsibilities of the Integrated Planning Business Group;
- Section 5A.3 provides the operating costs and FTE information for the Integrated Planning Business Group as a whole[209];
- Sections 5A.4 to 5A.10 provide more detailed information on the responsibilities, cost and FTEs for each KBU within the Integrated Planning Business Group. The operating costs and FTE information for each KBU is broken out into two sections:[209]
  - Overview of Operating Costs and FTEs – This chapter explains the starting operating costs and FTEs based on the fiscal 2019 forecast; and
  - Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs – This chapter explains any incremental changes between fiscal 2019 forecast and fiscal 2020 and fiscal 2021 plan.

[209] Please note the amounts presented in the tables in these sections may not add due to rounding.

5A.2 Overview of Integrated Planning Business Group Organization and Responsibilities

The Integrated Planning Business Group brings together our main planning, asset management and engineering functions to plan and design a safe, efficient and reliable system that drives the most value from our investments, and meets the needs of our customers.

More specifically, Integrated Planning is responsible for:

- Developing the load forecast and the Integrated Resource Plan;
- Determining when and where to invest in our system;
- Governing the safe management of reservoir containment and water conveyance;
- Producing the Capital Plan and fulfilling the role of project initiator;
- Managing customer requests to interconnect, supply, or receive electrical services from our system; and
- Providing engineering services to the organization.

The Integrated Planning Business Group was created subsequent to the filing of the Previous Application. The planning functions of the former Transmission and Distribution and Generation Business Groups are now combined into the Integrated Planning Business Group.

The Integrated Planning Business Group consists of the following KBUs:

Business Group	Key Business Unit
Integrated Planning	Energy Planning and Analytics Dam Safety Stations Asset Planning Line Asset Planning Interconnections and Shared Assets Engineering Business Unit Support

5A.3 Fiscal 2020 and Fiscal 2021 Plan Operating Cost and FTE Summaries

This section addresses planned operating costs and FTEs for the Integrated Planning Business Group. The following are some key points of note with respect to the information provided in Figure 5A-1, Table 5A-1 and Figure 5A-2, Table 5A-2 and Table 5A-3:

- Approximately $190 million or 66 per cent of the operating costs for Integrated Planning Business Group are directly attributable to power system maintenance programs. The majority of this work is performed by internal workers;
- Over 67 per cent of the FTEs in this Business Group are represented by the Engineering KBU. Over 75 per cent of the labour costs for these FTEs are not included in the operating costs budget as these costs are charged primarily to capital projects; and
- Operating costs are increasing in the Integrated Planning Business Group, primarily due to increased Power System maintenance expenditures (as discussed in Chapter 5, section 5.8) and Standard Labour Rate increases (as discussed in Chapter 5, section 5.5.2).

Planned operating costs for the Integrated Planning Business Group are approximately $290.8 million in fiscal 2020 and approximately $293.0 million in fiscal 2021. The operating costs for the Integrated Planning Business Group are summarized by KBU in Figure 5A-1. Additional cost details are provided in Table 5A-1 below.

Figure 5A-1 Integrated Planning Net Operating Costs by KBU (Fiscal 2020 Plan) ($ million)

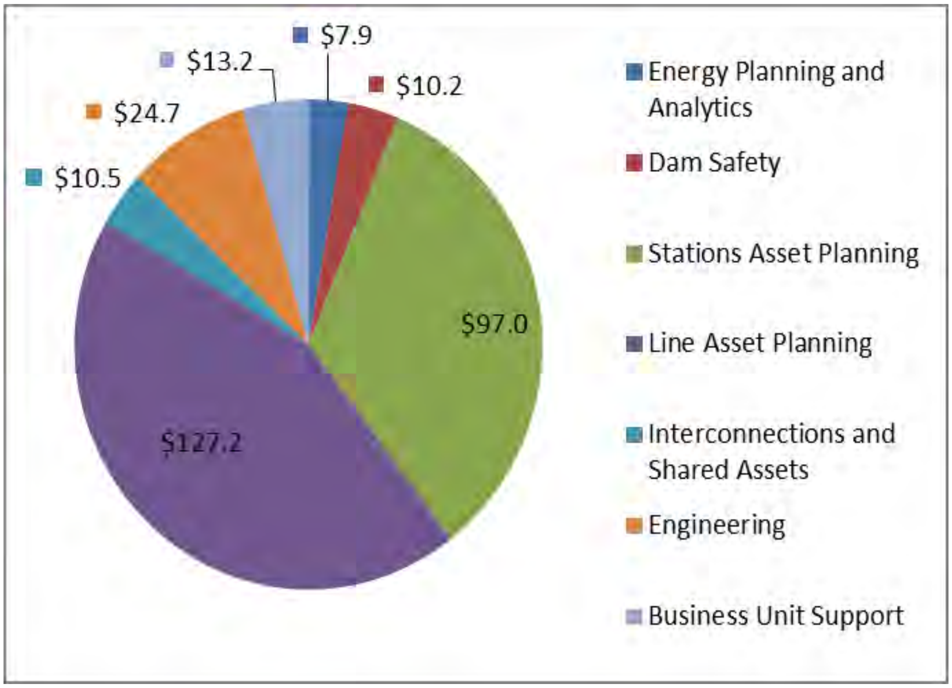


Table 5A-1 Integrated Planning Net Operating Costs by KBU

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Energy Planning and Analytics	5.1 L1	6.5	5.7	6.2	5.9	6.3	6.8	7.9	8.4
2	Dam Safety	5.1 L2	8.8	8.4	8.9	8.6	9.0	10.0	10.2	10.3
5	Station Asset Planning	5.1 L3	102.7	102.8	105.4	108.0	106.2	94.0	97.0	98.1
3	Line Asset Planning	5.1 L4	111.3	107.0	112.0	114.3	111.3	121.4	127.2	128.1
6	Interconnections and Shared Assets	5.1 L5	9.0	10.3	9.1	8.8	9.2	9.2	10.5	10.6
4	Engineering	5.1 L6	19.9	19.2	20.2	20.5	20.5	21.8	24.7	25.1
7	Business Unit Support	5.1 L7	13.1	31.3	7.6	17.6	7.6	16.0	13.2	12.5
8	Total	5.1 L14	271.3	284.8	269.4	283.8	270.1	279.3	290.8	293.0

The FTEs for the Integrated Planning Business Group are summarized by KBU in Figure 5A-2. Additional details are provided in Table 5A-2 below.

Figure 5A-2 Integrated Planning FTEs by KBU (Fiscal 2020 Plan)

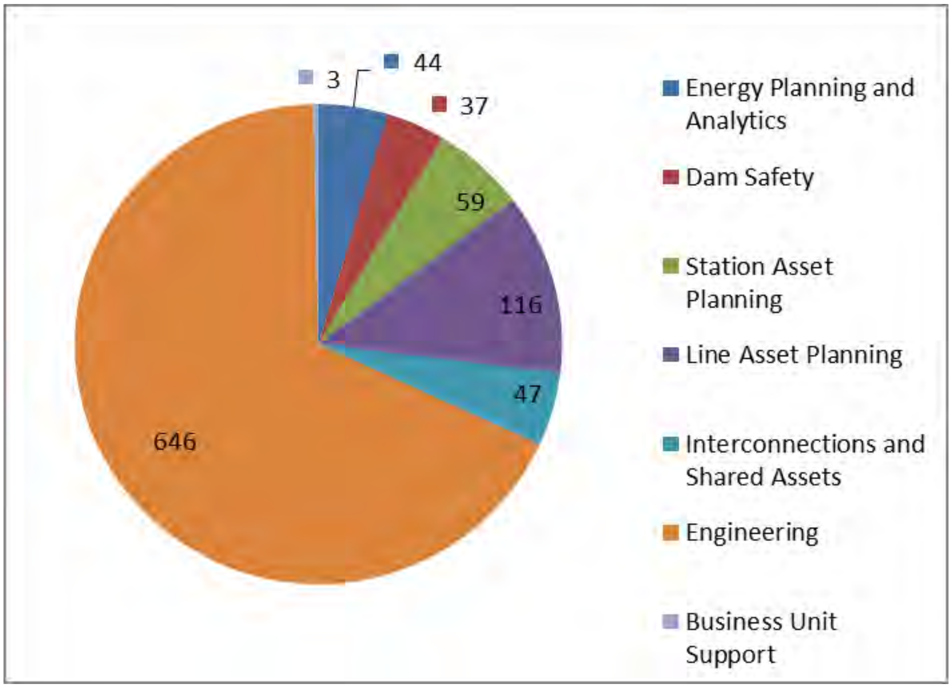


Table 5A-2 Integrated Planning FTEs by KBU

	(FTEs)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Energy Planning and Analytics	16.0 L1	27	29	27	31	27	38	44	44
2	Dam Safety	16.0 L2	35	34	35	34	35	37	37	37
5	Station Asset Planning	16.0 L3	51	51	51	49	51	46	59	59
3	Line Asset Planning	16.0 L4	109	109	109	112	109	113	116	116
6	Interconnections and Shared Assets	16.0 L5	40	36	40	43	40	47	47	47
4	Engineering	16.0 L6	536	540	536	558	536	586	646	646
7	Business Unit Support	16.0 L7	4	4	4	3	4	3	3	3
8	Total	16.0 L8	802	804	802	830	802	870	952	952

Table 5A-3 below provides a continuity table which highlights changes to the Integrated Planning Business Group from the Previous Application. An overall discussion of these changes, at a company-wide level, is provided in Chapter 5, section 5.5.2. Further details, by KBU, are provided in the sections below.

Table 5A-3 Integrated Planning Operating Costs Continuity Schedule

	($ million)		F2020 Plan	F2021 Plan
1	F2019 Revenue Requirement Application Plan (Training, Development and Generation)		146.2	
2	Reorganization Impacts		123.9	
3	F2019 Revenue Requirement Application Plan (Integrated Planning)		270.1	
4	Budget Transfers Between Business Groups		9.2	
5	F2019 Revenue Requirement Application Forecast (Integrated Planning) / carry forward plan (Schedule 5.1, line 14)	A	279.3	290.8
6	Current Year Budget Transfers Between Business Groups	B	5.7	(0.5)
7	Test Period Savings			
8	Lease standard impact reclassification		(0.3)	
9	Vacancy factor savings		(1.2)	
10		C	(1.5)	-
11	Test Period Cost Increases			
12	Labour		7.3	2.7
13		D	7.3	2.7
14	Test Period Net Increase/(Decrease)	E=C+D	5.8	2.7
15	Net Operating Costs (Schedule 5.1, line 14)	A+B+E	290.8	293.0

5A.4 Energy Planning and Analytics KBU

5A.4.1 Responsibilities

The Energy Planning and Analytics KBU is responsible for the development of BC Hydro’s energy plans, the delivery of integrated planning and analytics services, and the prioritization of investments within BC Hydro’s capital and maintenance plans.

This KBU was created subsequent to the filing of the Previous Application. It combines the Reliability and Performance Assessment and Portfolio Optimization and Management departments, previously part of the former Asset Management and Distribution Engineering KBU, with the Energy Planning department, previously part of the Corporate Affairs KBU.

The Energy Planning and Analytics KBU is comprised of the following two departments:

- Energy Planning Department; and
- Reliability and Performance Assessment Department.

5A.4.1.1. Energy Planning Department

The Energy Planning department consists of five teams:

- Resource Planning Team - Integrated Resource Planning;
- Resource Planning Team - Modelling;
- Load Forecasting;
- Network Integration; and
- Portfolio Optimization and Management.

The two Resource Planning teams facilitate the development of BC Hydro's long-term resource strategy as well as short-term actions to respond to provincial energy policy objectives and to support customer reliability. The teams are responsible for BC Hydro's Integrated Resource Plan (**IRP**) and for engagement with the public and First Nations on the development of the IRP. These teams undertake analysis to identify the need and timing for new generation and transmission resources on the integrated system as well as cost-effective options to meet those needs. These teams also conduct system contingency analysis, scenario planning, and structured evaluation of high-level alternatives to manage the uncertainties that are inherent in long-term planning. In addition, these teams are responsible for maintaining BC Hydro's resource options database and developing the Long Run Marginal Cost and Reference Price indices, as well as providing support to regulatory applications and business decisions related to these areas.

The Load Forecasting team produces a 20-year forecast for energy and peak load as well as a five-year forecast on an annual cycle. The five-year load forecast is an important input to the Revenue Requirements Application, while the 20-year load forecast is important for capital planning and long-term resource planning. BC Hydro's five-year load forecast is discussed in Chapter 3.

Transmission service requests define BC Hydro's domestic transmission capacity requirements. The Network Integration team manages the development and submission of transmission service requests to the Market Policy and Operations department in the T&D System Operations KBU. This team also represents BC Hydro's transmission interests as a transmission customer at the Western Electricity Coordinating Council (**WECC**). In addition, the team is responsible for integrated resource planning for the Fort Nelson area. The Fort Nelson area is not connected to BC Hydro's integrated system, but is grid connected to local generation resources and to Alberta's grid through a radial transmission line.

The Portfolio Optimization and Management team coordinates the annual capital planning process for all Integrated Planning investments and leads the integration of Stations, Line, Interconnection and Dam Safety investments into a cohesive portfolio of projects and programs. This includes the prioritization of investments within BC Hydro's overall capital portfolio, and aligning the overall capital plan with BC Hydro's strategic direction and objectives within available financial and labour resources. BC Hydro's capital plan is discussed in Chapter 6.

5A.4.1.2. Reliability and Performance Assessment Department

The Reliability and Performance Assessment department provides Asset Health and Reliability reporting and analytics to the Lines Asset Planning and Stations Asset Planning KBUs to support customer reliability. The department is responsible for the sustainment of an asset registry of over 4 million BC Hydro assets, as well as the accompanying business applications and analytics to enable data-driven operational and management decision making. In addition, this team works with asset management business groups to ensure the asset data is current and consistent with business requirements, which includes setting up preventative maintenance work orders and ensuring they are completed in compliance with maintenance standards.

5A.4.2 Overview of Operating Costs and FTEs

Table 5A-4 Energy Planning and Analytics KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Energy Planning	4.3	0.0	0.6	0.2	0.2	0.0	0.0	**5.2**	26
2	Reliability and Performance Assessment	1.5	0.0	0.2	0.0	0.0	0.0	0.0	**1.7**	12
3	**Total (Sch 5.1 L1, Sch 16.0 L1)**	**5.8**	**0.0**	**0.7**	**0.2**	**0.2**	**0.0**	**0.0**	**6.8**	**38**

5A.4.2.1. Energy Planning Department

Since fiscal 2016, the overall operating budget for the Energy Planning department has remained constant despite the increased complexity of the planning environment. For example, BC Hydro’s 20-year load forecast must build detailed models of reliable predictors of future sales such as GDP or industrial activity. In recent years, the relationship between these predictors and energy sales at a point in time appears to be changing, requiring more detailed analysis and investigation. In addition, resource planners must now take into account the potential for emerging supply technologies such as solar generation or battery storage, which will impact the way energy is produced in future. All of this activity drives an increased demand for load forecasting and resource planning analysis.

Approximately 83 per cent of the Energy Planning department budget is related to labour and represents 26 FTEs as follows:

- Two FTEs representing the Director of Energy Planning and Analytics and an Administrative Assistant;
- Six FTEs on the Load Forecasting team. In fiscal 2018, an internal audit of BC Hydro’s Load Forecasting function recommended that “additional staff members should be considered to assist with the preparation of forecasts for the industrial class sectors, analysis of high volume of data, preparation of documents for regulatory hearings, and to minimize employee succession

risk”[210]. To advance this recommendation, one FTE was transferred from the Network Integration team and one additional FTE will be added to the team in fiscal 2020;

- Three FTEs on the Network Integration team;
- Seven FTEs on the Resource Planning team for integrated resource planning. Since the last Integrated Resource Plan in 2013, this group has produced analyses of regional load-resource balances, reference prices and resource options to support a range of business decisions and regulatory proceedings. Examples include analysis related to the Site C Inquiry, Electricity Purchase Agreement renewal applications, regional supply plans, and the design of new rate structures;
- Three FTEs on the Resource Planning team execute up to 250 system portfolio modelling runs per year to inform internal business decisions and regulatory proceedings, while supporting resource planning initiatives in partnership with stakeholders such as the City of Vancouver, the Government of B.C. and the Government of Canada; and
- Five FTEs in the Portfolio Optimization and Management department are responsible for coordinating the annual capital planning process for the Power System portfolio including the prioritization of more than 1,400 discrete investments and managing in-year adjustments to a capital portfolio which was forecasted at approximately $1.4 billion in fiscal 2019. BC Hydro must be flexible and responsive to the investment needs of the system. As part of the annual capital planning cycle, more than 50 per cent of the investments within the capital portfolio require detailed review, revision and prioritization so that the Capital Plan is updated and prioritized to respond to the latest information on the system risks and needs.

[210] See Appendix P, BC Hydro Load Forecast Audit.

The $0.6 million in Services expenditures for this department are primarily related to professional consulting services to inform the development of BC Hydro's load forecasts. The $0.2 million in Materials expenditures are for subscriptions to research services, also to inform the development of load forecasts. The $0.2 million in Buildings and Equipment expenditures are primarily related to subscriptions for capacity expansion and market price forecast modelling software.

5A.4.2.2. Reliability and Performance Assessment Department

This department consists of 12 FTEs who are responsible for:

- Maintaining asset registry records for over 4 million BC Hydro assets;
- Processing approximately 80,000 work orders annually;
- Creating and modifying asset management programs in response to updates or additions to a library of over 20,000 maintenance standards; and
- Providing support for NERC compliance for thousands of assets critical to the BC Hydro system.

The $0.2 million in Services expenditures for this department are primarily related to Information Technology contractors and research memberships that support ongoing efforts to automate the setting up and processing of maintenance work orders that are currently processed manually.

5A.4.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5A-5 Energy Planning and Analytics KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.1 L1	6.5	5.7	6.2	5.9	6.3	6.8	7.9	8.4
2	FTEs	16.0 L1	27	29	27	31	27	38	44	44

Operating costs are increasing by approximately $1.1 million from fiscal 2019 forecast to fiscal 2020 plan due to:

- Standard Labour Rate increases;
- The transfer of four FTEs from the Stations Field Operations KBU and one FTE from the Project Delivery KBU;
- The addition of one FTE to support NERC CIPv5 compliance, as discussed in Chapter 5C, section 5C.10.3; and
- The addition of one FTE on the Load Forecasting team to respond to the internal audit recommendation, as discussed above.

Operating costs are increasing by approximately $0.5 million from fiscal 2020 plan to fiscal 2021 plan due to Standard Labour Rate increases as well as $0.3 million in additional one-time funding for the development of the 2021 IRP, which is being provided through a transfer from the Business Support KBU of the Integrated Planning Business Group.

The increase in FTEs from fiscal 2019 RRA to fiscal 2019 forecast primarily reflects the addition of the Portfolio Optimization and Management team to the Energy Planning department.

5A.5 Dam Safety KBU

5A.5.1 Responsibilities

The primary function of the Dam Safety KBU is to administer and implement BC Hydro's Dam Safety Program.

BC Hydro currently owns, operates, and maintains 81 dams at 41 sites throughout B.C. as a major part of our generating system. As a dam owner, BC Hydro is accountable to the Government of B.C. for overseeing the safety of BC Hydro dams in accordance with the British Columbia Dam Safety Regulation. BC Hydro representatives communicate regularly with the Comptroller of Water Rights, who represents the Government of B.C. on dam safety matters.

Through our Dam Safety Program, BC Hydro manages the risks associated with our dams, reservoirs and water passages to protect against any impacts from their misoperation or failure and to support continued reliability of electricity supply.

There have been no material changes to the Dam Safety KBU since the Previous Application.

The Dam Safety KBU includes the following departments:

- Regulatory and Risk Management Department;
- Asset Management Department; and
- Surveillance Department.

5A.5.1.1. Regulatory and Risk Management Department

The Regulatory and Risk Management department is responsible for establishing the dam safety governance framework, overseeing compliance with the requirements of the Dam Safety Regulation as well as documenting, tracking, rating and reporting all dam safety issues. Key activities in the department include:

- Developing strategies and objectives for dam safety risk reduction;
- Communicating with the Comptroller of Water Rights to confirm compliance with the Dam Safety Regulation;
- Developing, reviewing and updating expectations and procedures in the Dam Safety Program Governance and Implementation Manuals;
- Managing the Dam Safety Reviews, including scheduling of reviews in accordance with the requirements of the Dam Safety Regulation, procuring and assigning independent external reviewers, compiling background reference

documents and drawings for the reference of the reviewers, and coordinating the production and distribution of the Dam Safety Review reports;

- Updating the Operation, Maintenance and Surveillance Manuals for all of BC Hydro's dams in accordance with the Dam Safety Regulation;
- Overseeing the assignment of risk ratings to the issues documented and tracked in the Dam Safety issues database; and
- Providing oversight and audits for dam safety gate and water conveyance-related matters.

5A.5.1.2. Asset Management Department

The Asset Management department is responsible for the prioritization, initiation, implementation and management of the Dam Safety Investigations Program and the Dam Safety Capital Plan. Key activities in the department include:

- Managing the Dam Safety Investigations Program, including the development of prioritized short-term and long-term plans for Dam Safety investigations based on risk level as well as initiating the Investigations, developing and approving the Investigations' scope, and providing oversight of Investigations until completion and acceptance;
- Developing and updating the Dam Safety component of BC Hydro's Capital Plan so that Dam Safety risk reduction targets are achieved and are aligned with other asset management strategies;
- Initiating capital projects, including approving the project scope, and providing oversight of the project risk reduction objectives until completion and acceptance; and
- Updating the Dam Safety issues database to reflect findings from the Dam Safety Investigations and risk reductions achieved by capital projects.

5A.5.1.3. Surveillance Department

The Surveillance department is responsible for performing or overseeing all dam safety related activities at the dams and reservoirs including inspections, instrumentation monitoring and maintenance, and reporting of any unusual conditions. Key activities in the department include:

- Conducting and documenting the semi-annual and annual inspections of the dams and reservoir slopes;
- Reviewing the results of weekly and monthly dam safety inspections completed by site operations staff;
- Providing dam safety training for site operations staff;
- Conducting increased or enhanced surveillance in response to unusual conditions at dams, such as during floods or other high reservoir events;
- Monitoring and collecting data from the various dams' performance monitoring instrumentation and ensuring the quality and integrity of the data;
- Establishing warning and alarm thresholds for all instrumentation;
- Identifying unusual observations, conditions, or instrumentation readings and documenting them in the Dam Safety issues database as required;
- Overseeing the implementation and approval of Interim Dam Safety Risk Management Plans in response to circumstances where construction or maintenance activities have potential to damage the dam or impede critical functions, or where risks that are above established targets must be retained until upgrades have been completed;
- Liaising with site management employees in the Operations Business Group to provide information on current dam safety issues and to arrange for required support from the Operations Business Group for routine weekly and monthly inspections;

- Participating in and providing input to Emergency Preparedness exercises; and
- Staffing the Dam Safety on-call process to provide 24/7 coverage of alarms and other dam safety related matters.

5A.5.2 Overview of Operating Costs and FTEs

Table 5A-6 Dam Safety KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Regulatory and Risk Management	1.5	0.0	1.0	0.0	0.0	0.0	0.0	**2.5**	8
2	Asset Management	1.5	0.0	2.0	0.0	0.0	0.0	0.0	**3.5**	4
3	Surveillance	3.2	0.0	0.6	0.1	0.0	0.0	0.0	**4.0**	25
4	**Total (Sch 5.1 L2, Sch 16.0 L2)**	**6.2**	**0.0**	**3.6**	**0.1**	**0.0**	**0.0**	**0.0**	**10.0**	**37**

The Dam Safety KBU is resourced to the level required to administer and implement the Dam Safety Program in accordance with accepted Canadian and international practices.

No two dam owners organize and delegate responsibilities relating to their dam safety programs in the same manner, nor do any two dam owners hold the same level of risk and complexity within their fleets of dams. As a result, direct comparisons of costs and assigned workforces on dam safety are difficult, if not impossible, to make. Therefore, BC Hydro considers assessments and audits of the Program’s performance to be the best means available to demonstrate whether staffing and monetary resources assigned to the Dam Safety KBU are sufficient and appropriate.

Since fiscal 2017, BC Hydro has conducted an internal audit as well as an internal review of its Dam Safety Program. BC Hydro believes that these assessments demonstrate that the staffing and monetary resources assigned to the Dam Safety KBU are sufficient and appropriate:

- The Dam Safety Program is audited every five years. The most recent audit was completed in September 2018 and was conducted by a team that included international subject matter experts in dam safety management and hazardous process industries. The audit found that "BC Hydro has a well-established Dam Safety Program that is in line with international practices with some aspects operating at best practice levels." The audit also included recommendations for improvements to some aspects of the Program where issues and opportunities for improvement had been identified; and

- Similar findings resulted from a self-assessment performed by the Dam Safety KBU in 2017 to 2018, using a methodology that was developed by the Dam Safety Interest Group of CEATI International and is being used by a number of dam owners from across North America. This assessment was facilitated by an international dam safety consulting firm that is familiar with the methodology, and assessed levels were supported by evidence and documentation to the satisfaction of the facilitator.

5A.5.2.1. Regulatory and Risk Management Department

The majority of this department's budget is related to labour costs for eight FTEs.

The department's Services budget includes $0.7 million to procure engineering services required to comply with the British Columbia Dam Safety Regulation. The department engages consultants to perform independent Dam Safety Reviews of, on average, five different dam sites each year. It also makes occasional use of contractors to supplement internal staff in preparing major updates to various dams' Operations, Maintenance and Surveillance Manuals, again at an average rate of five per year.

The remaining $0.3 million of Services procured by this department is for outreach and development activities to improve BC Hydro's Dam Safety Program, reinforce best practices, and influence the development of industry practices so that BC Hydro's Dam Safety Program remains relevant and adaptable to changing conditions.

5A.5.2.2. Asset Management Department

The Asset Management department consists of four FTEs. These FTEs account for approximately $0.6 million of the total $1.5 million of labour costs in this department and are responsible for:

- Planning, managing and overseeing a program of investigations to identify deficiencies and issues and their means of remediation. BC Hydro tracks approximately 250 deficiencies and 1,000 other ongoing issues each year; and
- Planning, initiating and overseeing capital projects to remediate identified deficiencies. At any given time, BC Hydro typically has more than 20 active Dam Safety projects.

The remaining $0.9 million in labour costs for this department and the $2.0 million in Services represent costs expended by other BC Hydro KBUs (e.g., Engineering and Construction Services), engineering consultants and contractors to perform Dam Safety investigations. The balance between the use of internal and external resources is based on resource availability and the need for specific expertise, varying slightly from year-to-year depending on the investment requirements.

5A.5.2.3. Surveillance Department

The majority of this department's budget is related to labour costs for 25 FTEs, primarily made up of instrumentation technologists and dam safety engineers. This department's labour costs also include:

- Approximately $0.2 million in overtime for staffing the Dam Safety on-call process to provide 24/7 coverage and adequate response to alarms on key dam performance monitoring instruments and to address other dam safety related matters; and
- Approximately $0.3 million for work performed by other KBUs in BC Hydro such as surveying.

This department's services budget includes approximately $0.6 million to support the surveillance component of the Dam Safety Program. This is primarily related to helicopter services for dam and reservoir slopes inspections and surveying by external contractors.

This department's materials budget provides funding for the repair and maintenance of the performance monitoring instrumentation and data acquisition systems.

5A.5.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5A-7 Dam Safety KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.1 L2	8.8	8.4	8.9	8.6	9.0	10.0	10.2	10.3
2	FTEs	16.0 L2	35	34	35	34	35	37	37	37

Operating costs are increasing by approximately $0.2 million from fiscal 2019 forecast to fiscal 2020 plan and by approximately $0.1 million from fiscal 2020 plan to fiscal 2021 plan, due to Standard Labour Rate increases. FTEs are planned to remain constant.

5A.6 Stations Asset Planning KBU

5A.6.1 Responsibilities

The primary role of the Stations Asset Planning KBU is the development and management of the maintenance and capital investment plans for the generating station and substation assets. The portfolio of assets managed by Stations Asset Planning consists of:

- 30 hydroelectric generating facilities;
- Two thermal generating facilities;
- One synchronous condenser facility;

- 317 substations; and
- 17 diesel and one hydroelectric generating stations that are not connected to the integrated electric system as well as three standby diesel generating stations.

This KBU was created subsequent to the filing of the Previous Application and consists of a number of departments that were previously part of the former Asset Investment Management KBU, Generation Asset Management KBU and Generation Maintenance KBU.

The Stations Asset Planning KBU consists of the following departments:

- Substations Growth and Sustainment Department;
- Generation Asset Management Department;
- Generating Stations Maintenance Planning Department; and
- Non-Integrated Area Planning Department.

5A.6.1.1. Substations Growth and Sustainment Department

The Substations Growth and Sustainment department is responsible for substation area planning and acts as the asset manager for the electrical, mechanical and civil substation assets. The department develops the capital and maintenance investment plans and facility asset plans for the substation assets and takes on the initiator role for the subsequent capital projects. The various roles on capital projects are discussed further in Chapter 6, section 6.4.7.10.

The department is also responsible for conducting detailed area studies to determine area and substation configurations to serve new and existing loads and to interconnect new generation.

5A.6.1.2. Generation Asset Management Department

The Generation Asset Management department is responsible for developing the long-term investment strategies for the generating station assets, producing and updating the Facility Asset Plans, developing the 10-Year Capital Plan for the generating station assets and assuming the initiator role for the subsequent capital projects.

5A.6.1.3. Generating Stations Maintenance Planning Department

The Generating Stations Maintenance Planning department develops and oversees the $58 million maintenance work plan associated with the generating station assets. This includes developing maintenance programs to preserve equipment functionality, manage asset risk, and comply with regulatory requirements as well as identifying and planning integrated maintenance and short term capital investments for these assets.

5A.6.1.4. Non-Integrated Area Planning Department

The Non-Integrated Area Planning department is responsible for developing and managing the overall maintenance program, the annual maintenance work program and the capital investments for the generating station assets in the 17 Non-Integrated areas.[211]

5A.6.2 Overview of Operating Costs and FTEs

Table 5A-8 Stations Asset Planning KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Stations Asset Maintenance	50.9	0.0	25.9	8.0	0.8	0.0	0.0	**85.7**	-
2	Stations Asset Planning, Director	0.3	0.0	0.0	0.0	0.0	0.0	0.0	**0.3**	1
3	Substations Growth and Sustainment	2.2	0.0	0.2	0.0	0.0	0.0	0.0	**2.4**	20
4	Generation Asset Management	1.5	0.0	0.3	0.0	0.0	0.0	0.0	**1.8**	8
5	Generating Stations Maintenance Planning	1.7	0.0	1.8	0.0	0.0	0.0	0.0	**3.5**	10
6	NIA Planning	0.2	0.0	0.1	0.0	0.0	0.0	0.0	**0.3**	7
7	**Total (Sch 5.1 L3, Sch 16.0 L3)**	**56.9**	**0.0**	**28.3**	**8.0**	**0.8**	**0.0**	**0.0**	**94.0**	**46**

[211] Overall maintenance program refers to the overarching set of activities required to maintain an asset or set of assets over their lifecycle. A maintenance work program refers to the funded set of discrete work items which will be performed on the asset or assets in a defined period of time, usually annually.

In September 2018, 12 FTEs from the Stations Field Operations KBU and one FTE from the Engineering KBU were transferred to the Stations Asset Planning KBU, as part of a re-organization. These FTEs are not reflected in the fiscal 2019 forecast numbers in Table 5A-8 above but are reflected in the fiscal 2020 and fiscal 2021 plan numbers in Table 5A-9.

5A.6.2.1. Stations Asset Maintenance Department

This department holds the budget for the required maintenance work on BC Hydro's generating station and substation assets. Stations Asset Maintenance is discussed further in Chapter 5, section 5.8.

5A.6.2.2. Stations Asset Planning Director Department

This department contains the labour costs for the Director of Stations Asset Planning. In September 2018, one FTE was transferred from the Stations Field Operations KBU to the Stations Asset Planning KBU and one FTE was transferred from the Engineering KBU as part of the re-organization. The labour costs associated with these two transferred positions are reflected in the department's fiscal 2020 budget.

5A.6.2.3. Substations Growth and Sustainment Department

The majority of this department's budget relates to labour costs for 20 FTEs.

There are eight FTEs on the Stations Strategy and Standards team. This team develops the sustaining capital plan and manages the $22 million annual substation maintenance work plan as well as the substation component of the asbestos management and PCB remediation work plans. In addition, this team reviews and accepts 60 to 70 maintenance standards, maintains 17 asset class strategies and produces 10 to 15 asset plans each year.

There are nine FTEs on two regional planning teams. Each year these teams conduct 40 to 60 substation planning studies to address load, sustainment and system needs, three to five annual area planning studies to review substation capability to meet long-term area growth, and 40 system impact studies for customer and generation interconnections.

The remaining three FTEs represent the department manager as well as two FTEs on the analytical studies team who conduct approximately 30 studies each year on the interaction between equipment specifications and system operating performance.

5A.6.2.4. Generation Asset Management Department

The majority of this department's budget relates to labour costs for eight FTEs. Activities conducted by this department include:

- Updating eight to 10 Facility Asset Plans each year;
- Reviewing and accepting 90 to 100 Equipment Health Ratings per year; and
- Developing the portfolio of generating station capital expenditures and initiating approximately 10 to 20 capital projects each year with a total value of approximately $550 million.

5A.6.2.5. Generating Stations Maintenance Planning Department

The Generating Stations Maintenance Planning Department's budget consists of $1.8 million of services costs for external resources and $1.7 million in labour costs for 10 FTEs. In September 2018, an additional 10 FTEs were transferred to this department from the Stations Field Operations KBU. The labour costs associated with these FTEs will be transferred to this department in fiscal 2020.

These FTEs and external resources are organized into the following teams:

- Six FTEs on the Maintenance and Reliability Strategy team. Each year, this team develops approximately 80 equipment level maintenance programs and updates approximately 15 generating station maintenance standards. External resources are used to augment the internal workforce to meet peak workload demands;

- Four FTEs on the Maintenance Planning team who manage six primary asset condition strategies and methodologies, eight asset performance monitoring and equipment programs and compliance with 25 North American Reliability Corporation Mandatory Reliability Standards;
- Seven FTEs on the Investment Planning team who develop and oversee the $58 million annual generating station maintenance work plan, identify regional capital needs and provide field input for capital projects; and
- Three FTEs on the Civil Maintenance team who develop and sustain 15 maintenance standards and identify and deliver 40 civil maintenance projects each year, totalling $4 million.

5A.6.2.6. Non-Integrated Area Planning Department

The majority of this department's budget relates to labour costs for seven FTEs. A significant portion of the costs associated with these positions are charged out to maintenance programs and capital projects.

This department develops and manages the $5 million annual maintenance work program for non-integrated areas and develops, manages and delivers the $14 million capital program for the non-integrated area assets. Further information on maintenance is provided in Chapter 5, section 5.8.

5A.6.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5A-9 Stations Asset Planning KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.1 L3	102.7	102.8	105.4	108.0	106.2	94.0	97.0	98.1
2	FTEs	16.0 L3	51	51	51	49	51	46	59	59

Operating costs are increasing by approximately $3.0 million from the fiscal 2019 forecast to the fiscal 2020 plan due to funding increases to maintenance programs, as described in Chapter 5, section 5.8, transfers related to the September 2018 re-organization described previously, and Standard Labour Rate increases. Operating costs are increasing by approximately $1.1 million from fiscal 2020 plan to fiscal 2021 plan due to Standard Labour Rate increases.

The FTE increase from fiscal 2019 forecast to fiscal 2020 plan reflects the September 2018 re-organization described previously. FTEs are planned to remain constant from fiscal 2020 plan to fiscal 2021 plan.

5A.7 Line Asset Planning KBU

5A.7.1 Responsibilities

The Line Asset Planning KBU is responsible for managing the transmission and distribution system line assets, including meter asset management. To perform these responsibilities, this KBU prepares an integrated asset management plan, which identifies and prioritizes growth and sustainment investment needs across the system. This plan is prepared in collaboration with a number of KBUs across BC Hydro and incorporates asset strategies, system information, planning studies, load forecasts and customer requirements.

The Lines Asset Planning KBU is also responsible for the management of grid telecommunications assets, supporting the telecommunications needs across the Power System.

This KBU was created subsequent to the filing of the Previous Application and consists of a number of departments that were previously part of the former Asset Investment Management KBU.

The Line Asset Planning KBU is organized into the following departments:

- Distribution Planning Department;
- Transmission Planning Department;
- Asset Sustainment Department; and

- Telecommunications, Protection and Control Department.

5A.7.1.1. Distribution Planning Department

The Distribution Planning department is responsible for planning distribution system improvements and growth, advancing the development of smart grid technologies and maintaining compliance requirements. This department also manages the planning, supply, testing, and maintenance of BC Hydro's revenue metering assets in compliance with Measurement Canada requirements.

5A.7.1.2. Transmission Planning Department

The Transmission Planning department is responsible for identifying the short-term and long-term needs and capital expenditures associated with the transmission system. It is also responsible for developing the operational limits and operating instructions for the secure and reliable operation of the Power System. In addition, the department is responsible for the technical planning required to interconnect new industrial loads and generation to the transmission system.

5A.7.1.3. Asset Sustainment Department

The Asset Sustainment department plans and initiates required maintenance work for existing in service lines assets, points of access and vegetation on BC Hydro's system.

This department is responsible for asset sustainment and end of life replacement strategies, asset condition assessment and analysis, asset life-cycle evaluation, end-of-life asset planning, maintenance planning, and maintenance standards review and acceptance.

5A.7.1.4. Telecommunications, Protection and Control Department

The Telecommunications, Protection and Control department is responsible for the development of asset strategies as well as the review and acceptance of standards and investment plans for BC Hydro's telecommunications, protection and control systems. These assets are an integral part of the Power System and provide operators and planners with the ability to monitor, control, and operate the electrical equipment on the system. These assets also provide telecommunications capability across BC Hydro.

This department is also responsible for the sustainment and maintenance of telecommunications, protection and control systems. This includes compliance with all applicable North American Electric Reliability Corporation (**NERC**) and Western Electricity Coordinating Council (**WECC**) standards.

5A.7.2 Overview of Operating Costs and FTEs

Table 5A-10 Line Asset Planning KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Line Asset Maintenance	23.6	0.0	75.5	3.0	6.8	0.0	-8.5	**100.5**	-
2	Distribution Planning	5.6	0.0	1.1	0.0	0.0	0.0	0.0	**6.7**	38
3	Transmission Planning	6.0	0.0	0.2	0.0	0.0	0.0	0.0	**6.3**	42
4	Asset Sustainment	3.0	0.0	2.0	0.0	0.0	0.0	0.0	**5.0**	16
5	Telecom, Protection and Control	2.3	0.0	0.3	0.0	0.0	0.0	0.0	**2.6**	15
6	Line Asset Planning, Director	0.4	0.0	0.1	0.0	0.0	0.0	0.0	**0.4**	2
7	**Total (Sch 5.1 L4, Sch 16.0 L4)**	**40.9**	**0.0**	**79.1**	**3.0**	**6.9**	**0.0**	**-8.5**	**121.4**	**113**

5A.7.2.1. Line Asset Maintenance Department

This department does not contain any FTEs. The budget for this department funds required maintenance work on transmission lines, distribution lines and telecommunications assets. This work is planned by the Lines Asset Planning KBU and delivered by KBUs in the Operations Business Group. A more detailed discussion of the Lines Maintenance programs is provided in Chapter 5, section 5.8.

5A.7.2.2. Distribution Planning Department

This department's budget primarily consists of labour costs for 38 FTEs. Key activities undertaken by these FTEs include:

- Developing and maintaining approximately 20 distribution system strategies, planning criteria, procedures, metering requirements, and guidelines;

- Managing plans for over 1,400 distribution feeders and over 1,500 distribution automation devices on the system;
- Developing approximately 30 feeder evaluations, three integrated planning studies and five distribution area plans annually;
- Evaluating approximately 600 distributed generation customer requests annually;
- Developing annual peak demand forecasts for approximately 220 substations based on load forecast guidelines;
- Planning, engineering, and performing quality assurance of over 2 million smart meters;
- Developing approximately 50 complex meter solutions each year for large industrial customers and IPPs;
- Developing the annual 10-Year Capital Plan to meet the sustainment and growth needs of the BC Hydro distribution system assets, initiating approximately 120 new capital projects each year, including system improvements such as distribution automation; and
- Plans system innovations including electric vehicle charging infrastructure.

The department’s non-labour budget is primarily used to fund distribution system planning studies.

5A.7.2.3. Transmission Planning Department

This department’s budget primarily consists of labour costs for 42 FTEs. Key activities undertaken by these FTEs include:

- Planning significant capital projects to maintain and expand the transmission system;

- Performing an average of 65 transmission customer load connection request studies annually based on external needs;
- Reviewing and updating operating orders as required; and
- Meeting NERC Mandatory Reliability Standards requirements for transmission planning. Each year, the department conducts an average of 14 transmission system planning performance assessments and over 15 operational planning and model verification studies.

The department's non-labour budget is primarily used to fund transmission planning studies.

5A.7.2.4. Asset Sustainment Department

This department's budget primarily consists of labour costs for 16 FTEs. Key activities undertaken by these FTEs include:

- Developing maintenance plans to maintain 900,000 distribution poles, 116,000 transmission poles, 18,000 kilometers of transmission lines and 58,000 kilometers of distribution lines, all within compliance of approximately 100 asset standards;
- Initiating approximately 20 transmission asset failure investigations each year;
- Initiating vegetation management for over 76,000 hectares of transmission right-of-way; and
- Initiating end-of-life or sustaining capital investment.

The department's non-labour budget is primarily used to fund asset failure studies.

5A.7.2.5. Telecommunications, Protection and Control Department

This department's budget primarily consists of labour costs for 15 FTEs. Key activities undertaken by these FTEs include:

- Planning the telecommunications requirements for approximately 150 capital projects and interconnection requests annually;
- Initiating approximately 55 projects and programs annually;
- Managing asset plans for telecommunications, protection and control system failures;
- Managing the annual maintenance programs;
- Producing self-reports and preparing for Western Electricity Coordinating Council onsite audits;
- Meeting telecommunications requirements to connect approximately 8,000 additional meters annually; and
- Managing lifecycle planning for telecommunications assets, including 168 microwave sites supporting the bulk electric system, 194 mobile radio sites supporting field staff, 2000 Cisco grid routers supporting 1.8 million smart meters, and protection and control systems in over 300 substations.

The department's non-labour budget is primarily used to fund planning studies.

5A.7.2.6. Line Asset Planning, Director Department

This department's budget is primarily made up of labour costs for the Director of the Line Asset Planning KBU and an Administrative Assistant.

5A.7.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5A-11 Line Asset Planning KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.1 L4	111.3	107.0	112.0	114.3	111.3	121.4	127.2	128.1
2	FTEs	16.0 L4	109	109	109	112	109	113	116	116

Operating costs are increasing by approximately $5.8 million from fiscal 2019 forecast to fiscal 2020 plan due to funding increases to maintenance programs as described in Chapter 5, section 5.8 as well as Standard Labour Rate increases. Operating costs are increasing by approximately $0.9 million from fiscal 2020 plan to fiscal 2021 plan due to Standard Labour Rate increases.

FTEs are planned to increase by three from fiscal 2019 forecast to fiscal 2020 plan primarily due to conversions of contractors to internal FTEs through the Workforce Optimization Program, which is discussed further in Chapter 5, section 5.6.1. FTEs are planned to remain constant from fiscal 2020 plan to fiscal 2021 plan.

5A.8 Interconnections and Shared Assets

5A.8.1 Responsibilities

The Interconnections and Shared Assets KBU is responsible for:

- Setting interconnections policies and strategies, including managing, revising and enforcing tariff requirements;
- Designing and implementing the process of interconnecting loads and generators, and modifications to BC Hydro's transmission and distribution infrastructure, resulting from third party requests;
- Setting business practices for the quality control, estimating, timelines, reporting and prioritization of interconnection activities;
- Managing the relationship and contract with Telus as Joint Owner of over 80 per cent of the distribution wood poles; and
- Managing third party telecommunication connections to distribution and transmission infrastructure.

The interconnection of residential and small commercial load customers on the distribution system is managed by the Distribution Design and Customer

Connections KBU within the Operations Business Group as discussed in Chapter 5C, section 5C.7.

There have been no material changes to the responsibilities of this KBU since the Previous Application. This KBU consists of the following departments:

- Customer Interconnections and Policy Department;
- Joint Use and Shared Assets Department; and
- Interconnections and Shared Assets Director Department.

5A.8.1.1. Customer Interconnections and Policy Department

The Customer Interconnections and Policy department manages customer requests to interconnect, supply, or receive electrical services from the transmission and distribution system. These requests are from new and existing generators, transmission loads and major distribution loads. In addition, the department manages third-party requests to relocate BC Hydro transmission and distribution infrastructure as well as pipeline proximity and crossing studies.

5A.8.1.2. Joint Use and Shared Assets Department

The Joint Use and Shared Assets department manages the joint ownership and use agreement with Telus (co-owner of approximately 800,000 of our distribution poles) as well as third-party co-location requests which generate additional revenue from our existing transmission and distribution infrastructure. Activities carried out to support these responsibilities include:

- Establishing contractual agreements;
- Managing agreements and billings;
- Co-ordinating the licensee application process;
- Maintaining joint ownership and licensee attachment records;

- Coordinating with other groups within BC Hydro so that the co-location of third-party assets does not compromise the effective operation of the BC Hydro system; and
- Working with other groups within BC Hydro to deliver on contractual obligations and resolve any issues that arise.

5A.8.1.3. Interconnections and Shared Assets Director Department

This department contains the Office of the Interconnections and Shared Assets Director. It is also responsible for managing specialized transmission contracts, technical and commercial agreements with the U.S., Alberta and intra-provincial utilities.

5A.8.2 Overview of Operating Costs and FTEs

Table 5A-12 Interconnections and Shared Assets KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Customer Interconnections and Policy	5.3	0.0	1.4	0.0	0.0	0.0	0.0	**6.8**	29
2	Joint Use and Shared Assets	2.0	0.0	1.6	0.0	0.0	0.0	-2.0	**1.6**	15
3	Interconnections and SA Director	0.5	0.0	0.3	0.0	0.0	0.0	0.0	**0.8**	3
4	**Total (Sch 5.1 L5, Sch 16.0 L5)**	**7.8**	**0.0**	**3.2**	**0.0**	**0.0**	**0.0**	**-2.0**	**9.2**	**47**

5A.8.2.1. Customer Interconnections and Policy Department

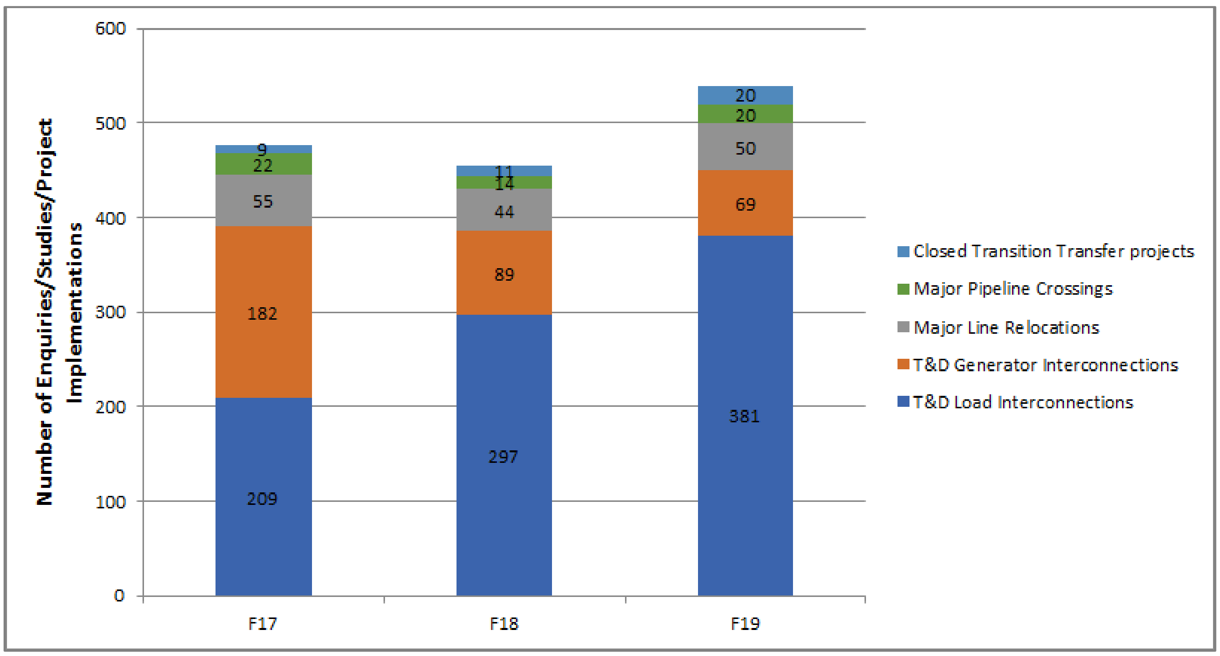
The majority of this department's budget relates to labour costs for 29 FTEs as follows:

- 22 FTEs manage over 500 new customer interconnection enquiries, studies and implementation projects each year; and
- Seven FTEs manage the development and application of distribution tariffs and policies as well as strategic commercial agreements, such as the Ministry of Transportation and Infrastructure protocol agreement.

The department's non-labour budget primarily funds external consultants for interconnection studies.

As shown in Figure 5A-3 below, despite a decrease in work associated with new generator interconnection requests, primarily due to the indefinite suspension of the Standing Offer Program (discussed further in Chapter 4, section 4.3.2), increases in new load interconnection requests and tariff work, such as responding to FERC Order 845[212], have increased the total volume of work managed by this department. The number of FTEs in this department has remained the same.

Figure 5A-3 Interconnections Project Activity



During the test period, BC Hydro expects that generator activities will remain similar to fiscal 2019 levels as existing projects will continue to move through the interconnection process and ongoing work will be required with BC Hydro generators, load displacement projects, and operating generators. BC Hydro also

[212] FERC Order No. 845 is the reform of the OATT Generator Interconnection Procedures and Agreements.

expects that new load interconnection requests and activities will remain consistent or increase during the test period.

5A.8.2.2. Joint Use and Shared Assets Department

The majority of this department's budget relates to labour costs for 15 FTEs as follows:

- Six FTEs on the Joint Use team, five of which are 50 per cent funded by TELUS through the Joint Use Office which administers the joint ownership and use agreement, maintains records, and manages financial recoveries from TELUS. The external recoveries shown in Table 5A-12 primarily relate to the TELUS contributions to joint pole construction and replacement; and
- Nine FTEs on the Shared Assets team. This team manages five different program offerings and processes over 500 applications annually. Eight FTEs on this team are 50 per cent funded through individual application fees related to processing new attachment requests on poles as well as project work to prepare and install licensee equipment on poles. The remaining 50 per cent of the labour costs associated with these FTEs are funded through commercially-agreed annual rental attachment rates. Shared assets annual revenue is included as a part of Miscellaneous Revenue as shown in Appendix A, Schedule 15, line 6 and line 11, and is forecast to be $7.0 million in fiscal 2019.

5A.8.2.3. Interconnections and Shared Assets Director Department

The majority of this department's budget relates to labour costs for three FTEs – the KBU Director, an administrative assistant and a contract specialist.

The department's non-labour budget primarily funds external resources to assist with various commercial negotiations and dispute resolution.

5A.8.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5A-13 Interconnections and Shared Assets KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.1 L5	9.0	10.3	9.1	8.8	9.2	9.2	10.5	10.6
2	FTEs	16.0 L5	40	36	40	43	40	47	47	47

Operating costs are increasing by approximately $1.3 million from fiscal 2019 forecast to fiscal 2020 plan due to Standard Labour Rate increases as well as the transfer of third-party recoveries associated with shared assets from the Interconnections and Shared Assets KBU to the Business Support KBU of the Integrated Planning Business Group. Operating costs are increasing by approximately $0.1 million from fiscal 2019 forecast to fiscal 2020 plan due to Standard Labour Rate increases. FTEs are planned to remain constant.

5A.9 Engineering

5A.9.1 Responsibilities

The Engineering KBU is responsible for providing:

- Engineering, estimating and quality management expertise to support capital projects for power system assets;
- Maintenance engineering and equipment expertise to support the generating stations, transmission substations and the transmission and distribution lines asset; and
- Engineering expertise associated with complex customer interconnection requests, the analysis of critical equipment failures and response to emergency outages involving critical asset and geotechnical failures.

The responsibilities of this KBU have changed since the Previous Application. Engineers responsible for Distribution Engineering and Standards, Generation

Maintenance and Generation Field Maintenance have been transferred into this KBU.

The Engineering KBU consists of the following departments:

- Engineering Department;
- Estimating, Project Engineering and Quality Management Department; and
- Drafting Department.

5A.9.1.1. Engineering Department

BC Hydro's delivery model for the provision of engineering services relies upon a combination of internal staff and external service providers. This model is internally known as the Owner's Engineer Plus model with a portion of the engineering work completed by external service providers and the review and oversight of that work being performed by internal BC Hydro resources (the Owner's Engineer). This department completes approximately 700 Owner's Engineer reviews each year.

As the Owner's Engineer, the Engineering department is accountable for verifying that the overall BC Hydro system is technically capable of safely meeting the operational requirements and demands of its stakeholders, customers, and employees.

This department provides engineering design and oversight to approximately 400 projects each year to ensure the system will meet the requirements of BC Hydro. The level of oversight provided varies depending on the contractual arrangement, type of project, project risk and phase of project implementation. The "Plus" part of the model requires that BC Hydro retains its capability as a knowledgeable owner through employees having the opportunity to build and maintain their skill sets by performing technical design, particularly in areas with high risk and complexity.

The work of the Engineering department is largely governed by engineering standards. It is critical that new standards are generated as needed and that existing standards are refreshed appropriately. Engineering currently has a database of over 4,800 design and maintenance standards. In fiscal 2018, approximately 400 of these standards were updated.

5A.9.1.2. Estimating, Project Engineering and Quality Management Department

This department consists of the Estimating, Project Engineering and Quality Management teams.

The Estimating team produces project cost estimates to support project planning and to aid in the selection of a preferred project alternative and obtain funding approval. This team also provides expertise to assist with project and construction planning, construction methodology, and sequencing. On average, the estimating team prepares over 150 estimates per year. The effort to prepare an estimate typically ranges from 100 to 1,000 hours depending on the level of complexity of the project. They review estimates prepared by external service providers, and provide support to proposal/bid evaluation, change orders and contract claims.

The Project Engineering team coordinates the engineering on the more complex, multi-disciplinary generating stations, transmission substations, and some transmission lines and distribution lines projects. This team has the overall responsibility for the engineering scope, schedule, and cost of a project through to completion, and is responsible for assessing whether end products are fit for purpose and meet the needs of BC Hydro.

The Quality Management team's primary responsibility is to assess whether the quality of equipment supplied from the marketplace meets BC Hydro's standards and requirements. Quality Management engineers and Quality Assurance representatives work directly with equipment manufacturers, engineering service providers, and contractors to perform these assessments.

Through audits, inspections, and tests, Quality Management and Engineering Departments engage with suppliers of equipment for approximately 400 projects each year. In addition, Quality Management and the Engineering Departments contribute to the Supply Chain KBU's Category Management procurement initiatives to support successful receipt of engineered equipment such as power transformers, switchgear and electrical components. On an annual basis, the Quality Management and engineering Departments team perform more than 6,000 inspections.

5A.9.1.3. Drafting Department

The Drafting department supports engineering and capital projects with the production of new drawings and the revision of existing drawings. Drafting also supports the development and application of drawing and drafting standards and processes. BC Hydro receives a large volume of drawings produced by external consultants and equipment suppliers and must assess the quality and compliance of these drawings to BC Hydro's drafting standard. This department also creates, maintains and updates drawings for the operation of BC Hydro's system, including the Geographic Information System. The Drafting department produces approximately 50,600 Computer-Aided Design and Drafting (**CADD**) drawings each year.

5A.9.2 Overview of Operating Costs and FTEs

Table 5A-14 Engineering KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	General Manager, Engineering	0.4	0.0	0.2	0.1	0.0	0.0	0.0	**0.7**	(20)
2	Engineering	14.1	0.0	2.1	0.2	0.6	0.0	0.0	**17.0**	436
3	Estimating, Prj Engineering and Qual Mgmt	2.1	0.0	0.1	0.0	0.0	0.0	0.0	**2.3**	73
4	Drafting	1.3	0.0	0.1	0.1	0.3	0.0	0.0	**1.8**	96
4	**Total (Sch 5.1 L6, Sch 16.0 L6)**	**17.9**	**0.0**	**2.6**	**0.4**	**0.9**	**0.0**	**0.0**	**21.8**	**586**

In September 2018, FTEs were transferred from the Stations Field Operations KBU to the Engineering KBU as part of a re-organization. These FTEs are not reflected in the fiscal 2019 forecast numbers in Table 5A-14 above but are reflected in the fiscal 2020 plan numbers in Table 5A-15.

5A.9.2.1. General Manager, Engineering Department

This department primarily consists of labour costs for two FTEs – The General Manager of Engineering and an Administrative Assistant. The FTE count for this department is negative because it reflects vacancy factor savings of 3.6 per cent (22 FTEs). For more information on vacancy factor savings, please see Chapter 5, section 5.5.2.3.

This department's non-labour budget of $0.2 million is primarily for generating stations, transmission lines and distribution lines standards development performed by contractors.

5A.9.2.2. Engineering Department

This department has 436 FTEs. Approximately 76 per cent of the labour costs for these FTEs are not included in this department's budget as these costs are charged primarily to capital projects. Non-chargeable time is spent on activities that cannot be capitalized (e.g., standards development, engineering studies, and the implementation of category management strategies to procure external resources and electrical and mechanical equipment) as well as other activities such as managing staff, team meetings, professional training and safety training.

The department's non-labour budget includes $0.9 million for Innovation and Technical memberships, $0.6 million in travel and training expenses, $0.3 million for engineering contractor time that cannot be capitalized and $0.2 million for professional dues and fees. The department's Building and Equipment budget primarily consists of software licensing and maintenance costs.

5A.9.2.3. Estimating, Project Engineering and Quality Management Department

This department consists of 73 FTEs, which reflects the level of resources required to deliver BC Hydro's capital plan and operational requirements. Approximately 80 per cent of the labour costs for these FTEs are not included in the operating costs budget as these costs are charged primarily to capital projects. Non-chargeable time is spent on activities that cannot be capitalized (e.g., quality manual development, engineering studies, and the implementation of category management strategies to procure external resources and electrical and mechanical equipment) as well as other activities such as managing staff, team meetings, professional training and safety training.

5A.9.2.4. Drafting Department

This department consists of 96 FTEs, which reflects the level of resources required to deliver BC Hydro's capital plan and operational requirements. Approximately 83 per cent of the labour costs for these FTEs are not included in the operating costs budget as these costs are charged primarily to capital projects. Non-chargeable time is spent on activities that cannot be capitalized (e.g., standards development and Geographic Information System improvements) as well as other activities such as managing staff, team meetings, professional training and safety training.

The Buildings and Equipment budget for this department is primarily for software licensing maintenance.

5A.9.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5A-15 Engineering KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.1 L6	19.9	19.2	20.2	20.5	20.5	21.8	24.7	25.1
2	FTEs	16.0 L6	536	540	536	558	536	586	646	646

Operating costs are increasing by approximately $2.9 million from fiscal 2019 forecast to fiscal 2020 plan due to the net impact of transfers related to the September 2018 re-organization of $2.1 million and due to Standard Labour Rate increases of $0.8 million. Operating costs are increasing by approximately $0.4 million from fiscal 2020 plan to fiscal 2021 plan due to Standard Labour Rate increases.

FTEs are increasing by 60 from fiscal 2019 forecast to fiscal 2020 plan due to the September 2018 re-organization and the addition of four positions to support NERC cyber security requirements for BC Hydro's protection and control equipment, as discussed further in Chapter 5C, section 5C.10.3. FTEs are expected to remain constant from fiscal 2020 plan to fiscal 2021 plan.

The increase in FTEs from fiscal 2019 RRA to fiscal 2019 forecast was primarily driven by the Workforce Optimization program, described in Chapter 5, section 5.6.1.

5A.10 Business Unit Support

5A.10.1 Responsibilities

The Business Unit Support KBU holds the budget for the Office of the Senior Vice President, Integrated Planning, for business group costs that are not specifically related to any single KBU, and for project pre-capitalization expenditures.

5A.10.2 Overview of Operating Costs and FTEs

Table 5A-16 Business Unit Support KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	SVP, Integrated Planning	0.7	0.0	0.2	0.0	0.0	0.0	0.0	**0.9**	3
2	Common Costs	0.0	0.0	2.3	0.7	0.0	0.0	0.0	**3.1**	-
3	Project O&M	6.3	0.0	5.7	0.0	0.0	0.0	0.0	**12.0**	-
4	**Total (Sch 5.1 L7, Sch 16.0 L7)**	**7.0**	**0.0**	**8.3**	**0.7**	**0.0**	**0.0**	**0.0**	**16.0**	**3**

5A.10.2.1. SVP, Integrated Planning Department

The majority of this department's budget relates to labour costs for three FTEs – the Senior Vice President of Integrated Planning, a strategic business advisor and an Administrative Assistant. The department's non-labour budget provides funding for contract services, employee travel and training.

5A.10.2.2. Common Costs Department

This department does not have any FTEs. Approximately $1.6 million of this department's budget is for First Nations Community Fund payments in lieu of taxation, approximately $0.6 million is a maintenance reserve to fund emerging and unplanned maintenance items, and approximately $0.7 million is for minor materials, such as nuts and bolts, used in maintenance programs.

5A.10.2.3. Project Operations and Maintenance Department

This department's budget includes expenses incurred to determine or confirm a need or opportunity for a capital project, and to develop, review and recommend conceptual alternatives for the potential project.

These costs are incurred by a project after its release but prior to the identification of a leading alternative solution and are referred to as Capital Project Investigation expenditures.

This department's budget may also fund chartered planning study costs for discrete study work to be completed prior to the release of a project. These chartered studies supplement and support the base study work done in the Integrated Planning KBUs.

Capital Project Investigation expenditures vary year-to-year depending on the size, complexity and volume of projects. Please refer to Chapter 6, section 6.4.7.5 for a further discussion of BC Hydro's capital project lifecycles.

5A.10.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5A-17 Business Unit Support KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.1 L7	13.1	31.3	7.6	17.6	7.6	16.0	13.2	12.5
2	FTEs	16.0 L7	4	4	4	3	4	3	3	3

Operating costs are decreasing by approximately $2.8 million from fiscal 2019 forecast to fiscal 2020 plan due to the transfer of third-party recoveries from shared assets from the Interconnections and Shared Assets KBU and due to a reduction of Capital Project Investigation expenditures.

Operating costs are decreasing by $0.7 million from fiscal 2020 plan to fiscal 2021 plan, primarily due to a transfer to the Energy Planning and Analytics KBU to provide additional funding for the development of the 2021 IRP.

FTEs for Integrated Planning Business Unit Support are planned to remain constant from fiscal 2019 forecast to fiscal 2020 and fiscal 2021 plan.

Fiscal 2020 to Fiscal 2021

Revenue Requirements Application

Chapter 5B

Operating Costs

Capital Infrastructure Project Delivery

Business Group

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5B.1 Introduction – Capital Infrastructure Project Delivery Business Group

Chapter 5B provides and explains in detail the composition of, and rationale for, the operating costs of the Capital Infrastructure Project Delivery Business Group. The Capital Infrastructure Project Delivery Business Group is one of six Business Groups in the organization and is responsible for building BC Hydro's assets. It serves as the Build function of the Plan-Build-Operate-Support model.

The Capital Infrastructure Project Delivery Business Group budget was developed as part of the budgeting process outlined in Chapter 5, section 5.4. The information provided in this Chapter 5B demonstrates the basis for the entirety of the Business Group and KBU budgets, rather than focussing only on incremental cost requirements.

Chapter 5B is organized as follows:

- Section 5B.2 provides an overview of the organization and responsibilities of the Capital Infrastructure Project Delivery Business Group;
- Section 5B.3 provides the operating costs and FTE information for the Capital Infrastructure Project Delivery Business Group as a whole;[213]
- Sections 5B.4 to 5B.8 provide more detailed information on the responsibilities, cost and FTEs for each KBU within the Capital Infrastructure Project Delivery Business Group. The operating costs and FTE information for each KBU is broken out into two sections.[213]
  - Overview of Operating Costs and FTEs – This section explains the starting operating costs and FTEs based on the fiscal 2019 forecast; and

[213] Please note the amounts presented in the tables in these sections may not add due to rounding.

- Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs – This section explains any incremental changes between fiscal 2019 forecast and fiscal 2020 and fiscal 2021 plan.

5B.2 Overview of Capital Infrastructure Project Delivery Business Group Organization and Responsibilities

The Capital Infrastructure Project Delivery Business Group is responsible for delivering BC Hydro's larger and more complex capital projects while also providing cross-company services relating to the management and support of Indigenous relations, environment, and properties. Given the intersection between lands, First Nations matters, environment, and capital projects, it makes sense to have the KBUs with responsibility for these key areas within the same Business Group. These KBUs work together to secure the necessary permitting and approvals, support, and land rights to successfully deliver BC Hydro's capital projects in an increasingly complex environment.

During the test period, the Capital Infrastructure Project Delivery Business Group plans to deliver approximately 50 per cent of BC Hydro's overall Capital Plan (excluding the Site C Project). This includes the majority of the generation, stations, dam safety, and transmission projects as well as some larger distribution and properties projects. These projects can be expected to give rise to the environmental, land, and First Nations considerations that are the responsibility of the KBUs in this Business Group.

The Capital Infrastructure Project Delivery Business Group consists of the following KBUs:

Business Group	Key Business Unit
Capital Infrastructure Project Delivery	Project Delivery Indigenous Relations Environment Properties Business Unit Support

Since the Previous Application, the Dam Safety and Engineering (formerly Generation and Transmission Engineering) KBUs have been transferred to the Integrated Planning Business Group.

5B.3 Fiscal 2020 and Fiscal 2021 Plan Operating Cost and FTE Summaries

This section addresses planned operating costs and FTEs for the Capital Infrastructure Project Business Group. The following are some key points of note with respect to the information provided in Figure 5B-1, Table 5B-1 and Figure 5B-2, Table 5B-1 and Table 5B-3:

- The majority of the FTEs in this Business Group charge a portion of their labour to capital projects. For example, the Project Delivery KBU charges out approximately 83 per cent of its labour costs to capital projects; and
- Approximately $37 million (47 per cent) of the total operating expenditures of this Business Group are non-labour expenditures, directly attributable to BC Hydro building maintenance and environmental programs such as the Fish & Wildlife Compensation Program, non-remissible Water Rights projects, and the Williston Dust Management Program.

Planned operating costs for the Capital Infrastructure Project Delivery Business Group are approximately $80.1 million in fiscal 2020 and approximately $81.1 million in fiscal 2021. The operating costs for the Capital Infrastructure Project Delivery Business Group are summarized by KBU in Figure 5B-1. Additional cost detail is provided in Table 5B-1 below.[214]

[214] Please note that a significant portion of costs in the Project Delivery KBU are charged out to capital projects and not included in the KBU's operating cost budget.

Figure 5B-1 Capital Infrastructure Project Delivery Net Operating Costs by KBU (Fiscal 2020 Plan) ($ million)

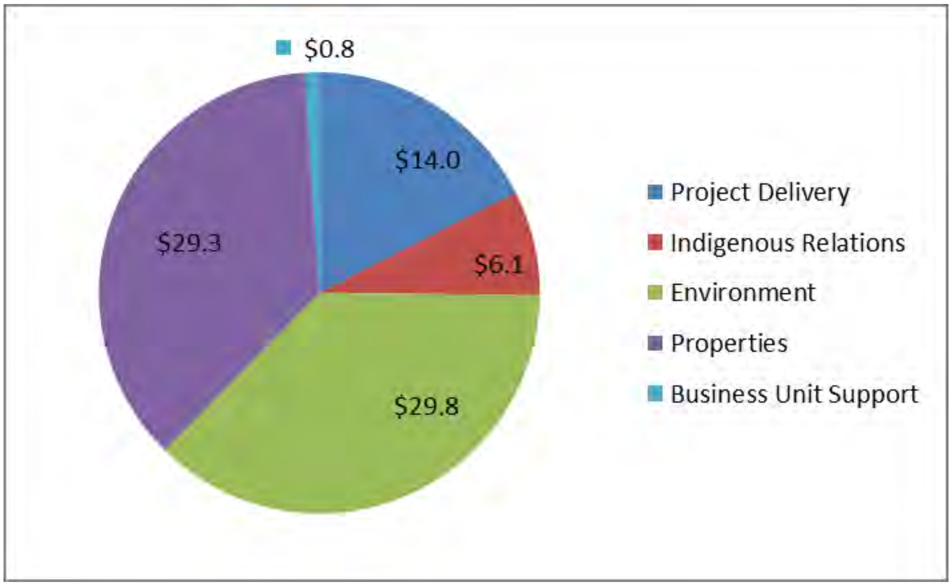

Table 5B-1 Capital Infrastructure Project Delivery Net Operating Costs by KBU

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Project Delivery	5.2 L1	13.4	12.7	14.2	13.5	14.3	13.9	14.0	14.5
2	Indigenous Relations	5.2 L2	6.1	7.3	6.1	6.1	6.1	6.3	6.1	6.3
3	Environment	5.2 L3	27.2	26.2	27.5	27.0	27.8	29.2	29.8	30.0
4	Properties	5.2 L4	32.2	32.2	32.5	32.7	32.8	32.7	29.3	29.5
5	Business Unit Support	5.2 L5	0.8	0.7	0.8	0.7	0.8	0.8	0.8	0.9
6	Total	5.2 L12	79.7	79.2	81.1	79.9	81.9	82.9	80.1	81.1

The FTEs for the Capital Infrastructure Project Delivery Business Group are summarized by KBU in Figure 5B-2. Additional detail is provided in Table 5B-2 below.

Figure 5B-2 Capital Infrastructure Project Delivery FTEs by KBU (Fiscal 2020 Plan)

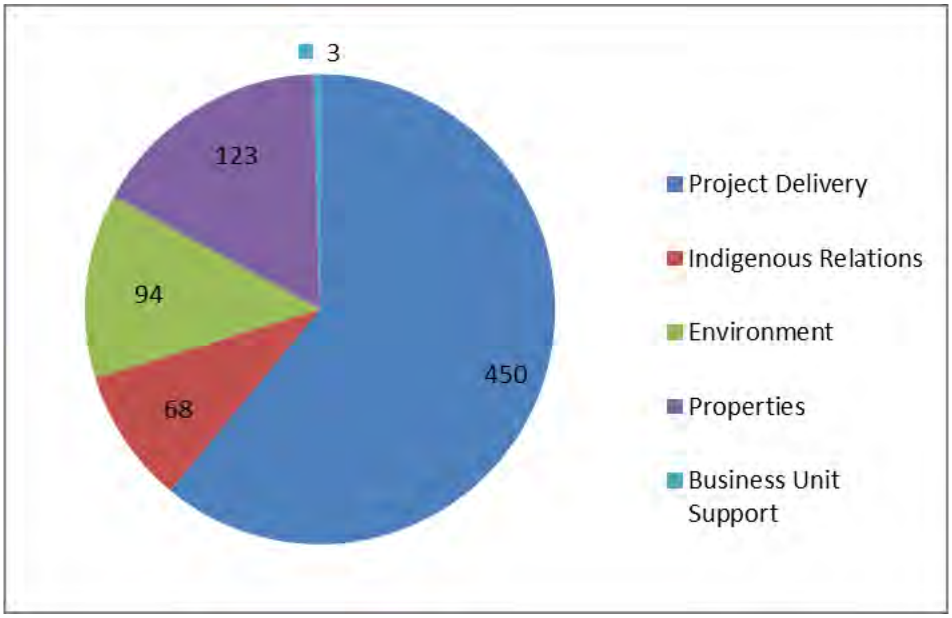

Table 5B-2 Capital Infrastructure Project Delivery FTEs by KBU

	(FTEs)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Project Delivery	16.0 L9	340	324	368	387	368	453	450	450
2	Indigenous Relations	16.0 L10	47	57	47	59	47	68	68	68
3	Environment	16.0 L11	83	86	83	90	83	89	94	94
4	Properties	16.0 L12	106	110	106	114	106	124	123	123
5	Business Unit Support	16.0 L13	3	3	3	3	3	3	3	3
6	Total	16.0 L14	579	581	607	652	607	737	739	739

Table 5B-3 below provides a continuity table which highlights changes to the Capital Infrastructure Project Delivery Business Group from the Previous Application. An overall discussion of these changes, at a company-wide level, is provided in Chapter 5, section 5.5.2. Further details, by KBU, are provided in the sections below.

Table 5B-3 Capital Infrastructure Project Delivery Operating Costs Continuity Schedule

	($ million)		F2020 Plan	F2021 Plan
1	F2019 Revenue Requirement Application Plan (Capital Infrastructure Project Delivery)		52.1	
2	Reorganization Impacts		29.8	
3	F2019 Revenue Requirement Application Plan (Capital Infrastructure Project Delivery Integrated)		81.9	
4	Budget Transfers Between Business Groups		1.0	
5	Adjusted F2019 Revenue Requirement Application Forecast (Capital Infrastructure Project Delivery Integrated) / carry forward plan (Schedule 5.2, line 12)	A	82.9	80.1
6	Current Year Budget Transfers Between Business Groups	B	(0.2)	
7	Test Period Savings			
8	Lease accounting standard		(2.0)	
9	Lease termination savings		(1.2)	
10	Vacancy factor savings		(1.6)	
11		C	(4.9)	-
12	Test Period Cost Increases			
13	Labour		2.2	1.0
14		D	2.2	1.0
15	Test Period Net Increase/(Decrease)	E=C+D	(2.7)	1.0
16	Net Operating Costs (Schedule 5.2, line 12)	A+B+E	80.1	81.1

5B.4 Project Delivery

5B.4.1 Responsibilities

The Project Delivery KBU is responsible for safely delivering a multi-billion dollar portfolio of Power System capital projects on time and on budget. During fiscal 2020 and fiscal 2021, this KBU will be managing approximately 400 dam safety, stations, lines and interconnection projects, which represent 54 per cent or $1.4 billion of BC Hydro’s Power System Capital Plan during the test period. Further information on this plan is provided in Chapter 6, section 6.4. Projects managed by this KBU typically range in cost from $1 million to $1 billion, with durations of one year to more than 10 years.

The Project Delivery KBU provides the following functions:

- Overall project and portfolio management;
- Project Services including project standards and controls, document management, cost and schedule management, and risk management; and
- Project construction and contract management.

Projects managed by the Project Delivery KBU require analysis of project alternatives, risks and methods of execution. For consistent management of project risk, scope, schedule and cost, this KBU uses the Project and Portfolio Management (**PPM**) System, which is discussed further in Chapter 6, section 6.4.7. This system aligns and integrates with work from other KBUs to deliver projects on time and on budget while also meeting our commitments from an environmental, Indigenous relations and stakeholder perspective.

Project Delivery's PPM System has been established following best practices from the Project Management Institute. In 2016, BC Hydro's practices were assessed against the Project Management Institute's Organizational Project Management Maturity Model, the globally-recognized, industry-practice standard for assessing and developing capabilities in portfolio, program and project management. BC Hydro received a maturity rating of 91 per cent out of a possible 100 per cent for Best Practices that were marked as applicable to project delivery. This positioned BC Hydro in the top-tier of organizations globally. Also in 2016, BC Hydro received the Project Management Office of the Year Award from the Project Management Institute.

A measure of BC Hydro's ability to deliver capital projects on budget is included in BC Hydro's Service Plan, with a target of actual costs falling within +5 per cent to -5 per cent of the original approved expected cost in aggregate, excluding project reserve amounts. For the five-year period of fiscal 2014 to fiscal 2018, the projects included in this metric had an aggregate original approved expected cost of $6.9 billion[215]. The actual aggregate costs for these projects were $27.9 million (or 0.40 per cent) over the original approved expected cost. Since fiscal 2014 when BC Hydro began measuring its capital delivery performance with a five-year aggregate, it has been within the target range. Chapter 6, section 6.2.1.2 provides further information on BC Hydro's performance in the delivery of capital projects.

[215] The majority of these projects were delivered by the Project Delivery KBU.

In 2018, the Project Delivery KBU consolidated its management team, resulting in a reduction of departments from nine to six. The purpose of this consolidation was to better align with how the Integrated Planning and Operations Business Groups are organized (i.e., by asset type) and to strengthen collaboration. Consolidating the Project Delivery Portfolio departments has reduced the number of direct reports to the Vice President of Project Delivery, by three.

There have been no material changes to the responsibilities of this KBU since the Previous Application.

The Project Delivery KBU consists of the following departments:

- Three Project Delivery Portfolio Departments (Dam Safety Projects and Programs, Stations Projects and Lines and Interconnection Projects);
- Capital Construction Department; and
- Project Services Department.

5B.4.1.1. Project Delivery Portfolio Departments

Each of the three Project Delivery Portfolio departments manage different types of projects. They all follow the PPM System to deliver capital projects safely, on time, on budget and to the project requirements. The Project Delivery portfolio departments’ responsibilities include the following key activities:

- Ensuring project alternatives are evaluated to best address the needs and objectives of the project and BC Hydro;
- Managing the scope, risk, schedule and cost of the project; and
- Delivering projects in accordance with approved policies and practices.

5B.4.1.2. Capital Construction Department

As projects move into the Implementation Phase, the Capital Construction department works with project managers and on-site contractors to deliver projects safely, on time, on budget and to project requirements. Capital Construction's responsibilities include the following:

- Mitigating project cost and schedule risk by delivering constructability reviews during the project lifecycle;
- Providing rigorous contract management during pre-award and post-award phases to ensure all contractual requirements are met by BC Hydro contractors;
- Planning and managing on-site project construction and commissioning activities;
- Overseeing the on-site safety of BC Hydro employees and contractors in accordance to applicable safety and technical standards; and
- Performing quality assurance, testing and acceptance to verify new equipment will perform as expected over the life of the asset.

This department primarily supports the Project Delivery KBU but also manages contracts for other KBUs involved in delivering the Power System Capital Plan.

5B.4.1.3. Project Services Department

The Project Services department is responsible for the PPM System that ensures practices and tools are used to consistently deliver capital projects. The department also provides centralized project support services for the planning, management and reporting of projects and portfolios following project management industry-standards. Project Services responsibilities include the following:

- Preparing financial, risk and resource management plans, as well as management and executive reports for the Project Delivery portfolio;
- Developing reliable project schedules, cost forecasts and analysis using industry-standard practices;

- Supporting project managers by preparing business cases, alternative analysis, and regulatory applications, and facilitating structured decision making;
- Managing documents and records for projects and contracts throughout the project lifecycle including project closure and evaluation reporting and archiving; and
- Developing and continuously improving the PPM System as well as providing training, and conducting conformance reviews.

5B.4.2 Overview of Operating Costs and FTEs

Table 5B-4 Project Delivery KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	VP, Project Delivery	0.2	0.0	0.1	0.0	0.0	0.0	0.0	**0.3**	(16)
2	Dam Safety Projects and Programs	0.8	0.0	0.1	0.0	0.0	0.0	0.0	**0.9**	32
3	Stations Projects	0.5	0.0	0.0	0.0	0.0	0.0	0.0	**0.6**	24
4	Lines and Interconnections Projects	0.8	0.0	0.1	0.0	0.0	0.0	0.0	**0.9**	34
5	Capital Construction	4.2	0.0	0.9	0.1	0.2	0.0	0.0	**5.4**	234
6	Project Services	5.1	0.0	0.6	0.1	0.0	0.0	0.0	**5.8**	144
7	**Total (Sch 5.2 L1, Sch 16.0 L9)**	**11.8**	**0.0**	**1.8**	**0.2**	**0.2**	**0.0**	**0.0**	**13.9**	**452**

Overall FTEs in the Project Delivery KBU are primarily driven by the size of the Power System Capital Plan. This KBU forecasts its human resource requirements using the Project Delivery Resource Management approach which involves:

- Determining labour demand for active projects based on resource-loaded schedules;
- Modelling and determining labour demand for planned projects using historic inputs from previous projects;
- Comparing labour demand, per discipline, with internal resource capacity;
- Determining the appropriate resource allocation strategy. To meet demand, projects are resourced by BC Hydro employees and are augmented by external

services providers. This provides flexibility to respond to changes in the size or complexity of the capital plan; and

- Monitoring resource needs and overtime to adjust resourcing as required.

Within the Project Delivery KBU, this approach is used to forecast demand for project managers, construction managers, contract managers, construction officers, schedulers, cost analysts and commercial managers. This approach covers approximately 70 per cent of the project resource demand from the Project Delivery KBU, and is continuing to be developed to cover additional disciplines.

Where this approach is not used (e.g., project standards and controls, document management, portfolio management, and administration), resource demand forecast based on expected workload, compared with available capacity and resource strategies are developed accordingly.

Approximately 83 per cent of total Project Delivery KBU labour costs are capitalized to capital projects and not included in the KBU’s operating costs. The remaining 17 per cent of labour costs make up approximately 84 per cent of the KBU’s overall operating costs. The remaining 16 per cent of the KBU’s operating costs are related to services, equipment and materials.

Under BC Hydro’s accounting guidelines, several activities required to deliver the BC Hydro’s Power System Capital Plan cannot be capitalized. Examples of non-capitalized project management related labour includes management and reporting, PPM System enhancement and sustainment, safety training, professional development and administrative support.

5B.4.2.1. Office of Vice President Project Delivery Department

This department contains the labour costs for the Vice President of Project Delivery and an administrative assistant. The FTE count for this department is negative because it reflects vacancy factor savings of 18 FTEs, which is discussed further in Chapter 5, section 5.5.2.3.

5B.4.2.2. Project Delivery Portfolio Departments

Project managers report to either a team lead or the Project Delivery Director for the delivery of the project against approved scope and objectives in accordance with approved policies and practices. More information is provided in Chapter 6, section 6.4.7.10.

Project managers are expected to manage one to eight projects at any one time (average is five projects per project manager). The number of projects varies based on project complexity, project size, project timing and experience of the project manager. The labour capitalization rate for project managers is 93 per cent. The capitalization rate for all positions across all three portfolios (Dam Safety Projects and Programs, Stations Projects and Lines and Interconnection Projects) is 81 per cent.

There are a total of 90 FTEs across the three Project Delivery portfolio departments. The current labour mix is approximately 85 per cent internal resources and 15 per cent external service providers and contractors (based on project count). This provides sufficient flexibility for BC Hydro to respond to changes to the capital plan.

5B.4.2.3. Capital Construction Department

The Capital Construction department workload is primarily driven by Power System capital projects in the Implementation Phase. At any one time, the department is supporting over 375 projects (including other KBUs involved in delivering the Power System Capital Plan), and is managing over 1,600 contracts with a total value of over $3.9 billion. These contracts cover over 500 vendors.

Construction managers and construction officers have a labour capitalization rate of 93 per cent. The blended labour capitalization rate for the department is 84 per cent.

There are 234 FTEs across the Capital Construction department, organized into the following teams:

- Office of the Director of Capital Construction –Two FTEs;
- Capital Construction Services – 40 FTEs provide contract administration services of over 1600 contracts;
- Specialist Services – 52 FTEs provide construction planning, constructability review, testing and commissioning, supply contract management, claims management, and construction practice management; and
- Construction and Contract Management – 140 FTEs provide on-site project construction and contract management.

Management targets a resource mix of 70 per cent internal and 30 per cent external resources. This provides sufficient flexibility to adjust for changes in the capital plan, as well as location and seasonality of work.

5B.4.2.4. Project Services Department

The Project Services department supports Power System capital projects throughout the project lifecycle. At any one time, the department is supporting approximately 400 projects. The labour capitalization rate for the overall Project Services department is 69 per cent. Resources, such as schedulers, commercial managers and cost analysts, have a higher capitalization rate of 85 per cent to 90 per cent.

This department consists of 144 FTEs organized into the following teams:

- Office of the Director of Project Services – Two FTEs;
- Portfolio Management – Eight FTEs provide monthly project and portfolio reporting for approximately 400 projects, coordinate the release of 40 projects from the Integrated Planning Business Group annually, model resource demand for 60 disciplines, and coordinate portfolio and business planning;
- Project Scheduling and Costing – 58 FTEs provide scheduling and cost planning, analysis and reporting for approximately 400 projects. Annually this

team leads over 4,200 project schedule and cost forecast updates annually for 7,500 work packages;

- Commercial Management – 14 FTEs provide support to approximately 150 more complex Project Delivery projects (typically over $10 million) by preparing business cases, conducting structured decision making and risk workshops and preparing financial analysis of project alternatives. This team also prepares approximately 10 regulatory applications and compliance filings annually;
- Document Management – 51 FTEs provide document control and archiving. Each year, these FTEs manage 900,000 project documents within the PPM document system, process 30,000 contract transmittals and submittals, and archive over 90,000 project documents; and
- Standards, Controls and Tools - 11 FTEs provide practices, tools and learning for the PPM System as well as prepare over 150 compliance, quality and project closure reports and conduct 48 conformance audits annually to ensure that the practices and process of the PPM System are be consistently applied.

5B.4.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5B-5 Project Delivery KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.2 L1	13.4	12.7	14.2	13.5	14.3	13.9	14.0	14.5
2	FTEs	16.0 L9	340	324	368	387	368	453	450	450

Operating costs are increasing by approximately $0.1 million from the fiscal 2019 forecast to fiscal 2020 plan and by approximately $0.5 million from the fiscal 2020 plan to fiscal 2021 plan, due to Standard Labour Rate increases.

FTEs are planned to decrease by two from the fiscal 2019 forecast to the fiscal 2020 plan. This reflects the consolidation of the Project Delivery management team, discussed above.

The increase in FTEs from the fiscal 2019 RRA to the fiscal 2019 forecast was primarily driven by the Workforce Optimization Program, described in Chapter 5, section 5.6.1.

5B.5 Indigenous Relations

5B.5.1 Responsibilities

The Indigenous Relations KBU is responsible for establishing and implementing a company-wide approach to develop and sustain positive long-term relationships with First Nations. This approach supports a company-wide understanding of First Nations interests so that they can be incorporated, where possible and appropriate, into BC Hydro's capital projects, programs and operations activities. This approach aligns with:

- BC Hydro's Statement of Indigenous Principles which guides how we engage with First Nations;
- our legal obligation to consult with First Nations; and
- First Nations' expectations on how we address their interests and perspectives.

Indigenous Relations' responsibilities with First Nations include:

- Developing and sustaining positive long-term relationships;
- Engaging and consulting on BC Hydro's projects, programs and operations;
- Developing and implementing agreements; and
- Pursuing opportunities for training and employment.

Through engagement and consultation with First Nations and the implementation of commitments to First Nations in agreements, the Indigenous Relations KBU works with subject matter experts across the company, such as the Environment and Human Resources KBUs.

While the general responsibilities of this KBU are unchanged since the Previous Application, a key area requiring increased focus is incorporating the United Nations Declaration on the Rights of Indigenous Peoples (**UNDRIP**) and Calls to Action of the Truth and Reconciliation Commission (**TRC**) into our business activities. BC Hydro is supporting the Government of B.C.'s commitment to reconciliation with First Nations, as directed by the Government of B.C. in its Mandate Letter to BC Hydro in fiscal 2018.[216]

A key performance indicator of BC Hydro's effectiveness in Indigenous relations is our attainment of a third consecutive gold-level certification for Progressive Aboriginal Relations (**PAR**), from the Canadian Council for Aboriginal Business[217]. PAR is a certification program that confirms corporate performance in Aboriginal relations at the Bronze, Silver or Gold level. It evaluates four areas of performance including: leadership actions, employment, business development and community relations. PAR certification provides a high degree of assurance to First Nations communities, as the designation is supported by an independent, third party verification and is determined by a jury comprised of Aboriginal business people. BC Hydro has attained gold level certification since 2012 and was recently awarded another gold level certification for a three year period to 2021.

The Indigenous Relations KBU consists of the following departments:

- Regional Relationship and Consultation Departments (Southwest, Southeast, and North);

[216] Appendix E provides BC Hydro's mandate letter from the Government of B.C.

[217] The Canadian Council for Aboriginal Business is a non-partisan / non-profit organization founded in 1984, to support the participation of Aboriginal Peoples in Canada's economy. There are approximately 36 Canadian organizations participating in the PAR program, at various levels of certification.

- Indigenous Employment, Training and Communications Department; and
- Business Operations and Negotiations Department.

5B.5.1.1. Regional Relationship and Consultation Departments

The three regional departments are responsible for managing BC Hydro's overall relationships and consultation with First Nation communities across the province. This ensures that BC Hydro meets its legal obligation to consult with First Nations, and that capital projects, programs and operating activities are effectively delivered.

The regional departments develop and implement agreements with First Nation communities who may be impacted by the operation of BC Hydro's Power System and upcoming capital projects.

5B.5.1.2. Indigenous Employment, Training and Communications Department

The Indigenous Employment, Training and Communications department enables BC Hydro to attract and retain Indigenous employees in its workforce, and to meet its commitments in agreements with First Nations. The department provides direct support to First Nations and Indigenous people at a community level. This support includes community engagement and awareness, training, work experience as well as scholarships/ bursary programs, and apprenticeships.

5B.5.1.3. Business Operations and Negotiations Department

The Business Operations and Negotiations department is responsible for developing and administering Indigenous Relations' engagement and consultation practices that support delivery of capital projects, programs and operations activities, so that these activities meet our legal obligation to consult with First Nations. This department is responsible for following emerging policy (e.g., UNDRIP and TRC) and case law and seeking legal counsel and perspectives to ensure that our engagement and consultation practices evolve.

The department is also responsible for leading agreement negotiations, managing the consultation and commitment tracking information system, and performance reporting.

5B.5.2 Overview of Operating Costs and FTEs

Table 5B-6 Indigenous Relations KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Indigenous Relations Director	0.4	0.0	0.2	0.0	0.0	0.0	0.0	**0.6**	2
2	Regions	2.3	0.0	0.9	0.0	0.0	0.0	0.0	**3.3**	42
3	Indigenous Employmt Training and Comm	1.0	0.0	0.3	0.0	0.0	0.0	0.0	**1.3**	13
4	Business Ops and Negotiations (BON)	1.1	0.0	0.0	0.0	0.0	0.0	0.0	**1.2**	12
5	**Total (Sch 5.2 L2, Sch 16.0 L10)**	**4.7**	**0.0**	**1.5**	**0.1**	**0.0**	**0.0**	**0.0**	**6.3**	**69**

This KBU consists of 69 FTEs. Approximately 47 per cent of the KBU's total labour costs are not shown in the operating cost budget as these costs are charged to capital projects.

Overall, operating labour costs make up 75 per cent of the Indigenous Relations KBU operating costs. The majority of the remaining non-labour portion is required to develop and implement agreements with First Nations and to attract and retain Indigenous employees.

Operating Costs for this KBU have remained flat since fiscal 2016. Increases in workload since fiscal 2016 include negotiating and implementing eight relationship agreements with First Nations, and increased involvement of First Nations in BC Hydro's activities where there are potential impacts to their interests. These increases have been resourced by converting external resources to internal employees through the Workforce Optimization Program, which is discussed further in Chapter 5, section 5.6.1.

The primary drivers for the number of FTEs in this KBU are:

- The number of capital projects and how BC Hydro's projects, programs and operations activities interact with First Nations interests;

- The number of agreements with First Nations in development or implementation;
- BC Hydro's ability to attract and retain Indigenous employees in its workforce; and
- Emerging changes in legal requirements and government direction that require changes to our engagement and consultation practices.

5B.5.2.1. Indigenous Relations Director Department

This department includes labour costs for the Director of Indigenous Relations and an administrative assistant. Non-labour costs include funding to support agreements with First Nations, and employee training, travel and expenses.

5B.5.2.2. Regional Relationship and Consultation Departments

The majority of the operating cost budget for the Indigenous Relations' regional departments is related to labour for 42 FTEs. These FTEs charge out 58 per cent of their labour costs directly to capital projects.

These FTEs are organized into three regions and include two primary roles – project leads or relationship leads. The project leads carry out consultation and oversee the implementation of commitments that are made throughout consultation and in project related agreements. The relationship leads facilitate relationships with 54 First Nation communities and develop and implement relationship agreements. Support roles in the regions include public affairs officers, records analysts, and managers.

Collectively, the FTEs in the three regional departments complete the following activities:

- Engagement and consultation on projects;[218]
- Implementation of finalized relationship agreements: BC Hydro has 11[219] finalized relationship agreements with First Nations in implementation; and
- Implementation of Impact Benefit Agreements (**IBAs**): BC Hydro has 14 finalized IBAs with First Nations in implementation.

The remaining non-labour costs in this department include funding to develop and implement agreements with First Nations, and employee training, travel and expenses.

5B.5.2.3. Indigenous Employment, Training and Communications Department

The majority of this department's budget relates to labour costs for eight FTEs. This department charges out 24 per cent of labour costs directly to capital projects.

Collectively, these FTEs complete the following activities:

- Implementation of finalized agreements: BC Hydro has 11 finalized relationship agreements with First Nations in implementation;
- Organize a range of skills building and work experience events with approximately 400 participants;
- Award over 20 provincial scholarships and bursaries across the province; and
- Recruit and manage approximately 20 youth through the annual Youth Hire Program.

[218] Engagement and consultation activities can include: meetings and correspondence with First Nations, coordinating their involvement in project activities such as field work and site visits, and documenting these activities in Indigenous Relations information tracking system.

[219] Includes eight relationship agreements finalized between fiscal 2016 and fiscal 2019, plus BC Hydro's agreements with St'at'imc, Tsay Keh Dene and Kwadacha.

5B.5.2.4. Business Operations and Negotiations Department

The majority of this department's budget relates to labour costs for 12 FTEs. This department charges out 43 per cent of their labour costs directly to capital projects.

Collectively, these FTEs complete the following activities:

- Tracking, quality control and reporting of finalized agreements with First Nations in implementation: BC Hydro has 11 finalized relationship agreements in implementation;
- Consultation adequacy assessments: approximately 100 consultation adequacy assessments for BC Hydro projects; and
- Project screening for First Nations interests: approximately 150 project screens for impacts to First Nations interests.

5B.5.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5B-7 Indigenous Relations KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.2 L2	6.1	7.3	6.1	6.1	6.1	6.3	6.1	6.3
2	FTEs	16.0 L10	47	57	47	59	47	69	69	69

Operating costs are decreasing by approximately $0.2 million from the fiscal 2019 forecast to the fiscal 2020 plan due to vacancy factor savings, which are discussed further in Chapter 5, section 5.5.2.3. The vacancy factor savings are partially offset by Standard Labour Rate increases. Operating costs are increasing by approximately $0.2 million from the fiscal 2020 plan to the fiscal 2021 plan due to Standard Labour Rate increases. FTEs are planned to remain constant.

The increase in FTEs from the fiscal 2019 RRA to fiscal 2019 forecast was primarily driven by the Workforce Optimization Program, described in Chapter 5, section 5.6.1.

5B.6 Environment

5B.6.1 Responsibilities

The Environment KBU's role is to provide a consistent company-wide approach to environmental management and governance. BC Hydro's infrastructure has a significant footprint on the landscape of British Columbia. Therefore, it is important that we build and operate our system in an environmentally responsible way.

The Environment KBU enables BC Hydro to build projects and operate in compliance with environmental requirements and in line with our regulatory and other commitments. Examples of our regulatory commitments include the:

- Water Licence Requirements Program associated with Water Use Plans;
- Fish & Wildlife Compensation Program;
- Fish Entrainment Strategy Program; and
- Williston Dust Management Program.

This KBU creates and implements policies, standards and procedures to avoid, minimize or mitigate impacts to the environment resulting from BC Hydro's capital projects and operations. The KBU manages a risk review process so that environment and related risks are systematically considered and addressed in decision making.

A company-wide Statement of Environmental Principles provides environmental guidance to all staff and contractors to ensure that actions and decisions made in delivering work are aligned with BC Hydro's compliance and regulatory requirements and our responsibility to respect the environment.

There have been no material changes to the responsibilities of this KBU since the Previous Application.

The Environment KBU consists of the following departments:

- Project Environmental Risk Management, Regulatory and Policy Department;
- Environmental Field Operations Department;
- Land Program Department;
- Water Program Department; and
- Fish & Wildlife Compensation Program Department.

5B.6.1.1. Project Environmental Risk Management, Regulatory and Policy Department

This department provides environmental services for the planning and execution of hundreds of generation, transmission, distribution and properties capital projects and programs in various phases of delivery. The department's role includes oversight of environmental compliance and risk management, and management of environmental and heritage components of projects including contract management. This department tracks environmental regulatory changes and prepares BC Hydro for new regulatory and compliance requirements.

This department also helps capital projects receive required environmental permits and authorizations, works with regulators to provide ongoing progress updates and management of project related issues, and facilitates understanding of future legislative requirements by providing information in advance and throughout BC Hydro, on regulatory changes.

5B.6.1.2. Environmental Field Operations Department

Through regionally based teams, the Environment Field Operations department services day-to-day environmental compliance requirements associated with operations and related Power System infrastructure in the field. For example, this department:

- Provides environmental instructions used by field crews for pole replacements;

- Implements environmental field responses to minimize impacts to fish resulting from generating station operating or maintenance activities;
- Ensures that field crews are trained in environmental requirements and responses to risks such as oil spill cleanup and hazardous waste management; and
- Provides emergency after-hours stand-by support to manage incidents and mitigate impacts (e.g., pole-top transformers oil spills from storm event damage).

This department works to achieve operational environmental compliance by developing work practices that fulfill compliance requirements. This is done by combining identified field needs with expert advice from the Land Program department, discussed in section 5B.6.1.3 and the Water Program department, discussed in section 5B.6.1.4. This department works directly with managers and crews in the field to implement environmental practices and to obtain local permits required for work. This avoids maintenance delays and possible enforcement action by environmental regulators.

In addition, this department is responsible for improving environmental performance by setting company-wide objectives and targets, monitoring and reporting on performance, and initiating preventive and corrective actions for environmental incidents. This department is also responsible for the Williston Dust Mitigation Program.

5B.6.1.3. Land Program Department

This department manages land-based environmental impacts and compliance requirements by developing corporate environmental standards[220] and providing expert advice and service to avoid or address land-based environmental risks. This

[220] Examples of Land Program corporate standards include the Sulphur Hexafluoride (SF_6) Environmental Standard, the Contaminated Sites Environmental Standard, and Management of Materials Containing PCB: WM-310.

department works to ensure that Project Environmental Risk Management, Regulatory and Policy and Environmental Field Operations departments are provided with effective standards for capital asset planning, capital projects, field programs and operational needs. This department manages programs in areas such as contaminated sites, pollution prevention, spill response, wildlife ecology and mitigation, archaeology and heritage, as well as greenhouse gas reporting and climate change mitigation.

5B.6.1.4. Water Program Department

This department manages water-based environmental impacts and compliance requirements by developing corporate environmental standards[221] and providing expert advice and service to avoid or address water-based environmental risks. In parallel with the Land Program department, this department works to ensure that the Project Environmental Risk Management, Regulatory and Policy department and the Environmental Field Operations department are provided with effective standards for all planning, project, program and operational needs for water-based subjects. This department delivers the Water Licence Requirements program, as well as programs and strategies to address legislative and regulatory requirements related to fish passage, fish entrainment,[222] total dissolved gas[223] and invasive aquatic species.

This department is responsible for keeping BC Hydro in compliance with the regulatory requirements of our *Water Sustainability Act* Orders, Water Licence conditions and *Fisheries Act* Authorizations to mitigate our impacts. By remaining compliant with these permits and authorizations, and through related regulatory agreements, we have been able to develop and implement actions that provide us with our regulatory licence to operate.

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[221] An example of a Water Program corporate standard is the Approved Work Practices for Boat Launch Construction and maintenance of BC Hydro Managed Freshwater Systems

[222] Fish entrainment refers to fish diverted downstream through a man-made structure (usually a spillway, low level outlet, penstock or turbine) often with resulting harm.

[223] Total dissolved gas refers to the sum of gases in water expressed as a per cent of relative atmospheric pressure. Gas bubble trauma in fish occurs when total dissolved gas escapes bodily fluids as bubbles causing physical damage.

5B.6.1.5. Fish & Wildlife Compensation Program Department

BC Hydro has water licence compensation obligations in the Columbia and Peace regions to address the historical impacts to fish and wildlife associated with the construction of the dams. BC Hydro has made voluntary commitments to address similar impacts in the Coastal Region. These obligations are met through the work of the Fish & Wildlife Compensation Program. This department implements the project decisions of the program's three regional boards, which include representation from the Government of B.C., Fisheries and Oceans Canada, First Nations, public stakeholders and BC Hydro.

This department facilitates multi-party collaboration, decision making and compensation in watersheds where BC Hydro has a significant presence. This department ensures BC Hydro is able to comply with its Water Licence conditions for Columbia and Peace operations.

5B.6.2 Overview of Operating Costs and FTEs

Table 5B-8 Environment KBU
Fiscal 2019 Forecast Operating Costs
and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Director, Environment	0.2	0.0	0.0	0.0	0.0	0.0	0.0	**0.2**	(4)
2	Project Env Risk Mgmt, Reg and Policy	1.1	0.0	0.4	0.0	0.0	0.0	0.0	**1.5**	22
3	Environment Field Operations	3.9	0.0	4.2	0.0	0.0	0.0	0.0	**8.2**	34
4	Land Program	1.5	0.0	1.7	0.0	0.1	0.0	0.0	**3.4**	14
5	Water Program	2.6	0.0	17.9	0.0	0.0	0.0	-13.7	**6.8**	19
6	Fish & Wildlife Compensation Program	0.2	0.0	9.0	0.0	0.0	0.0	0.0	**9.2**	5
7	**Total (Sch 5.2 L3, Sch 16.0 L11)**	**9.5**	**0.0**	**33.1**	**0.1**	**0.1**	**0.0**	**-13.7**	**29.2**	**89**

The Environment KBU's operating costs and FTEs are primarily driven by three requirements:

- Overseeing environmental compliance across projects and operations;
- Delivering our regulatory commitments through programs such as the Water License Requirements and the Fish & Wildlife Compensation Program; and

- Providing input to and working with the Indigenous Relations KBU to increase First Nations participation in environmental components of projects, operations and programs.

In fiscal 2019, approximately 28 per cent of labour costs in this KBU were charged to capital and work programs and are not included in the labour costs provided in Table 5B-8 above. External recoveries (explained in section 5B.6.2.5) offset approximately 32 per cent of the operating costs in this KBU.

The Environment KBU's primary approach to work plan delivery is to retain an in-house oversight role and to contract on-the-ground requirements, such as environmental monitoring. The Environment KBU applies a consistent approach to evaluate and determine FTE and contractor requirements. This approach involves:

- Assessing the workload volume, complexity, and risk associated with capital projects and operations, and work plans to deliver environmental programs;
- Assessing current resource requirements in comparison with historic records or through expert assessment of requirements;
- Assigning work component resource estimates to internal staff, based on their expertise, experience and available time;
- Considering other options when FTE availability is insufficient to meet demands including the use of short term contractors to augment peaks in workload; and
- Monitoring delivery performance by tracking measures such as overtime, contractor spending patterns and milestone delivery and then modifying or reassigning resources as required to address priorities and improve delivery.

5B.6.2.1. Director, Environment Department

This department contains the labour costs for the Director of the Environment KBU and an administrative assistant, as well as vacancy factor savings, which are discussed further in Chapter 5, section 5.5.2.3.

5B.6.2.2. Project Environmental Risk Management, Regulatory and Policy Department

This department consists of 22 FTEs who charge out 76 per cent of their labour costs to capital projects. The majority of these FTEs are environmental professionals who provide capital project support.

Overall, this department is responsible for providing environmental work package requirements for approximately 450 Power System capital projects, Properties capital projects, and Distribution capital projects and programs each year. This means that each FTE in this department oversees work package requirements for approximately 20 capital projects.

In addition, this department provides environmental training to 24 teams throughout different KBUs in the organization each year, and reviews the requirements of and changes to six major federal acts, eight provincial acts, and over 100 regulations and related documentation, as well as maintains documentation for 22 *Fisheries Act* Authorizations.

This department's non-labour costs of $0.4 million fund professional and safety training and the delivery of post-project environmental commitments,[224] such as environmental permit conditions that extend beyond project completion.

5B.6.2.3. Environmental Field Operations Department

This department consists of 34 FTEs who provide the following key deliverables:

- Working directly with Operations managers and crews to implement best practices for fish and fish habitat, wildlife, archaeology and heritage sites and pollution prevention to meet compliance requirements and to avoid or minimize operational impacts to land, air and water;

[224] Examples of post-project commitments include compensation habitat construction, re-vegetation monitoring, fisheries compensation monitoring and other site restoration monitoring.

- Providing 24/7 emergency response to events such as fires, floods and oil spills from overhead and underground transformers and substation equipment;
- Developing and delivering environmental training to over 2,000 field staff through more than 170 annual sessions; and
- Conducting approximately 15 environmental compliance evaluations and 85 environmental observations (assessments to check procedures are followed) annually as well as investigating all significant incidents and developing corrective actions (16 investigations were conducted in fiscal 2018).

This department's non-labour costs of $4.2 million include $2.7 million for the Williston Dust Management Program.[225] The remainder supports reservoir fertilization, debris management, post-project and other monitoring, educational materials development, environmental compliance evaluations, and professional and safety training.

5B.6.2.4. Land Program Department

This department consists of 14 FTEs who provide the following key deliverables:

- Subject area expertise (i.e., pollution prevention, archaeology and heritage, wildlife, and greenhouse gas reporting), and development of corporate standards, programs,[226] procedures,[227] and environmental screening tools;[228]
- Compliance with Federal and Provincial pollution prevention regulations and reporting, and coordination of the Contaminated Sites Management Program with an inventory of 400 sites and active management of 30 contaminated properties; and

[225] The Williston Dust Management Program is a Contribution Agreement with the Tsay Keh Dene Nation to address air quality issues. The Tsay Keh Dene Nation conducts work that reduces the impact of dust emissions from the drawdown zone on their communities when the reservoir level is low.

[226] A corporate program example is the Contaminated Site Management Program.

[227] Some corporate procedure examples include the Oil Leak Identification and Mitigation, and the Procedure – Managing Cultural Heritage and Archaeological Risk on Capital Projects.

[228] A screening tool example is Indigenous Relations-Environment Integrated Screening Tool for Programs.

- Development of Cultural Heritage Information Plans, and delivery of the multi-year Reservoir Archaeology Program for 26 reservoirs to comply with and meet commitments under the B.C. *Heritage Conservation Act* and to provide support for First Nations relationships and agreements.

This department's non-labour costs of $1.7 million support the Reservoir Archaeology Program, Cultural Heritage Information Plans, pollution prevention compliance actions, wildlife compliance, greenhouse gas reporting and professional and safety training.

5B.6.2.5. Water Program Department

This department consists of 19 FTEs who provide the following key deliverables:

- 22 Water Use Plan orders and the associated 350 monitoring studies and physical works necessary for compliance under BC Hydro's Water Licences; and
- *Fisheries Act* Authorization requirements at 30 BC Hydro facilities, as well as other regulatory requirements and commitments including the Fish Passage Framework, Fish Entrainment Strategy responses at 15 facilities with high entrainment risks and the Invasive Aquatic Species program.

This department's non-labour costs of $17.9 million provides funding to deliver the Water License Requirements program as ordered by the Comptroller of Water Rights, and other regulatory commitments. The majority of these costs are offset by external recoveries, which totalled $13.7 million in fiscal 2019. External recoveries capture reimbursement of expenses credited against annual B.C. provincial water rental fees paid by BC Hydro. These Water Use Planning Remissions recoveries result when additional expenses are incurred as a result of projects or constraints ordered by the Comptroller of Water Rights and were not originally contemplated in BC Hydro's Water Licences (for further information see Chapter 4, section 4.6.5). The remaining costs not covered by external recoveries primarily support

Comptroller of Water Rights ordered projects which are not remissible, and support regulatory commitments to fisheries and invasive species programs.

5B.6.2.6. Fish & Wildlife Compensation Program Department

This department consists of five FTEs who manage all aspects of the Fish & Wildlife Compensation Program on a regional basis. The labour costs associated with regional managers are charged to the regional programs and are not captured in the labour costs for this department.

The Fish & Wildlife Compensation Program Department's fiscal 2019 forecast of $9.2 million includes $5.3 million for the Columbia region, $2.1 million for the Coastal region, $1.5 million for the Peace region and $ 0.2 million for management costs. Management costs include management labour, department training and other expenses of the department manager.

This department's budget fulfills BC Hydro's obligation to the Fish & Wildlife Compensation Program's three regions. The program and regional budgets are based on historical agreements negotiated with regulators. These agreements provide the three regions with annual funding increases tied to the Consumer Price Index and allow for any annual under spend to be carried forward to subsequent years.

5B.6.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5B-9 Environment KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.2 L3	27.2	26.2	27.5	27.0	27.8	29.2	29.8	30.0
2	FTEs	16.0 L11	83	86	83	90	83	89	94	94

Operating costs are increasing by approximately $0.6 million from the fiscal 2019 forecast to the fiscal 2020 plan due to an increase in Fish & Wildlife Compensation Program funding, additional Water Licence Requirements and Standard Labour Rate increases. Operating costs are increasing by approximately $0.2 million from the fiscal 2020 plan to the fiscal 2021 plan due to Standard Labour Rate increases.

FTEs are planned to increase by five from the fiscal 2019 forecast to the fiscal 2020 plan due to the Workforce Optimization Program, which is discussed further in Chapter 5, section 5.6.1. FTEs are planned to remain constant from the fiscal 2020 plan to the fiscal 2021 plan.

The increase in FTEs from the fiscal 2019 RRA to the fiscal 2019 forecast was primarily driven by the Workforce Optimization Program, as discussed in Chapter 5, section 5.6.1.

5B.7 Properties KBU

5B.7.1 Responsibilities

The Properties KBU is responsible for BC Hydro’s property and real estate assets province-wide and provides related expertise and services across BC Hydro to support operations and capital projects. This includes over 74,000 acres of land, made up of over 4,000 individual land parcels as well as extensive statutory rights of way in support of 86,000 kilometres of distribution and transmission lines and Crown land tenures for 26 generation reservoirs and 81 dams. In addition, BC Hydro’s corporate headquarters and field buildings total approximately three million square feet in size. The size, scope, complexity and importance of BC Hydro’s property and real estate interests to our operations and projects drives the main functions of the Properties KBU, which include:

- Managing existing property rights for BC Hydro’s Power System infrastructure (transmission and distribution lines, substations, reservoirs, dams, powerhouses, access roads);
- Managing the acquisition of land and property rights to facilitate the upgrades and expansion of the Power System and field facilities;

- Managing property leases and licences, and sales of surplus property;
- Developing asset management and capital plans for the 101 BC Hydro headquarters and field buildings that make up the Properties' managed building portfolio;[229]
- Managing the delivery of building replacement and upgrade capital projects for BC Hydro's headquarters and field buildings; and
- Operating and maintaining BC Hydro's headquarters and field buildings that house approximately 6,000 BC Hydro employees and contractors who work from these facilities. Services provided to support operations across the province also include work space planning and work location moves and mail distribution.

There have been no material changes to the responsibilities of the Properties KBU since the filing of the Previous Application with the exception of the addition of the mail services function, transferred to the Properties KBU as part of the Accenture Repatriation, which is discussed further in Chapter 5, section 5.6.2.

The Properties KBU is organized into the following departments:

- Real Estate Planning and Project Delivery Department;
- Facilities and Space Management Department;
- Property Rights Management Department; and
- Real Estate Services Department.

5B.7.1.1. Real Estate Planning and Project Delivery Department

The Real Estate Planning and Project Delivery department is responsible for long term and capital planning for BC Hydro's property and real estate assets, managing

[229] Facilities that house the Power System infrastructure (i.e., substations, generating stations) are the responsibility of the Integrated Planning Business Group and the Operations Business Group and are outside the portfolio managed by the Properties KBU, given the specific safety and operational requirements for the electrical assets.

capital project delivery, and delivering property information management services. This includes:

- Long-term planning and forecasting for BC Hydro's corporate and field office real estate across British Columbia, including properties surplus to BC Hydro's needs;
- Developing and managing the capital investment plans for the Properties' managed building portfolio. The department manages the asset (facility components) information, including asset condition and age, in order to identify those assets that are in need of replacement or refurbishment, and develops the prioritised capital plan to address these needs. Proactively identifying and planning for the replacement of building assets avoids the additional costs and operational disruption associated with completing emergency repairs and replacements;
- Executing the Properties' capital plan, through project delivery oversight, ensuring projects are completed to schedule and budget, meeting BC Hydro business needs and standards as well as regulatory, environmental, safety and building code requirements. The department establishes the construction and product standards for BC Hydro's buildings and determines the construction methodology. While this department completes the assessment of operational business needs, sets the standards and engages with key stakeholders, construction work is undertaken by external construction companies. In addition, the majority of projects are managed by contract project managers with experience in industrial building construction project delivery. The department's delivery of building renovation and development projects ensures that BC Hydro's operations are housed in safe, secure and seismically resilient facilities; and
- Maintaining the physical and electronic records for the entire portfolio of BC Hydro's property interests through a centralized information system. This

system captures key property information for every land parcel that BC Hydro owns (e.g., legal documents such as purchase and sale agreements, Right-of-Way agreements, leases and licences and facilities asset information). This database supports BC Hydro's oversight and management of its property interests in support of capital projects and operations.

5B.7.1.2. Facilities and Space Management Department

The Facilities and Space Management department is responsible for the maintenance and operations of BC Hydro's 101 field and office facilities, and provides business services and workspace management services (including workstation design, physical moves, and space reconfigurations) for BC Hydro's operations across the province. This includes:

- Ensuring buildings and facilities assets are efficiently operated, maintained and repaired to meet BC Hydro's expectations and needs, including business continuity (24/7 emergency response) as well as environmental, health, and safety standards. To achieve these outcomes BC Hydro contracts with a single outsourced provider for the larger facilities and multiple service providers for the smaller and more remote facilities. This department provides contract management and oversight as BC Hydro's representative and also plays an important role overseeing the interface between building occupants and contractors;
- Managing the operations and maintenance of facilities across the province. This centralized approach allows for coordinated and standardized maintenance, and investments across the facilities. If the facility component assets are not maintained, their deterioration would impact worker health and safety, productivity, emergency response capability and components would need to be replaced more often, increasing overall asset life cycle costs;
- Coordinating workspace moves for the majority of BC Hydro employees and contractors. This department ensures that work space designs and

reconfigurations maximize space usage and use standardized layouts and furniture to allow for maximum flexibility and reduced costs while meeting all code requirements for access and egress; and

- Sorting and distributing internal and external mail across all occupied BC Hydro facilities as well as managing the contracts for province-wide courier services, food services, and parkade management.

5B.7.1.3. Property Rights Management Department

The Property Rights Management department manages BC Hydro's property rights and interests over Crown, First Nations[230] and private lands, fulfilling an important support role that enables BC Hydro to reliably and safely operate, access and maintain our dams and reservoirs, generation facilities, and transmission and distribution systems. This includes:

- Working directly with land owners to secure BC Hydro's rights to access their land, access BC Hydro owned infrastructure, undertake our maintenance work, such as vegetation management, or to construct new infrastructure;
- Managing all interactions with third parties, such as land owners, community groups, municipalities and pipeline companies, who request use of or access through BC Hydro land and rights-of-way. These secondary use requests must be compatible with BC Hydro's operational, safety and security requirements, given the risk of damage, electrical safety and related liabilities; and
- Providing subject matter expertise to represent BC Hydro's interests during the Government of B.C.'s proposed Crown land dispositions with First Nations for Treaty Settlements or other government agreements. This representation is critical so that our rights to continue to operate our existing Power System on First Nations lands are maintained, and so that rights are in place for future lines and reservoir operations.

[230] First Nations lands include First Nations Reserve, Treaty, and Title Lands.

5B.7.1.4. Real Estate Services Department

The Real Estate Services department acquires land and property rights for BC Hydro's development of the Power System and field facilities, conducts surplus property sales, manages property leases and licences, and administers BC Hydro's property tax portfolio. This includes:

- Undertaking the acquisition of land and property rights for BC Hydro's capital projects, customer interconnection projects, and BC Hydro field facility development projects;
- Managing rights acquisition agreements in support of new distribution system connections across the province. The timely and legal acquisition of suitable property interests is necessary to enable BC Hydro to access and occupy sites as well as construct, operate and maintain system assets;
- Managing BC Hydro's surplus property sales including ensuring all due diligence, legal, environmental clearances and First Nations consultation activities are completed prior to property sales. This department has a target of achieving net sales of $100 million by the end of fiscal 2024, an important contribution to maintaining affordable rates, through sales proceeds and reduced holding costs on surplus properties. Variances between planned and actual surplus property sales are captured by the Real Property Sales Regulatory Account, which is discussed further in Chapter 7, section 7.8.7;
- Managing all property leasing and licencing agreements, representing BC Hydro as landlord for BC Hydro owned property and as a tenant for leased space. Leased space is required in various locations across the province to supplement owned space that may be at capacity, to provide short term space for project teams, or in locations where BC Hydro does not own facilities. Licence agreements relate to revenue-generating secondary use of and access to BC Hydro property (e.g., telecommunications infrastructure and film set locations); and

- Managing BC Hydro's property tax assessments and ensuring that BC Hydro is compliant with regulations to pay taxes and grants. BC Hydro is one of the largest property tax payers in the province with an annual property tax bill (Grants in Lieu and School Taxes) of approximately $250 million on assets assessed at over $11 billion. Given the significant size of this obligation, the department identifies opportunities to reduce current and future tax assessments. For example, in fiscal 2018 and fiscal 2019, combined annual savings of over $3 million were achieved through negotiations and appeals that will be reflected in reductions in future years' assessments.

5B.7.2 Overview of Operating Costs and FTEs

Table 5B-10 Properties KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Properties Director's Office	0.4	0.0	0.0	0.0	0.0	0.0	0.0	**0.4**	2
3	Real Estate Planning and Project Delivery	1.0	0.0	1.0	0.1	0.1	0.0	0.0	**2.3**	21
4	Facilities and Space Management	2.5	0.1	16.8	0.7	6.6	0.0	0.0	**26.7**	30
2	Property Rights Management	1.2	0.0	0.1	0.0	0.0	0.0	0.0	**1.3**	31
5	Real Estate Services	1.6	0.0	0.4	0.0	0.0	0.0	0.0	**2.0**	40
6	**Total (Sch 5.2 L4, Sch 16.0 L12)**	**6.7**	**0.1**	**18.3**	**0.8**	**6.7**	**0.0**	**0.0**	32.7	**124**

Overall, operating costs for the Properties KBU have decreased by $0.6 million since fiscal 2016, despite an increase in labour costs of approximately $1.0 million due to the repatriation of Accenture roles, the conversion of Facilities Management service provider contractors to internal staff and the increased FTEs required to manage higher work volume and complexity.

Approximately 48 per cent of the KBU's total labour costs are charged to projects and not included in this KBU's operating cost budget. The remaining 52 per cent of labour costs make up 20 per cent of the total operating costs for the Properties KBU.

Non-labour costs in the Properties KBU consist primarily of costs paid to contractors to manage and maintain the facilities. These costs have increased by $2.4 million since fiscal 2016 due to the transfer of five buildings to the Properties-managed portfolio, the substantial expansion of three buildings within the portfolio, and inflationary cost escalation associated with the Facilities Management service provider contract.

These increases have been offset by the following reductions:

- $1.7 million in lease cost reductions achieved by not renewing external office space leases and relocating staff into BC Hydro owned buildings through increased space utilization in those buildings;
- $0.9 million in reduced operating costs related to capital projects; and
- $1.4 million in annual operating cost savings related to the Accenture repatriation, which is discussed further in Chapter 5, section 5.6.2.

5B.7.2.1. Properties Director's Office Department

The budget for this department relates to labour costs for two FTEs – the Director of the Properties KBU and an Administrative Assistant.

5B.7.2.2. Real Estate Planning and Project Delivery Department

Approximately 40 per cent of this department's budget is related to labour costs. The 21 FTEs in this department charge approximately 50 per cent of their time to capital projects.

The workforce requirements for this department are mainly driven by the volume and complexity of Properties-managed capital projects as well as the volume of work in other departments in the Properties KBU. The majority of the capital project managers are contracted resources, with oversight provided by internal FTEs in this department. This resourcing approach allows for maximum flexibility as the volume and complexity of capital projects can vary significantly from year-to-year. This department also relies on subject matter experts from other KBUs (e.g., Safety, Environment, Indigenous Relations) to support project delivery.

The Real Estate Planning and Project Delivery department is responsible for:

- Planning for more than 12,000 assets at 101 facilities;
- Delivering an average of 75 property capital projects per year with a total capital budget of approximately $60 million; and
- Managing approximately 140,000 physical records and the creation or transfer of approximately 16,000 files per year.

The non-labour budget for this department is primarily related to operating costs for capital projects such as temporary lease costs and moving costs.

5B.7.2.3. Facilities and Space Management Department

Approximately 70 per cent of this department's budget is related to costs to service BC Hydro's 101 facilities across the province. These facilities comprise approximately 3 million square feet of office and industrial space. Service provider costs include facility services (e.g., janitorial, snow removal/yard sweeping, pest control, landscaping, waste collection services) as well as repairs and maintenance to building components (e.g., plumbing, electrical, overhead doors, fences and gates, generators, HVAC, sprinklers and fire extinguishers). Preventative maintenance is completed on critical building components and work is carefully managed to balance affordability with the reliability and safety of our facilities.

Approximately 20 per cent of this department's budget is related to rent paid to lease facilities. BC Hydro has reduced its lease costs by approximately 25 per cent since fiscal 2016, through the consolidation of lease space and increased utilization of space at BC Hydro owned facilities.

Approximately nine per cent of the Facilities and Space Management department's budget is related to labour for 30 FTEs. This department manages the contract for the single provider of outsourced facility management services, covering approximately 40 per cent of BC Hydro's facilities, and also manages more than

100 vendors who provide services to the remaining 60 per cent of facilities that are managed directly by the department. The department also coordinates workspace moves for BC Hydro employees and contractors. Workspace moves are required for various reasons, including the collapse of leases, renovations and capital projects, new hires and employee transfers. This department also handles more than 500,000 pieces of internal and external mail annually for all of BC Hydro's occupied facilities throughout the province.

As facility operations, maintenance and repair activities are contracted out, the department's size is commensurately small. When workload pressures occur, contractors are used on a short-term or project basis.

5B.7.2.4. Property Rights Management Department

Approximately 90 per cent of this department's budget relates to labour costs for 31 FTEs. The FTEs in this department charge approximately 60 per cent of their labour costs to projects in other KBUs.

The resourcing requirements of this department are driven by the volume and complexity of work requests received including capital projects that require rights acquisitions, secondary use and rights of way access requests by third-parties, as well as First Nations property rights acquisitions and Provincial Treaty settlement negotiations.

This department manages:

- More than 2,600 secondary use requests per year;
- Over 100 property rights acquisitions each year for distribution system connections on First Nations lands;
- Twenty-four current potential First Nations Treaty Settlement land disposition processes; and

- Approximately 7,000 agreements for Generation reservoir and dam related property rights and approximately 84,000 agreements for Transmission and Distribution property rights.

While the number of work requests has remained fairly stable in recent years, the mix and complexity of the requests has increased, adding to the workload of the department. This additional workload is managed through supplementing existing resources with temporary contractors, reassigning resources from other departments in the Properties KBU, and managing backlogs.

5B.7.2.5. Real Estate Services Department

Approximately 80 per cent this department's budget is related to labour costs for 40 FTEs. The FTEs in this department charge approximately two-thirds of their time to projects and programs in other KBUs.

The workforce requirements for this department are mainly driven by the volume and complexity of work activities and transactions processed. For example, the number and scale of capital construction projects that require land or rights acquisitions and the volume of distribution connection requests.

On an annual basis, this department manages approximately:

- 85 Power System capital projects;
- 1,600 distribution system requests;
- 1,200 leasing and licencing agreements;
- 35 active surplus sales processes; and
- 4,000 property tax assessments.

The workforce of this department is sized to deliver services responsively to capital project teams, and other parts of BC Hydro, such as the Distribution Design Customer Connections KBU. When additional resources are required, the department manages resources with planned reliance on overtime, reassigned resources from other departments in the Properties KBU and, in peak times, contractors, to manage workload and backlogs.

The remaining 20 per cent of the department's budget is for contract services and consultant fees including independent appraisals and additional contractor support for complex lease and sales files.

5B.7.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5B-11 Properties KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.2 L4	32.2	32.2	32.5	32.7	32.8	32.7	29.3	29.5
2	FTEs	16.0 L12	106	110	106	114	106	124	123	123

Operating costs are decreasing by approximately $3.4 million from the fiscal 2019 forecast to the fiscal 2020 plan due to IFRS 16 lease standards accounting changes (as described in Chapter 5, section 5.5.2 and Chapter 8, section 8.13), reduction in lease costs through consolidations (discussed in Chapter 5, section 5.5.2.3) and vacancy factor savings (also discussed in Chapter 5, section 5.5.2.3). These savings are slightly offset by Standard Labour Rate increases. Operating costs are increasing by approximately $0.2 million from the fiscal 2020 plan to the fiscal 2021 plan due to Standard Labour Rate increases.

FTEs are planned to decrease by one from the fiscal 2019 forecast to the fiscal 2020 plan due to a transfer of one FTE to the Customer Service KBU.

5B.8 Business Unit Support

5B.8.1 Responsibilities

The Capital Infrastructure Project Delivery Business Unit Support KBU includes the budget for the Office of the Senior Vice-President of Capital Infrastructure Project Delivery.

Since the Previous Application, the budgets for capital project investigation costs, First Nations community payments in lieu of taxation, and dam safety investigation costs have been transferred out of this KBU and into the Business Unit Support KBU within the Integrated Planning Business Group. In addition, capital overhead has been transferred to Capitalized Costs.

5B.8.2 Overview of Operating Costs and FTEs

Table 5B-12 Business Unit Support KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	SVP,Capital Infrastructure Proj Delivery	0.7	0.0	0.1	0.0	0.0	0.0	0.0	**0.8**	3
2	**Total (Sch 5.2 L5, Sch 16.0 L13)**	**0.7**	**0.0**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.8**	**3**

5B.8.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5B-13 Business Unit Support KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.2 L5	0.8	0.7	0.8	0.7	0.8	0.8	0.8	0.9
2	FTEs	16.0 L13	3	3	3	3	3	3	3	3

Operating costs are planned to increase slightly from the fiscal 2019 forecast to the fiscal 2020 and fiscal 2021 plan due to Standard Labour Rate increases.

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Chapter 5C

Operating Costs
Operations Business Group

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5C.1 Introduction - Operations Business Group

Chapter 5C provides and explains in detail the composition of, and rationale for the operating costs of the Operations Business Group. The Operations Business Group is one of six business groups in the organization and is responsible for operating BC Hydro's facilities and assets. It serves as the Operate function of the Plan-Build-Operate-Support model.

The Operations Business Group budget was developed as part of the budgeting process outlined in Chapter 5, section 5.4. The information provided in this Chapter 5C demonstrates the basis for the entirety of the Business Group and KBU budgets, rather than focussing only on incremental cost requirements.

Chapter 5C is organized as follows:

- Section 5C.2 provides an overview of the organization and responsibilities of the Operations Business Group;
- Section 5C.3 provides the operating costs and FTE information for the Operations Business Group as a whole,[231] and
- Sections 5C.4 to 5C.11 provide more detailed information on the responsibilities, cost and FTEs for each KBU within the Operations Business Group. The operating costs and FTE information for each KBU is broken out into two sections[231]
  - Overview of Operating Costs and FTEs – This section explains the starting operating costs and FTEs based on the fiscal 2019 forecast; and
  - Fiscal 2020 and fiscal 2021 Plan Operating Costs and FTEs – This section explains any incremental changes between fiscal 2019 forecast and fiscal 2020 and fiscal 2021 plan.

[231] Please note the amounts presented in the tables in these sections may not add due to rounding.

5C.2 Overview of Operations Business Group Organization and Responsibilities

The Operations Business Group is a new business group, created subsequent to the filing of the Previous Application. It combines the operations functions of the former Transmission and Distribution and Generation Business Groups. The planning functions of these former Business Groups are now included in the Integrated Planning Business Group.

The Operations Business Group consists of the following KBUs:

Business Group	Key Business Unit
Operations	Program and Contract Management Line Field Operations Stations Field Operations Distribution Design Customer Connections Construction Services Generation System Operations Transmission and Distribution System Operations Business Unit Support

The role of the Operations Business Group is to:

- **Safely and Efficiently Execute Work:** Maintenance and smaller scale capital work identified by the Integrated Planning Business Group is directed to the Program and Contract Management KBU of the Operations Business Group for delivery. The Program and Contract Management KBU then develops annual program and project delivery plans and assigns work to the primary delivery groups of the Line Field Operations KBU, Stations Field Operations KBU, Construction Services KBU or external contractors;
- **Connect Customers to the Distribution System:** The Distribution Design and Customer Connections KBU provides design work, project coordination and work packages for new connections of distribution voltage customers (25 kV and under) as well as distribution system improvement and end of life asset replacement programs. The execution of this work is then assigned to the

primary delivery groups of the Line Field Operations KBU, the Construction Services KBU, or external contractors;

- **Operation of the Integrated System to Maximize Overall Value:** The Generation System Operations KBU is responsible for planning the operation of BC Hydro's reservoirs and generation facilities and for integrating other energy resources into those operations to meet BC Hydro's load obligations. The T&D System Operations KBU is responsible for managing the real time operation of the BC Hydro generation, transmission, distribution and telecommunication systems.

Larger and more complex capital projects are implemented by the Project Delivery KBU of the Capital Infrastructure Project Delivery Business Group, discussed in Chapter 5B, section 5B.4.

5C.3 Fiscal 2020 and Fiscal 2021 Plan Operating Cost and FTE Summaries

This section addresses planned operating costs and FTEs for the Operations Business Group. The following are some key points of note with respect to the information provided in Figure 5C-1, Table 5C-1 and Figure 5C-2, Table 5C-2 and Table 5C-3:

- The Line Field Operations KBU, Station Field Operations KBU and Construction Services KBU make up over 60 per cent of the Operations Business Group's operating budget. They are primarily comprised of trades staff, responsible for executing the operations, maintenance and capital work required on BC Hydro's Transmission, Distribution and Generation systems;
- The Operations Business Group makes up 40 per cent of BC Hydro's total FTEs, while only accounting for approximately 30 per cent of the base operating costs. This difference is primarily because large portions of the Operations Business Group's work are charged to the maintenance work

programs that are budgeted in the Integrated Planning Business Group, as well as to capital projects. This is described in further detail within the individual KBU sections in this Chapter 5C; and

- The increase in the Operations Business Group's operating budget from fiscal 2019 forecast to fiscal 2020 plan is largely driven by increases to Storm Restoration costs and to Standard Labour Rates, as discussed further in Chapter 5, section 5.5.2.2.

Planned operating costs for this Business Group are approximately $243.0 million in fiscal 2020 and approximately $246.0 million in fiscal 2021. The operating costs for the Operations Business Group are summarized by KBU in Figure 5C-1. Additional cost details are provided in Table 5C-1 below.

Figure 5C-1 Operations Net Operating Costs by KBU (Fiscal 2020 Plan) ($ million)

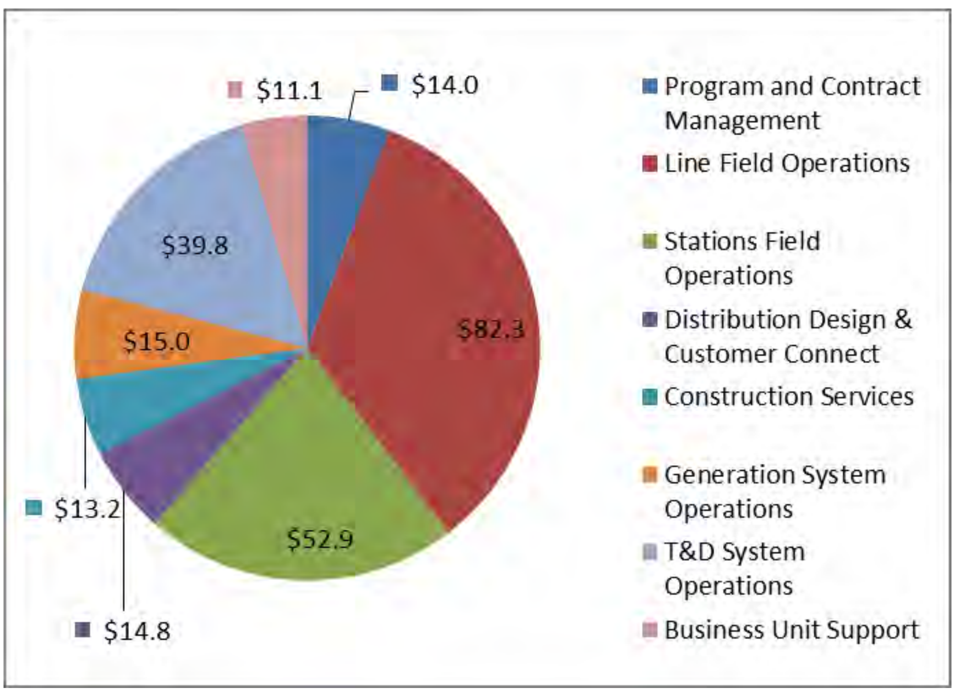

Table 5C-1 Operations Net Operating Costs by KBU

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Program and Contract Management	5.3 L1	13.8	11.6	14.1	11.9	14.3	12.8	14.0	14.2
2	Line Field Operations	5.3 L2	67.7	69.8	68.2	71.6	68.7	68.2	82.3	83.1
3	Stations Field Operations	5.3 L3	41.0	41.5	41.1	39.4	46.9	46.2	52.9	53.5
4	Distribution Design & Customer Connect	5.3 L4	12.8	10.2	13.1	10.6	13.5	14.3	14.8	15.1
5	Construction Services	5.3 L5	13.5	11.4	13.7	12.4	13.9	12.8	13.2	13.3
6	Generation System Operations	5.3 L6	14.5	16.0	14.7	14.2	14.8	14.6	15.0	15.2
7	T&D System Operations	5.3 L7	36.2	38.2	36.7	40.4	37.4	38.3	39.8	40.3
8	Business Unit Support	5.3 L8+L12	6.6	5.4	6.6	6.3	6.7	11.1	11.1	11.3
9	Total	5.3 L15	206.1	204.2	208.2	206.7	216.2	218.4	243.0	246.0

The FTEs for the Operations Business Group are summarized by KBU in Figure 5C-2. Additional details are provided in Table 5C-2 below.

Figure 5C-2 Operations FTEs by KBU (Fiscal 2020 Plan)

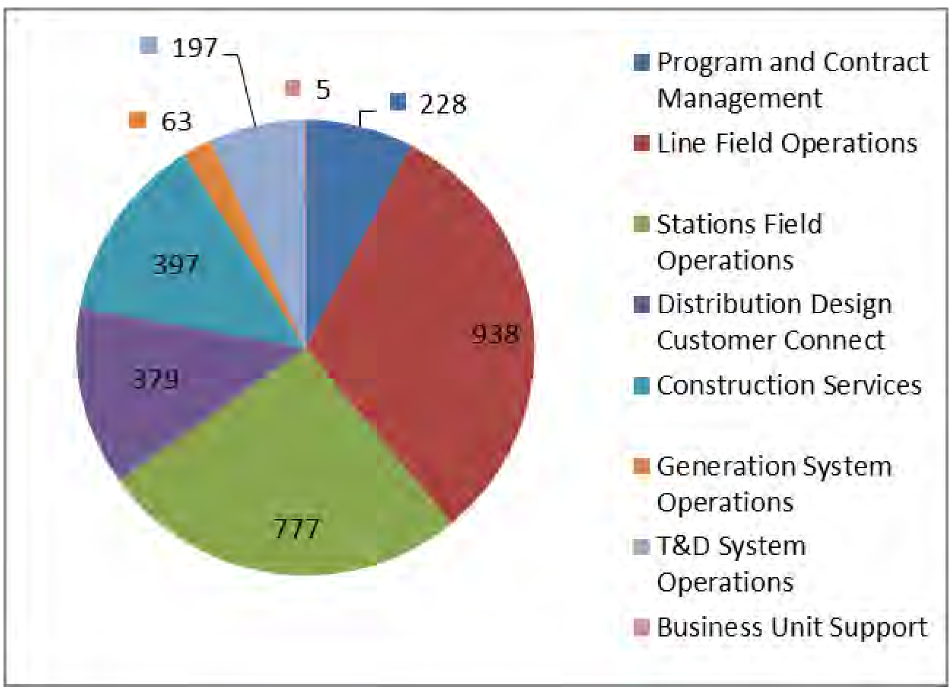

Table 5C-2 Operations FTEs by KBU

	(FTEs)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Program and Contract Management	16.0 L15	213	205	217	206	217	221	228	228
2	Line Field Operations	16.0 L16	844	838	844	856	844	931	938	938
3	Stations Field Operations	16.0 L17	856	829	856	818	856	858	777	777
4	Distribution Design Customer Connect	16.0 L18	338	325	338	347	338	379	379	379
5	Construction Services	16.0 L19	404	411	404	409	404	398	397	397
6	Generation System Operations	16.0 L20	64	65	64	68	64	64	63	63
7	T&D System Operations	16.0 L21	165	170	165	174	165	178	197	197
8	Business Unit Support	16.0 L22	3	3	3	3	3	3	5	5
9	Total	16.0 L23	2,889	2,845	2,893	2,880	2,893	3,033	2,984	2,984

Table 5C-3 below provides a continuity table which highlights changes to the Operations Business Group from the Previous Application. An overall discussion of these changes, at a company-wide level, is provided in Chapter 5, section 5.5.2. Further details, by KBU, are provided in the sections below.

Table 5C-3 Operations Operating Costs Continuity Schedule

	($ million)		F2020 Plan	F2021 Plan
1	F2019 Revenue Requirement Application Plan (Transmission, Distribution and Customer Service)		537.2	
2	Reorganization Impacts		(321.0)	
3	F2019 Revenue Requirement Application Plan (Operations)		216.2	
4	Budget Transfers Between Business Groups		(1.7)	
5	F2019 Waneta 2/3rd Operating Costs (Schedule 5.3, line 12)		3.8	
6	Adjusted F2019 Revenue Requirement Application Forecast (Operations) / carry forward plan (Schedule 5.3, line 15)	A	218.4	243.0
6	Current Year Incremental Waneta 2/3rd Operating Costs	B	1.9	0.2
7	Current Year Budget Transfers Between Business Groups	C	5.7	
8	Test Period Savings			
9	Vacancy factor savings		(0.5)	
10		D	(0.5)	-
11	Test Period Cost Increases			
12	Labour		6.5	2.7
13	Storm Restoration		11.1	
14		E	17.6	2.7
15	Test Period Net Increase/(Decrease)	F=D+E	17.1	2.7
16	Net Operating Costs (Schedule 5.3, line 15)	A+B+C +F	243.0	246.0

5C.4 Program and Contract Management KBU

5C.4.1 Responsibilities

The Program and Contract Management KBU is the single point of contact for the annual delivery of the maintenance and small capital investment portfolio that is developed and optimized by the Integrated Planning Business Group. This KBU is responsible for leading the development of delivery strategies that consider the volumes of work types in each region as well as the forecast internal and external resource capacity to deliver this work. During the test period, the Program and Contract Management KBU will deliver capital projects and programs totalling approximately $650 million and maintenance programs totalling approximately $350 million. More specifically, this KBU:

- **Develops annual program and project plans to deliver work:** Once the annual maintenance and small capital investment portfolio is received from the Integrated Planning Business Group, the Program and Project Managers in the Program and Contract Management KBU develop annual program and project plans to deliver the work in consultation with various KBUs across BC Hydro. Once internal resource commitments to deliver the work are obtained, the Program and Project Managers develop contracting plans to deliver the balance of the annual maintenance and small capital portfolio;
- **Assign work to internal groups and contractors, as appropriate:** Work is assigned to the internal and external Engineering and Design teams and to the field execution teams in Line Field Operations KBU, Stations Field Operations KBU, Construction Services KBU and to external contractors.

  More than half of the work is performed by internal staff. External contractors provide scalability and help respond to fluctuations in demand, including providing support for trouble and storm response work. The KBU seeks external contractors that are cost competitive, and are willing to work collaboratively through longer term relationships with BC Hydro. Contractors are identified through a competitive tendering process, with Program and Contract Management providing centralized management throughout the life of each contract;

- **Monitor progress and adjust as required:** On a monthly and quarterly basis, the Program and Project Managers monitor the progression of the program and project plans, manage change controls, manage external contractor performance and adjust work allocations to the field execution teams as necessary. The Program and Project Managers complete program and project Completion Reports annually or at the end of multi-year programs; and
- **Shares accountability for delivery of Power System capital:** The Program and Contract Management KBU is one of three KBU's accountable for the delivery of the Power System capital projects. The other KBUs responsible for delivering these projects are the Project Delivery KBU (discussed in Chapter 5B, section 5B.4) and the Distribution Design and Customer Connections KBU (discussed below in section 5C.7). Specifically, Program and Contract Management is responsible for delivering smaller scale system improvement projects and less complex capital projects, typically with a forecast capital cost of less than $1 million. Approximately 26 per cent of the planned capital investments in the Power System in fiscal 2020 to fiscal 2021 will be delivered by the Program and Contract Management KBU.

There has been one material change to the responsibilities of this KBU since the Previous Application. The Portfolio Services department of the former Asset Investment Management KBU, is now part of the Program and Contract Management KBU.

Program and Contact Management consists of the following departments:

- Portfolio Services Department;
- Transmission Capital and Maintenance Programs Department;
- Vegetation Management Department;
- Distribution Capital Projects Department;

- Distribution Program Delivery Department;
- Distribution Contract Management Department; and
- Distribution Contract and Operations Management Services (**D COMS**) Department.

5C.4.1.1. Portfolio Services Department

The Portfolio Services department provides scheduling, costing, and systems support to the delivery teams in Program and Contract Management.

Portfolio Services is responsible for forecasting operations labour and equipment resource demand and assessing any resourcing risk to the capital and operating and maintenance plans. The department also facilitates the development of mitigating strategies for the risk. These responsibilities balance two objectives: providing sufficient labour and equipment to execute planned work and optimizing planned use of resources for overall productivity, safety, and quality over both the short and long-term.

5C.4.1.2. Transmission Capital and Maintenance Programs Department

The Transmission Capital and Maintenance Programs department provides program and project management for the delivery of less complex transmission capital projects (typically less than $1 million) and repetitive maintenance and capital programs on transmission infrastructure. This includes transmission conductor lines, underground and submarine cables, steel towers, wood poles and all facilities within a substation as well as the telecommunication system. A key responsibility of the department is to coordinate the allocation of work between BC Hydro’s internal workforce and external contractors.

5C.4.1.3. Vegetation Management Department

The Vegetation Management department is responsible for the execution of all vegetation and access management on the transmission and distribution systems. This work includes:

- Transmission, substation, and distribution vegetation management maintenance programs as well as right of way access maintenance programs;
- Vegetation management, right of way clearing, and access management planning as well as construction in support of transmission and distribution capital projects;
- Storm response to aid in the removal of vegetation to reduce overall system restoration time; and
- Management of the contracts and relationships with vegetation management and access contractors.

5C.4.1.4. Distribution Capital Projects Department

The Distribution Capital Projects department delivers smaller scale system improvement projects and less complex distribution capital projects from the definition phase through to the implementation phase.

The distribution projects portfolio is made up of:

- Growth projects to provide increased system capacity;
- Sustainment projects that improve reliability;
- Distribution interconnection projects; and
- Distribution submarine cable projects.

5C.4.1.5. Distribution Program Delivery Department

The Distribution Program Delivery department is responsible for the management of high volume and repetitive distribution electrical equipment maintenance and replacement delivery programs. This equipment includes the conductor lines, underground cables, support structures such as wood poles, platforms, concrete poles, and associated equipment. A key responsibility of the department is to coordinate the allocation of work between BC Hydro's internal workforce and external contractors.

5C.4.1.6. Distribution Contract Management Department

The Distribution Contract Management department is responsible for contracting electrical and distribution line work to third-parties.

The department undertakes the following work related to external contracting:

- Pre-qualifying contractors to bid on BC Hydro work;
- Coordinating work allocation between various groups that execute the work, evaluating and awarding work packages, and onboarding contractors;
- Acting as the BC Hydro representative on contracts and providing change order management, customer contact and issues management, outage management and coordination, materials coordination, and coordination with the Distribution Design department; and
- Providing supplier relationship management including authorizing contractor employees to work on the BC Hydro system, providing quality management of work completed and ensuring corrective actions are taken as needed.

5C.4.1.7. Distribution Contract and Operations Management Services (D COMS) Department

D COMS is responsible for civil inspection and survey activities as well as inspections of work completed by internal crews and external line contractors to confirm that structures are built to engineering standards and that the quality of construction is acceptable. This department also supports the delivery of distribution maintenance programs and manages external contractors who deliver civil inspection, surveying, engineering and design services. Contract administration support for these activities is provided by the Distribution Contract Management Department, described above.

5C.4.2 Overview of Operating Costs and FTEs

Table 5C-4 Program and Contract Management KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Program and Contract Mangement	0.6	0.0	0.2	0.0	0.0	0.0	0.0	**0.8**	4
2	Portfolio Services	1.3	0.0	0.0	0.0	0.0	0.0	0.0	**1.4**	24
3	Trans Capital and Mtce Programs	0.7	0.0	0.0	0.0	0.0	0.0	0.0	**0.8**	14
4	Vegetation Management	3.0	0.0	0.3	0.1	0.1	0.0	0.0	**3.5**	66
5	Distribution Capital Projects	0.5	0.0	0.0	0.0	0.0	0.0	0.0	**0.5**	16
6	Distribution Program Delivery	1.4	0.0	0.1	0.0	0.0	0.0	0.0	**1.5**	21
7	D Contract Management	2.9	0.0	0.1	0.0	0.0	0.0	0.0	**3.0**	34
8	D COMS	1.2	0.0	0.1	0.0	0.0	0.0	0.0	**1.4**	42
9	**Total (Sch 5.3 L1, Sch 16.0 L15)**	**11.6**	**0.0**	**0.9**	**0.1**	**0.2**	**0.0**	**0.0**	**12.8**	**221**

The number of FTEs in the Program and Contract Management KBU reflect the labour requirements to deliver the maintenance, capital programs and capital projects assigned by the Integrated Planning Business Group. The budget for this work is held by the Integrated Planning Business Group.

From fiscal 2016 to fiscal 2019, total operating costs for this KBU have remained relatively constant.

From fiscal 2016 to fiscal 2019, the total FTEs in this KBU increased by 30 FTEs from 191 FTEs to 221 FTEs. The increase in FTEs was due to the conversion of contractors to employees through the Workforce Optimization Program which is described in Chapter 5, section 5.6.1.

5C.4.2.1. Director, Program and Contract Management Department

The majority of this department’s budget is related to labour. This represents four FTEs: a Director, a Senior Program Manager, a Human Resources Advisor (seconded 100 per cent to Columbia Hydro Constructors Ltd.) and an administrative assistant.

The $0.2 million in non-labour costs for this department represents funding for travel costs and annual dues.

5C.4.2.2. Portfolio Services Department

The majority of this department budget is related to labour. This represents 24 FTEs including: one Department Manager, six Resource Strategy and Management Advisors/Specialists, one Program Technologist Manager and 15 Program Technologists. One FTE represents overtime which is driven by peak demand.

5C.4.2.3. Transmission Capital and Maintenance Programs Department

The majority of this department's budget is related to the labour. This represents 14 FTEs including: one Department Manager, three Program Managers and 10 Work Package Managers. The FTEs are supplemented by 10 external Work Package Managers during peak times.

5C.4.2.4. Vegetation Management Department

The majority of this department's budget is related to labour. This represents 66 FTEs including: one Department Manager, 11 Regional & Program Managers, seven Vegetation Specialists and Foresters, 33 Vegetation Coordinators and five Administrators. Nine FTEs that represent overtime which is driven by peak demand.

The $0.3 million in non-labour costs for this department represents travel costs, annual dues, employee training and office supplies.

5C.4.2.5. Distribution Capital Projects Department

The majority of this department's budget is related to labour. This represents 16 FTEs including: one Department Manager, five Program Managers and 10 Work Package Managers. The FTEs are supplemented by seven external Work Package Managers during peak times.

5C.4.2.6. Distribution Program Delivery Department

The majority of this department's budget is related to labour. This represents 21 FTEs including: one Department Manager, three Program Managers, five Work Package Managers, one Resource Planning Manager and 10 Distribution Maintenance Analysts. One FTE that represent overtime which is driven by peak demand. Due to high workload, this team is supplemented by five external Work Package Managers during peak times.

5C.4.2.7. Distribution Contract Management Department

The majority of this department's budget is related to labour. This represents 34 FTEs including eight Contract Managers, one Business Operation Manager, four Line Field Representatives and 19 Service Contract Administrators. Two FTEs that represent overtime which is driven by peak demand.

5C.4.2.8. Distribution Contract and Operations Management Services (D COMS) Department

The majority of this department's budget is related to labour. This represents 42 FTEs including three Contract Managers, two Civil Contracts & Inspection Managers, one Project Manager, 21 Civil Inspectors, four Pole Maintenance Coordinators, four Line Field Representatives, one administrative assistant. Six FTEs that represent overtime which is driven by peak demand. The FTEs are supplemented by 14 external inspectors during peak times.

5C.4.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5C-5 Program and Contract Management KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.3 L1	13.8	11.6	14.1	11.9	14.3	12.8	14.0	14.2
2	FTEs	16.0 L15	213	205	217	206	217	221	228	228

Operating Costs are increasing by approximately $1.2 million from fiscal 2019 forecast to fiscal 2020 plan due to:

- A re-organization in September 2018 that transferred four FTEs from the Stations Field Operations KBU to Program and Contract Management KBU ($0.6 million);
- Standard Labour Rate increases ($0.5 million); and
- NERC CIPv5 sustainment resources, as discussed further in section 5C.10.3 ($0.1 million).

Operating Costs are increasing by approximately $0.2 million from fiscal 2020 plan to fiscal 2021 plan due to Standard Labour Rate increases.

FTEs are planned to increase by seven from fiscal 2019 forecast to fiscal 2020 plan due to the transfer of four FTEs from Stations Field Operations KBU, two Workforce Optimization Program conversions and the addition of one FTE for NERC CIPv5 sustainment.

5C.5 Line Field Operations KBU

5C.5.1 Responsibilities

The Line Field Operations KBU is responsible for executing the day to day operational activities on BC Hydro's distribution and transmission line system. Key activities performed by this KBU include:

- **New customer connections to the BC Hydro system:** Once customers have approved designs to connect to the BC Hydro system, Line Field Operations KBU crews complete the connections in accordance with BC Hydro customer service targets for connection times;
- **Preventative, corrective, and condition based maintenance activities as directed by the Integrated Planning Business Group:** Planned maintenance activities are based on system need determined by the Integrated Planning

Business Group, and are executed by Distribution, Transmission and Trouble Line Field Operations crews;

- **End-of-life equipment replacements and small system improvement projects:** This work is organized as projects, managed by the Program and Contract Management KBU, and generally consists of smaller-scale projects not requiring the full level of project oversight associated with larger capital projects. Distribution and Transmission Line Field Operations crews deliver this work;
- **Restoration work due to emergent trouble response including major storm events:** When the Power System incurs damage due to weather, natural disasters such as wildfires, or other situations such as motor vehicle accidents, Distribution, Transmission and Trouble Line Field Operations crews all play a role in repairing the system and restoring customers. The work is performed with the assistance of the Hydro Restoration Center, which triages the damage and dispatches emergent work to crews. For larger events such as major storms, Power Line Technicians respond in the field, supported by field managers and administrators working in Storm Rooms and Regional Emergency Operations Centers, assisted by the Hydro Restoration Center;
- **Maintenance, installation, and replacement of customer meters:** New customer connections and changes to both residential and commercial customers' service requirements require meters to be installed, changed or upgraded. This work is performed by the Provincial Metering Operations department of this KBU. BC Hydro also must comply with legal requirements established by Measurement Canada, and this testing and calibrating work is completed at the provincial meter shop; and
- **Switching operations, as directed by the T&D Systems Operations KBU:** Since the T&D Systems Operations KBU has a view of the entire transmission and distribution system, it has insight into opportunities to open and close field

devices allowing the desired flow of power either to enable repairs to take place or to minimize customer outages. Distribution, Transmission and Trouble Line Field Operation crews perform these switching duties as directed by T&D Systems Operations KBU.

This KBU was created subsequent to the filing of the Previous Application. It includes a number of departments from the former Field and Grid Operations KBU.

This KBU is comprised of the following four departments:

- Distribution Line Field Operations Department;
- Transmission Line Field Operations Department;
- Trouble Line Field Operations and Operations Support Department; and
- Provincial Metering Operations Department.

5C.5.1.1. Distribution Line Field Operations Department

This department is responsible for maintenance and construction activities on approximately 56,000 km of distribution overhead and underground lines and cable, and executing switching operations as directed by T&D System Operations. The department is also responsible for initial storm and major event response and restoration in BC Hydro's service area, and response to routine trouble outside of the Greater Vancouver area and Victoria, where first response is generally provided by the Trouble Line Field Operations department. Distribution Line Field Operations also implements customer connections, executes small system improvement projects, and performs routine maintenance. The department is primarily comprised of Power Line Technicians.

5C.5.1.2. Transmission Line Field Operations Department

This department is responsible for maintenance and construction activities on approximately 18,000 km of overhead, underground, and submarine transmission lines, underground distribution lines, and executing switching operations as directed by T&D System Operations KBU. Maintenance work carried out by this department includes visual inspections, testing, repair, and replacement of transmission and distribution underground equipment. The Transmission Line Field Operations department also provides emergency response and restoration for the BC Hydro transmission system, including routine trouble and major storm damage, and supports distribution line restoration in storms once transmission lines have been restored. The department is primarily comprised of Power Line Technicians and Cable Splicers.

5C.5.1.3. Trouble Line Field Operations and Operations Support Department

This department consists of the Trouble Line Field Operations Team and the Operations Support team.

The Trouble Line Field Operations Team is responsible for day-to-day routine outage restoration on the distribution system within the Greater Vancouver area and Victoria. The department also supports Distribution Line Field Operations and Transmission Line Field Operations when those departments are responding to storm events. This team is primarily comprised of Power Line Technicians.

The Operations Support team provides administrative and operational support to the front-line managers and crew. It consists of the Hydro Restoration Center and the Operations Support Processing Center teams:

- The Hydro Restoration Center team provides support for Power System restoration activities. The team dispatches Distribution or Trouble field crews to respond to customer outages based on information from customer calls, smart meters and protection equipment such as re-closers and circuit breakers. The team also works closely with First Responders to provide them with BC Hydro support when required in the case of community emergencies that involve BC Hydro equipment; and

- The Operations Support Processing Center team provides planned outage notifications, centralized administration of timesheets and expense processing for employees. The team also processes work order completions.

5C.5.1.4. Provincial Metering Operations Department

This department maintains the Meter Shop facility and conducts testing, installation and replacement of meters. This department is primarily comprised of Meter Technicians.

5C.5.2 Overview of Operating Costs and FTEs

Table 5C-6 Line Field Operations KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Director, Line Field Operations	0.4	0.0	0.2	0.0	0.0	0.0	0.0	**0.6**	2
2	Distribution Line Field Operations	16.7	0.0	2.6	2.4	0.1	0.0	0.0	**21.7**	592
3	Transmission Line Field Operations	3.9	0.0	0.3	0.6	0.6	0.0	0.0	**5.4**	166
4	Trouble Line Field Ops and Ops Support	24.5	0.0	12.2	1.2	0.1	0.0	0.0	**38.0**	123
5	Provincial Metering Operations	1.2	0.0	0.1	0.1	0.1	0.0	0.0	**1.6**	48
6	Disconnect Reconnect Work	0.4	0.0	0.5	0.0	0.0	0.0	0.0	**0.9**	-
7	**Total (Sch 5.3 L2, Sch 16.0 L16)**	**47.0**	**0.0**	**15.9**	**4.3**	**1.0**	**0.0**	**0.0**	**68.2**	**931**

5C.5.2.1. Director, Line Field Operations Department

This department holds the budget for the Director of the Line Field Operations KBU. It primarily consists of labour costs for the Director and an administrative assistant. Non-labour costs include funding for monthly Front Line Employee Councils and travel for regional visits.

5C.5.2.2. Distribution Line Field Operations Department

This department is organized into three regional teams: Lower Mainland, Interior and Vancouver Island. Across the three regions, there are 48 managers, three administrative assistants, 37 Field Service Administrators, and 365 trades FTEs, located in 68 regional offices. An additional 139 FTEs that represent overtime which is driven by peak demand are budgeted each year. This is primarily for Trouble response outside of normal operating hours but also to accommodate customer schedules and to minimize the costs incurred to demobilize active crews and mobilize new crews in their place.

The level of resourcing in this department is driven by BC Hydro's customer service objective to respond to Trouble incidents within one hour in urban locations and two hours in rural locations. It also reflects regional work volumes for maintenance, capital, and customer driven work.

Approximately 90 per cent of the labour costs for the trades positions in this department are charged out to distribution capital projects and maintenance programs. Overtime is charged out 100 per cent to these projects and programs. The time not charged to projects and programs is allocated to safety training, technical training and to team, management and safety meetings as well as shop time.

Non-labour costs in this department are for the purchase of personal protection equipment, small tools and crew supplies, required cyclical tool testing and travel to complete training requirements.

5C.5.2.3. Transmission Line Field Operations Department

This department is organized into two regional teams: Lower Mainland/Vancouver Island and South Interior/North Interior. Across these two teams, there are 15 managers, four Field Service Administrators, 10 Transmission Technologists, and 96 trades FTEs. An additional 41 FTEs in overtime is budgeted for when seasonal demand exceeds supply.

The number of FTEs in this department is driven by regional work volumes on transmission maintenance programs and transmission capital projects. On average, these crews deliver about 88,000 hours work on recurring Transmission and Distribution Capital Programs and Projects and spend another 52,000 hours on Corrective and Preventative Transmission Maintenance activities.

Approximately 90 per cent of the labour costs for positions in this department are charged out to transmission maintenance programs and transmission capital projects. Overtime is charged out 100 per cent to projects and programs. The time not charged to projects and programs is allocated to safety training, technical training and to other management and administrative activities such as safety and team meetings.

Non-labour costs in this department are for the purchase of personal protection equipment, small tools and crew supplies, required cyclical tool testing and travel to complete training requirements.

5C.5.2.4. Trouble Line Field Operations and Operations Support Department

This department consists of the Trouble Line Field Operations team and the Operations Support team. It also holds the budget for Distribution Restoration maintenance. Maintenance is discussed in Chapter 5, section 5.8. The department is led by a manager with support from an administrative assistant and two project managers.

The Trouble Line Field Operations team consists of six managers, two Field Service Administrators, and 44 trades FTEs. An additional 17 FTEs in overtime is budgeted each year, primarily to respond to overall restoration work demand.

Approximately 90 per cent of the labour costs for trades positions in this department are charged out to Distribution Restoration maintenance programs, which are discussed further in Chapter 5, section 5.8. Overtime is charged out 100 per cent to these programs. The time not charged to projects and programs is allocated to safety training, technical training and to activities such as safety and team meetings and shop work.

Non-labour costs in this department are for the purchase of personal protection equipment, protective clothing and small tools as well as required cyclical tool testing and travel for training requirements.

The Operations Support Team includes the Operations Support Processing Center team and the Hydro Restoration Center team.

The Hydro Restoration Center team operates four in-take stations to respond to power outage calls. Two in-take stations are operated 24/7 and two in-take stations are operated from 7:00 a.m. to 11:00 p.m., when call volumes are higher. The team consists of 22 FTEs including a manager, an analyst and 20 dispatchers. Included in the budget is one FTE that represent overtime which is driven by peak demand. In fiscal 2018, this team answered approximately 85,000 calls.

The Operations Support Processing Center team consists of 27 FTEs and is primarily made up of Field Service Administrators. In fiscal 2018, this team processed approximately 135,000 timesheets, 93,000 employee expense claims and issued 6,155 planned outage notifications.

Non-labour expenses for this department include training, team activities, and office supplies.

5C.5.2.5. Provincial Metering Operations Department

This department consists of an Electronic Meter Shop and two Field Metering teams. One team provides service to Lower Mainland North and Vancouver Island and the other team provides service to Lower Mainland South and the Interior.

Across the three teams, there are four managers, two Field Service Administrators, one Network and Equipment Co-ordinator, and 33 trades FTEs. In addition, there are eight FTEs that represent overtime which is driven by peak demand. This is associated with the accommodation of customer installation schedules, and minimizing mobilization and demobilization costs.

Approximately 90 per cent of the labour costs for positions in this department are charged out to projects and programs. Overtime is charged out 100 per cent to projects and programs. The time not charged to projects and programs is allocated to safety training, technical training and other management and administrative activities such as safety and team meetings.

Non-labour costs in this department are for the purchase of personal protection equipment, small tools and crew supplies, required cyclical tool testing and travel to complete training requirements.

In fiscal 2018, this department completed approximately 4300 customer connections and 5100 meter exchanges. It also received or issued approximately 64,000 meters, performed approximately 21,000 firmware upgrades on those meters and assembled or upgraded approximately 3250 meters.

5C.5.2.6. Disconnect Reconnect Work Department

This department does not contain any FTEs. When internal or external field crews manually disconnect or reconnect meters, they charge their time to this department. BC Hydro may perform a manual disconnection or reconnection:

- To allow customers to safely perform non-electrical maintenance;
- To enable customers to perform maintenance or repairs on their own;
- When a meter is not within the Smart Meter service area; or
- When service is no longer required at an address.

5C.5.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5C-7 Line Field Operations KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.3 L2	67.7	69.8	68.2	71.6	68.7	68.2	82.3	83.1
2	FTEs	16.0 L16	844	838	844	856	844	931	938	938

Operating costs are increasing by approximately $14.1 million from fiscal 2019 forecast to fiscal 2020 plan due to an increase of $11.1 million to the five-year average that drives the storm response budget (discussed further in Chapter 5, section 5.5.2), Standard Labour Rate increases ($2.0 million), and the transfer of funding for Apprentices from the Business Unit Support KBU in the Operations Business Group ($1.0 million).

Operating costs are increasing by approximately $0.8 million from fiscal 2020 plan to fiscal 2021 plan due to Standard Labour Rate increases.

FTEs are increasing by seven from fiscal 2019 forecast to fiscal 2020 plan due to the Workforce Optimization Program, described in Chapter 5, section 5.6.1.

The increase in FTEs from fiscal 2019 RRA to fiscal 2019 forecast was primarily driven by the Workforce Optimization program, described in Chapter 5, section 5.6.1.

5C.6 Stations Field Operations KBU

5C.6.1 Responsibilities

The Stations Field Operations KBU is a technical frontline management and trades team responsible for executing maintenance, equipment operations, and capital projects support at over 300 generation, transmission, and distribution stations assets. This KBU was created subsequent to the filing of the Previous Application and includes responsibilities that were previously part of the former Generation Operations and Field & Grid Operations KBUs.

The Stations Field Operations KBU is organized into four regions:

- Northern Interior;
- Southern Interior;
- Lower Mainland/Bridge River; and
- Vancouver Island/Thermal/Non-Integrated Areas.

Each region is managed by a Regional Manager and comprised of trades employees with Senior Field Managers, Field Managers, Project Managers, a Construction Contracts Specialist, and Planning and Scheduling teams located throughout the different headquarters for trades and work management. The work performed by this KBU includes:

- Work planning and scheduling for executing maintenance and manual equipment operations;
- Equipment switching, isolation, and manual equipment operations;
- Equipment inspection, cleaning, testing, measurements, repairs, calibration, fluid and filter changes, and troubleshooting;
- Trades staff support for capital projects implementation;
- Spillway field operations and water conveyance;
- Safety inspections; and
- Emergency and off-hours equipment trouble response.

5C.6.2 Overview of Operating Costs and FTEs

Table 5C-8 Stations Field Operations KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Station Field Operations Director	0.5	0.0	1.7	0.0	0.0	0.0	0.0	**2.3**	3
2	Field Grid Ops Third Party Work	0.1	0.0	0.0	0.0	0.0	0.0	0.0	**0.1**	-
3	Apprentices and Trades Trainees	1.0	0.0	0.1	0.1	0.0	0.0	0.0	**1.2**	-
4	Stations Operations	26.6	0.0	10.8	1.5	0.9	0.0	0.0	**39.9**	807
5	Generation Maintenance	2.4	0.0	0.3	0.0	0.1	0.0	0.0	**2.8**	48
6	**Total (Sch 5.3 L3, Sch 16.0 L17)**	**30.5**	**0.0**	**13.0**	**1.7**	**1.0**	**0.0**	**0.0**	**46.2**	**858**

In September 2018, the Stations Field Operations KBU underwent a re-organization to align with the Plan-Build-Operate-Support business model. The goals of this re-organization were to consolidate trades staff within the same geographic region performing similar work on similar equipment under one KBU and one management structure and to reduce duplicate procedures and processes.

As part of the re-organization, a number of FTEs included in Table 5C-8 above were transferred from the Stations Field Operations KBU to other KBUs, reducing the total FTE count for the Stations Field Operations KBU. This reduction is reflected in Table 5C-9 below for fiscal 2020 and fiscal 2021.

- 22 FTEs were transferred from the Stations Operations department to the Engineering KBU;
- Four FTEs were transferred from the Stations Operations department to the Stations Asset Planning KBU;
- Four FTEs were transferred from the Stations Operations department to the Program and Contract Management KBU;
- Five FTEs were transferred from the Generation Maintenance department to the Stations Asset Planning KBU;
- Four FTEs were transferred from the Generation Maintenance department to the Energy Planning and Analytics KBU; and
- 36 FTEs were transferred from the Generation Maintenance department to the Engineering KBU.

Additional details on these transfers can be found in the sections for each of the receiving KBUs.

As part of the re-organization, the generating stations maintenance budget of approximately $52.7 million previously held by Stations Field Operations was transferred to the Stations Asset Planning KBU in the Integrated Planning Business Group which combined the overall stations maintenance budget into a single portfolio in Integrated Planning. Accordingly, the Stations Operations maintenance budget is described within the Station Asset Planning KBU in Chapter 5A, section 5A.6.

The sections below describe the Operating Costs and FTEs for the Stations Field Operations departments, after these transfers were complete.

5C.6.2.1. Stations Field Operations Director Department

This department includes three FTEs: the Director of the KBU, a Transition Manager responsible for aligning business processes across the KBU, and an administrative assistant.

The Services – Other budget for this department includes $1.5 million in reserve funding to perform unanticipated maintenance and repairs on Stations assets and facilities which cannot be absorbed within the fiscal year budget by reprioritizing previously planned work. This budget also includes funding for Public Safety Management Program reviews, consistent with regulatory compliance requirements at Stations facilities.

5C.6.2.2. Field Grid Operations Third Party Work Department

This department does not have any FTEs. Stations Operations staff occasionally complete work requests for industry partners, including apparatus testing and equipment fault investigation and repairs. The labour required to complete these requests is charged to this department and offset through revenue collected through invoices to those industry partners.

5C.6.2.3. Apprentices and Trades Trainees Department

This department does not have any FTEs. The labour budget in this department is for apprentices and trade trainees in the Learning and Development KBU who are working on Stations assets and incur training or meeting time that cannot be charged to work programs or projects. The non-labour budget is for small tools and consumable supplies.

5C.6.2.4. Stations Operations Department

Stations Operations is the workforce required to safely and effectively maintain and operate the Stations assets. This department is organized into four regions as described above:

- Northern Interior;
- Southern Interior;
- Lower Mainland/Bridge River; and
- Vancouver Island/Thermal/Non-Integrated Areas.

The total FTEs for the Stations Operations department, after the September 2018 re-organization, includes 75 manager and professional roles, 550 trades roles, and 53 technical and administrative roles as well as 114 FTEs for overtime.

The number of FTEs in Stations Operations is driven by the work volumes required to complete maintenance, equipment operations, off-hours equipment trouble response, and capital projects support for the stations assets in each region. On average, this department completes approximately 548,000 hours of maintenance, 235,000 hours of capital projects support and 415,000 hours of operations work each year. The labour budget held within this department is for operations work. The labour budgets for maintenance are held within the Integrated Planning Business Group. The labour budgets for capital projects support are held within the Capital Infrastructure Project Delivery Business Group.

The total FTEs and associated overtime allocations for Stations Operations have remained essentially constant over the past four fiscal years despite increasing work demands due to aging assets, additional equipment added to the system, capital support needs, and increased safety, environmental, and regulatory requirements.

The 114 FTEs of overtime included in this department is used primarily by trades employees to meet seasonal and overall work demand peaks for manual equipment operations, off-hours equipment trouble response, maintenance, and capital projects support. These demand peaks occur as a result of seasonal constraints on work volumes due to equipment availability requirements for system loads, environmental and inflow conditions, and water license requirements.

The non-labour budget for this department includes services, materials, and buildings and equipment. The services portion includes the John Hart Generating Station public-private partnership contract with InPower, the General Electric emergency support engine lease and the distributed control system support at the Fort Nelson Gas Generating Station, the Mica Emergency Response Team, janitorial and waste removal, tools and equipment calibration and testing, training, and travel expenses.

The materials portion includes shop supplies, fire retardant clothing and personal protective equipment, as well as office supplies.

The building and equipment portion includes the Campbell River Ironwood office lease, the Burrard Generating Station foreshore lease, and internet and communications charges for the Mica, Hudson Hope, and Bridge River employee accommodations.

With the exception of cost increases for the John Hart partnership contract, the Stations Operations department budget has remained essentially constant for the past four fiscal years despite increasing work demands due to aging assets, additional equipment added to the system, capital support needs, and increased safety, environmental, and regulatory requirements.

5C.6.2.5. Generation Maintenance Department

As discussed above, the September 2018 re-organization transferred the 48 FTEs within the Generation Maintenance department to the Engineering, Stations Asset Planning and Energy Planning and Analytics KBUs. The labour portion of this budget is for non-billable time including safety and technical training, and the non-labour portion is for travel and expenses.

The positions and associated labour and non-labour budgets that were transferred are further described within the respective KBU sections noted above.

5C.6.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5C-9 Stations Field Operations KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.3 L3	41.0	41.5	41.1	39.4	46.9	46.2	52.9	53.5
2	FTEs	16.0 L17	856	829	856	818	856	858	777	777

Operating costs are increasing by approximately $6.7 million from fiscal 2019 forecast to fiscal 2020 plan. This includes a $2.0 million increase for the first full year of operation of the John Hart Generating Station public-private partnership contract with InPower and $1.2 million for Standard Labour Rate increases. Approximately $3.5 million of the increase is a net transfer from the September 2018 re-organization, which is offset by equivalent reductions in other KBUs and has a net zero impact on BC Hydro’s overall operating cost budget.

Operating costs are increasing by approximately $0.6 million from fiscal 2020 plan to fiscal 2021 plan due to Standard Labour Rate increases.

FTEs are decreasing by 81 from fiscal 2019 forecast to fiscal 2020 plan due to the September 2018 re-organization as well as the following changes that are approximately cost neutral:

- The reduction of three John Hart shift electrician roles that are no longer required with the new plant now in operation;
- The elimination of the Lower Mainland Generation Capital Storekeeper role as part of the Ruskin Re-development capital project completion;

- The reduction of three other FTEs representing a small plants administrator role, an electrician apprentice role, and trades overtime;
- The addition of two Communication, Protection and Control trades at the Mica Generating Station to assist with capital projects implementation;
- The addition of a John Hart Construction Contracts Specialist to act as BC Hydro's representative to InPower, the company contracted to manage the John Hart Generating Station for the first 15 years; and
- The addition of a Field Manager for Electricians and Communication, Protection and Control trades at the Bridge River Generating Station due to the large amount of capital projects underway at that location.

The increase in FTEs from fiscal 2019 RRA to fiscal 2019 forecast was primarily driven by the Workforce Optimization program, described in Chapter 5, section 5.6.1.

5C.7 Distribution Design and Customer Connections KBU

5C.7.1 Responsibilities

The Distribution Design and Customer Connections KBU is a technical and front line customer group that leads the new customer connections program for distribution voltage customers (25 kV and under) and provides design work, project coordination and work packages for other distribution system improvement and end of life asset replacement programs. It is a high volume business area, producing over 35,000 service orders and 15,000 designs and work order packages annually. The Designers in this KBU are also regularly deployed in emergency response roles as damage assessors and wire guards because of their technical expertise and knowledge of the distribution system.

The above activities are performed by Designers located in 29 district offices throughout the province, as well as Electrical Service Coordinators working in centralized Express Connect centres in Kamloops, Burnaby and Nanaimo.

The customer connection work, driven by customer connection requests, is the highest priority and largest work program for the Distribution Design and Customer Connections KBU. Customer work is the provision of new or upgraded electrical services as requested by current and future residential, commercial or industrial BC Hydro customers. By their nature, all of these requests are “unplanned” throughout the year and range from simple overhead services to very large and complex multi-million dollar projects. The customer work involves liaising with customers and their consultants and contractors, electrical and civil design, estimating and quoting, work package development and project management activities. Chapter 6, section 6.4.15.1 provides additional information on the Customer Capital Program managed by Distribution Design and Customer Connections KBU, including customer contributions in aid.

Planned work programs such as system improvement projects make up the remainder of the work for this KBU. These programs are described further in Chapter 6, sections 6.4.15.1 and 6.4.15.2.

This KBU was part of the Customer Service and Distribution Design KBU in the Previous Application. There have been no material changes to the responsibilities of this KBU since the Previous Application.

Distribution Design and Customer Connections KBU is comprised of the following departments:

- Customer Program Office Department;
- Distribution Design Department;
- Design Programs and Services Department;

- Customer Connections Department; and
- Customer Connect Work Programs Department.

5C.7.1.1. Customer Program Office Department

This department provides program management for the customer capital program and monitors the customer connection processes through metrics and reporting. It also initiates and leads process and technology improvement projects, such as new on-line capabilities, to increase efficiency and improve customer service and experience.

5C.7.1.2. Distribution Design Department

This department plans, designs, and provides project coordination for customer connections to BC Hydro's distribution system and other province-wide distribution system improvement and asset replacement projects and programs that require design, estimating and work packages. The department issues approximately 15,000 work orders to distribution line crews and civil contractors every year.

5C.7.1.3. Design Programs and Services Department

This department provides technical design for large system improvement projects and provides quality assurance of work designed by BC Hydro approved professional engineering firms.

5C.7.1.4. Customer Connections (Express) Department

This department, usually called Express Connections, responds to over 35,000 customer requests each year for simple new service connections, upgrades, and service disconnects. Through a provincial contact centre with staff located in three regions, technically trained Electric Service Coordinators handle calls and applications from customers and issue simple work orders to crews.

5C.7.1.5. Customer Connect Work Programs

The Customer Connect Work Programs department does not contain any FTEs. It contains costs associated with services requested by customers that are not directly related to new or upgraded services. Examples include temporary re-locations and guarding of overhead lines for house moves and active construction sites, customer electrical vault isolations and temporary construction power. Customers are charged for these services and payments are received as revenue.

5C.7.2 Overview of Operating Costs and FTEs

Table 5C-10 Distribution Design Customer Connections KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Mgr Dist'n Design and Custmr Connection	0.5	0.0	0.1	0.0	0.0	0.0	0.0	**0.7**	3
2	Customer Program Office	0.3	0.0	0.2	0.0	0.0	0.0	0.0	**0.5**	2
3	Distribution Design	7.3	0.0	0.9	0.2	0.1	0.0	0.0	**8.6**	293
4	Design Programs and Services	0.4	0.0	0.1	0.0	0.0	0.0	0.0	**0.5**	17
5	Customer Connections	1.5	0.0	0.1	0.0	0.0	0.0	0.0	**1.6**	64
6	CC Work Programs	0.6	0.0	1.4	0.4	0.0	0.0	0.0	**2.5**	-
7	**Total (Sch 5.3 L4, Sch 16.0 L18)**	**10.7**	**0.0**	**2.7**	**0.7**	**0.2**	**0.0**	**0.0**	**14.3**	**379**

The level of economic activity in the province is the single largest driver of the Customer Capital Program and workload for Distribution Design and Customer Connections KBU. Housing starts, multi-year provincial infrastructure investments, and new industries such as cannabis grow operations have contributed to a construction boom over the past three years. This, in turn, has led to an unprecedented volume of distribution customer connection requests, with fiscal 2018 and fiscal 2019 having the highest number of connection requests in BC Hydro's history. The Customer Capital Program capital expenditures have increased from $170 million in fiscal 2016 to a forecast of $234 million for fiscal 2019.

The work involved to complete these customer service requests has become increasingly complex over the past five years due to increased environmental and safety regulations and municipal planning requirements. Evolving customer needs and expectations also require new processes and capabilities. Distribution Design and Customer Connections KBU is currently implementing broader web–based services for electrical service applications and on-line banking for project payments.

The high customer activity levels are expected to remain for another two years through the fiscal 2020 and fiscal 2021 test period, based on what is in the current pipeline and the expected impacts of the electrification programs by the Government of B.C. and municipalities.

Overall, the utilization rate of designer and electrical service coordinator positions is 91 per cent, which means only 9 per cent of employees' time is used for training, initiatives and administrative requirements and the rest is charged to work.

5C.7.2.1. Manager, Distribution Design and Customer Connections Department

The budget for this department primarily consists of labour for the Director of the KBU, an administrative assistant and a program manager.

5C.7.2.2. Customer Program Office Department

This budget for this department primarily consists of labour for a Project Manager and a Business Improvement Manager.

5C.7.2.3. Distribution Design Department

Most of the work performed by this department is charged out to the Customer Capital Program and other Distribution growth and sustaining capital work programs and projects as described in Chapter 6, sections 6.4.15.1 and 6.4.15.2. The majority of the labour budget in this department covers training and administrative time that is not chargeable to these programs. There are 293 FTEs in this department consisting of 213 Designers, 36 Design Assistants and administrators, 15 front-line Design Managers, seven Senior Design Managers and two Division Managers. The remaining 20 FTEs represents overtime which is driven by peak demand.

Every year, the Resource Strategy and Management department models demand for distribution design services against design capacity. The model includes internal Designer headcount and demographics (trainees and experienced Designers), overtime and the availability of external engineering service providers to augment capacity at a regional level. This modelling currently shows there is a good balance between internal Designers and contractors for the forecasted workload. If there was a slowdown in customer work, there is enough contracted work that could be pulled back in-house to keep internal Designers fully utilized.

Although engineering firms can provide design services for system improvement and end of life projects, they are unable to undertake the estimating, quoting and local customer communications work required for customer projects that involve the Electric Tariff and extension policy. Therefore, internal Designers based out of local district offices deliver all the customer connections work, with the exception of a few large projects where external firms provide the technical design and the small Customer Build Program for residential subdivisions where BC Hydro quoting is not required.

To handle the increase in customer requests and maintain reasonable service levels, this department has added 28 designers, some temporary, over the past two fiscal years. These positions also offset the need to contract out more design work at a higher cost. The additions are included in the design demand and capacity modelling described above. The current forecast indicates that current staffing levels will need to be maintained through the test period.

5C.7.2.4. Design Programs and Services Department

Most of the work performed by this department is charged out to Distribution growth and sustaining capital work programs and projects as described in Chapter 6, sections 6.4.15.1 and 6.4.15.2. The majority of the labour budget covers training and administrative time that is not chargeable to these programs. The 17 FTEs in this department consist of 10 Designers, five Distribution Project Coordinators, one Services and Design Assistant, and one front-line Design Manager.

5C.7.2.5. Customer Connections (Express) Department

This department is comprised primarily of Electric Service Coordinators. Most of the work performed by this department is charged out to the Customer Capital Program described in Chapter 6, section 6.4.15.1. The majority of the labour budget covers training and administrative time that is not chargeable to this program.

The scope of express connection services provided by BC Hydro is unique among Canadian and U.S. utilities and provides an efficient model that minimizes design work effort. To handle the unprecedented increase in customer requests and maintain reasonable service levels, this department added seven Electric Service Coordinator positions over fiscal 2017 and fiscal 2018, funded entirely through contractor cost savings and reductions in overtime.

While the volume of service requests has increased and become more complex, response times for express customer connections have substantially improved over the past three years. BC Hydro conducts a monthly customer satisfaction survey which indicates the overall satisfaction level has increased from an average of 70 per cent three years ago to above 85 per cent in 2018. Connection times have decreased from 12 days to eight days over the same period.

5C.7.2.6. Customer Connect Work Programs

The Customer Connect Work Programs department does not contain any FTEs. It contains costs associated with services requested by customers that are not directly related to a new or upgraded service. Customers are charged for these services and payments are received as revenue.

5C.7.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5C-11 Distribution Design Customer Connections KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.3 L4	12.8	10.2	13.1	10.6	13.5	14.3	14.8	15.1
2	FTEs	16.0 L18	338	325	338	347	338	379	379	379

Operating costs are increasing by approximately $0.5 million from fiscal 2019 forecast to fiscal 2020 plan and by approximately $0.3 million from fiscal 2020 plan to fiscal 2021 plan, due to Standard Labour Rate increases. FTEs are planned to remain constant.

The increase in FTEs from fiscal 2019 RRA to fiscal 2019 forecast was primarily driven by the Workforce Optimization program, described in Chapter 5, section 5.6.1.

5C.8 Construction Services KBU

5C.8.1 Responsibilities

The Construction Services KBU provides a range of services supporting the capital replacement, maintenance and capital expansion of transmission, distribution, station, and generation assets. This KBU is comprised of full time regular managers and office staff who manage and support a scalable full-time temporary workforce of approximately 300 trade employees. There have been no material changes to the responsibilities, organization and make-up of the Construction Services KBU since the Previous Application.

The Construction Services KBU is comprised of the following departments:

- Construction Services Lower Mainland / Vancouver Island;
- Construction Services South Interior / North Interior; and

- Project Planning and Coordination.

5C.8.1.1. Regional Departments

The Lower Mainland / Vancouver Island and Southern Interior / Northern Interior departments are organized by geographic boundaries and are responsible for the four regional offices located in the regions they serve:

- Prince George (Northern Interior);
- Vernon (Southern Interior);
- Surrey (Lower Mainland); and
- Nanaimo (Vancouver Island).

Construction Services KBU delivers an integrated bundle of services with on-demand skilled construction trades including power line technicians, electricians, general trades (carpenters, millwrights, and mechanics), winders, and equipment operators who are utilized to help implement the BC Hydro maintenance and capital programs. This internal construction group is used in place of contract resources where the implementation risks are more appropriately managed with the use of internal crews. This KBU also provides specialized services, such as construction expertise in planning stages of utility projects, specialty concrete repairs of generation civil infrastructure and asbestos abatement in energized environments.

In addition to increasing BC Hydro's operational flexibility, the Construction Services KBU performs the following:

- Employing highly trained crews who are familiar with BC Hydro facilities, policies, procedures and systems;
- Deploying resources in response to urgent and emergent work;
- Providing solutions to complex, multi-disciplinary projects, particularly when safety or system reliability challenges exists (i.e., brownfield work), or when the

construction risk is more appropriately managed by internal BC Hydro resources rather than being transferred to external contractors;

- Partnering with local First Nations to create development opportunities, and increase engagement through involvement with project work, consistent with BC Hydro's Indigenous Relations strategy;
- Providing timely access to scarce, skilled trades (e.g., winders and specialized civil); and
- Maintaining a workforce that is scalable, mobile and transferrable and can respond to overall changes in long-term capital demand as well as short-term project based work.

5C.8.1.2. Project Planning and Coordination Department

The Project Planning and Coordination department consists primarily of Construction Technologists. It is responsible for developing and maintaining project management practices and processes. The department also supports the Construction Services KBU field staff in planning and implementing projects.

5C.8.2 Overview of Operating Costs and FTEs

Table 5C-12 Construction Services KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	CS-General Manager	0.4	0.0	0.2	0.0	0.0	0.0	0.0	**0.6**	3
2	Regional Departments	7.6	0.0	1.1	2.1	0.7	0.0	0.0	**11.6**	377
3	Project, Planning and Coordination Departme	0.5	0.0	0.0	0.0	0.0	0.0	0.0	**0.6**	19
4	**Total (Sch 5.3 L5, Sch 16.0 L19)**	**8.6**	**0.0**	**1.4**	**2.2**	**0.7**	**0.0**	**0.0**	**12.8**	**398**

5C.8.2.1. General Manager Department

The majority of the General Manager's department budget is related to labour. This represents three FTEs: the General Manager, an administrative assistant and a Business Operations Manager.

5C.8.2.2. Regional Departments

The regional departments' workforce assists with the delivery of the Transmission, Generation, and Distribution capital and maintenance programs. The overall demand for the workforce is driven by the expansion or contraction of capital and maintenance expenditures in these programs. There are 377 FTEs charged to these programs for work performed, of which approximately 73 FTEs represents overtime which is driven by seasonal or peak demand. Across the four regions combined, there are 24 managers, 15 Field Service Administrators, and 265 trades FTEs.

The labour budget for trade positions in these departments are charged out 90 per cent to projects and programs. Overtime is charged out 100 per cent to projects and programs. The time not charged to projects and programs is allocated to safety training, technical training and other management and administrative activities such as team and safety meetings.

The non-labour expenses budgeted in these departments are for the purchase of personal protection equipment, small tools and crew supplies, required cyclical tool testing and travel for training requirements.

5C.8.2.3. Project Planning and Coordination Department

Almost all of the Project Planning and Coordination department's budget is related to labour. This represents 19 FTEs including two managers, 16 temporary project planning coordinators and one temporary records administrator. Most of the roles in this department are temporary to allow the workforce to be scaled according to project volumes. FTEs in this department charge 90 per cent of their time to projects and programs. The labour costs associated with this time are not included in the department's operating budget. The time not charged to projects and programs is allocated to Safety Training, Technical and Professional Training, and management and administrative activities such as team and safety meetings.

5C.8.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5C-13 Construction Services KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.3 L5	13.5	11.4	13.7	12.4	13.9	12.8	13.2	13.3
2	FTEs	16.0 L19	404	411	404	409	404	398	397	397

Operating costs are increasing by approximately $0.4 million from fiscal 2019 forecast to fiscal 2020 plan and by approximately $0.1 million from fiscal 2020 plan to fiscal 2021 plan, due to Standard Labour Rate increases. FTEs are planned to remain constant.

5C.9 Generation System Operations KBU

5C.9.1 Responsibilities

The Generation System Operations KBU is responsible for planning the operation of BC Hydro’s reservoirs and generation facilities and for integrating other resources into those operations to meet BC Hydro’s load obligations.

The Generation System Operations KBU plans short to mid-term (hourly up to three years) dispatch of both the Heritage Assets and the dispatchable Non-Heritage generating resources. This involves the consideration of inputs such as loads, inflows, outages, and market conditions. This KBU also determines the surplus system capability available to BC Hydro’s electricity trading subsidiary, Powerex. In addition, the Generation System Operations KBU manages BC Hydro’s water licenses as well as the Columbia River Treaty, Canal Plant Agreement, Keenleyside Entitlement Agreement and the Waneta Co-Possessors and Operating Agreement with Teck.

This KBU was called Generation Resource Management in the Previous Application. The name was changed to better reflect its role and to distinguish its functions from the Stations Field Operations KBU. There have been no material changes to the responsibilities of this KBU since the Previous Application.

The Generation System Operations KBU is composed of the following five departments:

- Planning, Scheduling and Operations Department;
- Operations Planning Department;
- Planning and Licensing Department;
- Hydrology Department; and
- Generation System Operations Department.

5C.9.1.1. Planning, Scheduling and Operations Department

This department directs the real-time operation of the BC Hydro generation system and water release facilities. This includes scheduling hourly generation of the BC Hydro system and contracted IPPs and identifying Powerex trade limits. The dispatch of these decisions is conducted by T&D System Operations KBU.

5C.9.1.2. Operations Planning Department

This department is responsible for planning water releases and generation dispatch over the medium to long-term (daily/weekly to multi-year time horizon). In addition, this department implements coordination agreements with utility partners, directs the purchase and sale of electricity from Powerex for domestic needs, sets system reservoir price signals, and forecasts the cost of operations for financial reporting purposes.

5C.9.1.3. Planning and Licensing Department

This department is responsible for managing BC Hydro’s water licenses, coordination agreements including the Columbia River Treaty and Canal Plant

Agreement, as well as conducting system analysis and modelling to determine operational and financial benefits and impacts.

5C.9.1.4. Hydrology Department

This department provides weather, inflow and wind forecasts for operational purposes throughout BC Hydro. It also manages a hydro-meteorological data collection network and maintains records of generation facility operations.

5C.9.1.5. Generation Systems Operations Department

This department provides resources, tools, and support to the Generation System Operations KBU. The department's primary areas of responsibility include management of the KBU, application support, and administrative services.

5C.9.2 Overview of Operating Costs and FTEs

Table 5C-14 Generation System Operations KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Planning, Scheduling and Operations	2.3	0.0	0.2	0.0	0.0	0.0	0.0	**2.6**	14
2	Operations Planning	2.8	0.0	0.4	0.0	0.0	0.0	0.0	**3.2**	16
3	Planning and Licensing	1.7	0.0	0.4	0.0	0.0	0.0	0.0	**2.1**	10
4	Hydrology	1.5	0.0	3.0	0.0	0.2	0.0	0.0	**4.7**	13
5	Generation Systems Operations	1.5	0.0	0.1	0.0	0.4	0.0	0.0	**2.0**	11
6	**Total (Sch 5.3 L6, Sch 16.0 L20)**	**9.9**	**0.0**	**4.1**	**0.0**	**0.6**	**0.0**	**0.0**	**14.6**	**64**

From fiscal 2016 to fiscal 2019, total operating costs for this KBU increased by $0.9 million from $13.7 million to $14.6 million. This increase was primarily driven by:

- Increased licensing and maintenance costs required to support specialized applications and models;
- Increased expenditures related to the Water Use Plan Order Reviews; and
- Increased hydrometric monitoring costs.

These cost increases were partially offset by a budget reduction of $0.2 million in fiscal 2019.

From fiscal 2016 to fiscal 2019, total FTEs for this KBU remained constant at 64.

5C.9.2.1. Planning, Scheduling and Operations Department

This department's budget mainly consists of labour costs for 14 FTEs, which includes one manager, a specialist engineer responsible for maintaining all information technology functions and 12 shift Engineers. The shift Engineers rotate through three roles which plan for the next seven days of operation, direct the real-time (24/7) operation of BC Hydro generation and water management, and support the 24/7 operation including after-the-fact analysis of operational decisions related to generation and water management.

This department also has a non-labour budget of $0.2 million for dedicated specialized desktop and local area network support due to the criticality of the technology used by the department.

5C.9.2.2. Operations Planning Department

This department's budget mainly consists of labour costs for 16 FTEs, which includes one manager and 15 FTEs organized into three sub functions: Operations Planning Engineers, Resource Coordinators, and System Optimization Engineers. Engineers in this department plan generation, plant generating capacity, water conveyance and inter-annual storage management, over a daily to multi-year time frame, in coordination with transmission and other system constraints.

This department also has a non-labour budget of $0.4 million for engineering services related to the monitoring and operations of BC Hydro's generating facilities along the Peace River.

5C.9.2.3. Planning and Licensing Department

The Planning and Licensing department's budget consists mainly of labour costs from 10 FTEs, which includes a manager and nine FTEs who work on Water License renewals, Water Use Plan Order Reviews, coordination agreements including the Columbia River Treaty and Canal Plant Agreement, and mid-term and long-term (multi-year) modelling.

This department also includes a non-labour budget of $0.4 million to mainly support resourcing requirements for Water Use Plan Order Reviews.

5C.9.2.4. Hydrology Department

The Hydrology department consists of 13 FTEs, including one manager and 12 FTEs organized into weather and climate services (daily tailored forecast products); operational runoff forecasting (daily and seasonal); hydrometric monitoring station management, and generation data analysis.

The Hydrology department also manages over $3.0 million in service contracts including:

- A cost sharing program with Environment Canada on the operations and maintenance of Canada's Water Survey Stations;
- Hydraulic consultants who operate and maintain BC Hydro's network of 76 Water Stations in Northern and Southern B.C.;
- An agreement with the University of British Columbia to provide numerical weather and wind forecasts; and
- Funding to support the Pacific Climate Impacts Consortium quantitative studies on the impacts of climate change in the Pacific region.

5C.9.2.5. Generation System Operations Department

This department's budget mainly consists of labour costs associated with 11 FTEs including the Director of Generation System Operations, a manager of business operations, a manager of business systems, administrative staff that support the KBU, and application leads who oversee the KBUs information technology applications and tools.

5C.9.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5C-15 Generation System Operations KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.3 L6	14.5	16.0	14.7	14.2	14.8	14.6	15.0	15.2
2	FTEs	16.0 L20	64	65	64	68	64	64	63	63

Operating costs are increasing by approximately $0.4 million from fiscal 2019 forecast to fiscal 2020 plan and by approximately $0.2 million from fiscal 2020 plan to fiscal 2021 plan, due to Standard Labour Rate increases. FTEs are planned to remain constant.

5C.10 T&D System Operations KBU

5C.10.1 Responsibilities

The T&D System Operations KBU is responsible for managing the real time operation of the BC Hydro generation, transmission, distribution and telecommunication systems as well as day-ahead planning of the electricity grid. This KBU relies on input from other BC Hydro departments responsible for scheduling generation, maintenance, and the interconnection of new facilities. It also coordinates with other registered entities in B.C. to ensure the reliable operation of non-BC Hydro facilities such as IPPs and B.C. entities with generation and/or transmission assets.

In addition, this KBU is responsible for managing unplanned outages, implementing BC Hydro's safety policies and procedures for transmission and distribution and supporting and implementing emergency management preparedness plans. This KBU facilitates fair and open access to the transmission grid for all customers through administration of the Open Access Transmission Tariff and the operation of the wholesale transmission market.

This KBU was called Real Time Operations in the Previous Application. The name was changed to better reflect its role and distinguish this KBU from the Line Field Operations KBU and the Generation System Operations KBU. Since the Previous Application, there have been two material changes to the responsibilities of this KBU:

- The Grid Telecom Operations department has transferred from the former Smart Technology Operations and Restoration KBU to the T&D System Operations KBU; and
- The Provincial Reliability Coordination Operations department has been added into the T&D System Operations KBU. This reflects the BCUC's anticipated appointment of BC Hydro as the Reliability Coordinator for B.C. This role was previously contracted out to Peak Reliability, which has notified BC Hydro and other entities that it will no longer provide this service.

The T&D System Operations KBU is comprised of the following seven departments:

- Operations Support Department;
- Real Time Operations Department;
- Operations Planning Department;
- Market Policy and Operations Department;
- Business Services and Administration Department;
- Grid Telecom Operations Department; and
- Provincial Reliability Coordination Operations Department.

5C.10.1.1. Operations Support Department

The Operations Support department supports the real time computer systems and applications used for electric system monitoring and control by Real Time Operations department. This involves on-site support to the system control centres during business hours as well as on-call support at all other times. The department is also responsible for compliance with the Critical Infrastructure Protection Standards applicable to T&D System Operations KBU, which are among the mandatory reliability standards adopted by the BCUC.

5C.10.1.2. Real Time Operations Department

The Real Time Operations department controls and monitors in real time more than 79,000 kilometers of transmission and distribution circuits, over 30 generating stations, and over 300 substations from BC Hydro's Fraser Valley Control Centre and the Southern Interior Control Centre. The system control centres dispatch generation, restore service when outages occur on the Power System and monitor and control equipment during maintenance and operations. The function is performed 24/7.

This department also performs the outage scheduling function, so that planned outages of generation, transmission, and distribution facilities are safely and efficiently coordinated to enable maintenance of existing facilities and commissioning of new facilities.

5C.10.1.3. Operations Planning Department

The Operations Planning department consists primarily of Power System engineers. The department studies and plans the operation of the electrical grid and coordinates operations with other utilities connected to BC Hydro. This involves examining planned outages of generation and transmission facilities as well as the addition of new facilities to determine their impact on the grid. The department undertakes seasonal studies to develop contingency plans so that operating staff are prepared to manage events on the grid each day as they arise. The department is also responsible for compliance with requirements of the Transmission Operations Standards, which are among the mandatory reliability standards adopted by the BCUC.

5C.10.1.4. Market Policy and Operations Department

The Market Policy and Operations department is the point of contact for BC Hydro's Open Access Transmission Tariff customers. The department is responsible for wholesale transmission market policies, contracts, the Open Access Transmission Tariff, and the administration of wholesale transmission services. This includes transmission pre-scheduling, settlements and billing, energy accounting, revenue reporting and forecasting, data reporting, as well as business systems sustainment and enhancements.

5C.10.1.5. Business Services and Administration Department

This department provides administrative support to employees at the Fraser Valley Control Centre and the Southern Interior Control Centre.

5C.10.1.6. Grid Telecom Operations Department

The Grid Telecom Operations department is responsible for the telecommunications network that supports critical infrastructure throughout the BC Hydro electrical system. The network provides electric system protection, stability, visibility and control to the system control centres. Employees in this department provide 24/7 onsite support to the system control centres and field workers. These employees are augmented by a support team, which tests existing and new hardware and software in a controlled laboratory environment. The testing conducted by this team identifies issues early and limits the amount of changes that are required after equipment has already been deployed onto the system.

5C.10.1.7. Provincial Reliability Coordination Operations Department

This is a new department established in October 2018. The costs are being funded internally for the remainder of fiscal 2019 from other KBUs across the Operations Business Group. Starting in fiscal 2020, the costs will be funded from the Inter-utility Operations department.

In July 2018, Peak Reliability, the existing Reliability Coordinator for B.C., announced that it would no longer provide Reliability Coordinator services after December 31, 2019. BC Hydro submitted its application for registration as the Reliability Coordinator for B.C. to the Western Electricity Coordinating Council (**WECC**) on September 4, 2018 and followed up with additional information filed with the BCUC on October 29, 2018.

The Provincial Reliability Coordination Operations department will be responsible for assessing transmission reliability, coordinating system operations, and directing actions to preserve the integrity and reliability of the Bulk Electric System for all of British Columbia.

The Reliability Coordinator function will be staffed by employees who have been certified by the North American Electric Reliability Corporation, meet annual training requirements, and have significant experience in operating or planning the Bulk Electric System. Employees in this department will use operational tools and information to analyze the reliability of the Power System on a continuous basis. They will also be responsible for the coordination and oversight to reliably operate the interconnected grid. In the event of disturbances or blackouts, these employees will intervene to ensure that the grid is restored in a coordinated manner.

5C.10.2 Overview of Operating Costs and FTEs

Table 5C-16 T&D System Operations KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Inter-utility Operations	0.0	0.0	8.9	0.0	0.0	0.0	0.0	**8.9**	-
2	T-Control Centres	0.7	0.0	0.0	0.0	0.0	0.0	0.0	**0.7**	-
3	D-Load Dispatch-Engineering Support	1.2	0.0	0.1	0.0	0.0	0.0	0.0	**1.3**	-
4	D-Load Dispatch-FO Support	1.5	0.0	0.1	0.0	0.0	0.0	0.0	**1.6**	-
5	Operations Support	3.3	0.0	1.5	0.0	1.5	0.0	0.0	**6.3**	27
6	Real Time Operations	12.9	0.0	0.3	0.1	0.2	0.0	0.0	**13.4**	96
7	Operations Planning	1.4	0.0	0.0	0.0	0.2	0.0	0.0	**1.6**	10
8	Market Policy and Operation	0.7	0.0	0.0	0.0	0.0	0.0	0.0	**0.7**	6
9	Business Services and Administration	0.2	0.0	0.0	0.0	0.0	0.0	0.0	**0.2**	4
10	Grid Telecom Operations	2.2	0.0	0.7	0.1	0.5	0.0	0.0	**3.4**	35
11	**Total (Sch 5.3 L7, Sch 16.0 L21)**	**24.1**	**0.0**	**11.6**	**0.2**	**2.4**	**0.0**	**0.0**	**38.3**	**178**

From fiscal 2016 to fiscal 2019, total operating costs for this KBU increased by approximately $5 million, from $33.3 million to $38.3 million. The increase was primarily driven by:

- The centralization of WECC and Peak Reliability funding from across BC Hydro into the T&D System Operations KBU (the centralization is net neutral for BC Hydro as a whole);
- Increases in Peak Reliability's fees, denominated in US$;
- A lower Canada to U.S. exchange rate which increased the cost of WECC and Peak Reliability fees;
- The transfer of funding for applications related to the Energy Management System and the Distribution Management System from other KBUs to the Operations Support department; and
- Increased funding for system maintenance in the Grid Telecom Operations department to support and maintain an increased number of technologies.

From fiscal 2016 to fiscal 2019, total FTEs in this KBU increased by 14 from 164 to 178. This increase was primarily driven by the additional resources required in the Grid Telecom Operations department to support and maintain an increased number of technologies and in the Operations Support department to manage an increase in system maintenance requirements related to the transfer of the additional applications, as mentioned above.

5C.10.2.1. Inter-utility Operations Department

This department does not contain any FTEs. It holds the funding for BC Hydro's mandatory annual membership fees for Peak Reliability and WECC. This budget has increased since fiscal 2016 due to the centralization of funding for these fees from across BC Hydro into the T&D System Operations KBU, increases in PEAK Reliability's fees, and lower Canada to U.S. exchange rates.

5C.10.2.2. Transmission Control Centres Department

This department does not contain any FTEs. When Communication Protection and Control Technologists from stations operations perform corrective work that supports real time monitoring and control, they charge to this department. Approximately 8,000 hours of work is charged to this department each year. This work program is managed by the Real Time Operations department.

5C.10.2.3. Distribution-Load Dispatch-Engineering Support Department

This department does not contain any FTEs. When engineers from the Integrated Planning Business Group conduct power quality investigations, they charge to this department. Approximately 24,000 hours of work is charged to this department each year. This program is managed by the Operations Planning department.

5C.10.2.4. Distribution-Load Dispatch-Field Operations Support Department

This department does not contain any FTEs. When the PLTs from the Line Field Operations KBU perform customer switching activities on distribution equipment to restore power, they charge to this department. Approximately 17,000 hours of work is charged to this department each year. The costs for this program are held by the Real Time Operations department.

5C.10.2.5. Operations Support Department

This department manages the real time systems and consists of 27 FTEs that provide extended hours of on-site technical support for the critical hardware and applications to operate the Power Systems at the Fraser Valley Control Centre and the Southern Interior Control Centre. The department also manages approximately $3 million in licenses, and support and maintenance contracts with external vendors.

5C.10.2.6. Real Time Operations Department

This department consists of 96 FTEs which are required to support 24/7 operation of the Fraser Valley Control Centre and the Southern Interior Control Centre. This includes one Director, 12 System Control Managers, three Specialist Engineers, one Engineering Technical Assistant, one Reliability Coordination Manager and 78 Operators. The Operators are assigned to consoles at the Fraser Valley Control Centre and the Southern Interior Control Centre from which they control various portions of the Power System across the province. The Operator staffing model is built around providing 24/7 coverage and meeting mandatory training needs, while recognizing that staffing can be reduced to a minimum during weekends, evenings and holidays when there is less planned work on the Power System.

5C.10.2.7. Operations Planning Department

This department consists of 10 FTEs and three Engineers-in-Training. These employees:

- Assess approximately 6,500 planned transmission system outage requests per year. These requests can take anywhere from 30 minutes to eight hours and involve engagement, analysis, and the preparation of contingency plans;
- Create support plans for approximately 25 major distribution outages per year, to reduce or eliminate customer impacts. These plans take multiple days to complete including consultation and coordination;
- Develop approximately 20 restoration and mitigation plans per year. These plans are developed in real time during major storm and fire events and take approximately one to two days to complete; and
- Draft and update approximately 120 base operating procedure documents per year. These documents include detailed technical requirements for advanced power system controls and drafting can take multiple days to complete.

5C.10.2.8. Market Policy and Operations Department

This department consists of six FTEs including one manager, one Contract Specialist, one Business System Specialist, and three coordinators. This department manages pre-scheduled sale of transmission service and ancillary services. In fiscal 2018, the department billed over 27.7 million MWh of transmission service and generated $16.5 million in revenue from non-BC Hydro customers.

5C.10.2.9. Business Services and Administration Department

This department consists of four FTEs who provide administrative support to the 150 employees based at the Fraser Valley Control Centre and the Southern Interior Control Centre.

5C.10.2.10. Grid Telecom Operations Department

This department consists of 35 FTEs including one manager, one Field Manager, one Project Manager, two Senior Engineers, 10 Telecom Network Controllers, 13 Communication Protection and Control Technologists, two Project Resource Assistants, one Field Service Administrator, and four FTEs that represent overtime which is driven by peak demand. These FTEs operate BC Hydro's telecom infrastructure, maintain a 24/7 network controller desk, and provide engineering support to more than 40 applications and 1,000 devices at over 200 sites.

5C.10.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5C-17 T&D System Operations KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.3 L7	36.2	38.2	36.7	40.4	37.4	38.3	39.8	40.3
2	FTEs	16.0 L21	165	170	165	174	165	178	197	197

Operating costs are increasing by approximately $1.5 million from the fiscal 2019 forecast to the fiscal 2020 plan due to Standard Labour Rate increases of $1.1 million and funding for NERC CIPv5 sustainment resources of $0.4 million (discussed further below). Operating costs are increasing by approximately $0.5 million from the fiscal 2020 plan to the fiscal 2021 plan due to Standard Labour Rate increases.

FTEs are planned to increase by 19 from the fiscal 2019 forecast to the fiscal 2020 plan. This includes 13 FTEs related to the Provincial Reliability Coordination Operations department, five FTEs related to the sustainment of NERC CIPv5 (discussed further below) as well as one FTE addition through the Workforce Optimization Program, which is discussed further in Chapter 5, section 5.6.1.

The increase in FTEs from the fiscal 2019 RRA to the fiscal 2019 forecast was primarily driven by the Workforce Optimization program, described in Chapter 5, section 5.6.1.

Starting in fiscal 2020, the Provincial Reliability Coordination Operations department will require a budget of $2.5 million which will be funded from within the T&D System Operations department through the re-allocation of the budget previously required for payments to Peak Reliability.

The NERC CIPv5 Program is the enterprise wide program to attain compliance with NERC CIPv5 standards by October 1, 2018. This is a regulatory requirement. NERC CIP is a collection of physical and electronic security standards designed to protect the computer/electronic equipment used to control and monitor the Bulk Electric System from cyber-attack and sabotage.

The BCUC has mandated that BC Hydro comply with NERC CIP as part of the BC Mandatory Reliability Standards Program. The program successfully achieved compliance by the regulatory deadline and is in the process of transitioning into operations.

BC Hydro has re-purposed 18 existing roles to support compliance with NERC CIPv5. The funding for these roles has been provided from within existing operating budgets.

5C.11 Business Unit Support KBU

5C.11.1 Responsibilities

The Operations Business Unit Support KBU holds the budget for the Executive Vice President, Operations and for business group costs that are not specifically related to any KBU.

5C.11.2 Overview of Operating Costs and FTEs

Table 5C-18 Business Unit Support KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Executive VP	1.2	0.0	0.8	0.0	0.0	0.0	0.0	**2.0**	3
2	Business Support	2.2	0.0	0.4	0.0	0.0	0.0	0.0	**2.6**	-
3	Waneta	0.0	0.0	6.4	0.0	0.0	0.0	0.0	**6.5**	-
4	**Total (Sch 5.3 L8+L12, Sch 16.0 L22)**	**3.5**	**0.0**	**7.6**	**0.0**	**0.0**	**0.0**	**0.0**	**11.1**	**3**

- The Executive VP department holds the labour budget for three FTEs: the Executive Vice-President of Operations, a Strategic Business Advisor and an administrative assistant. It also includes a labour and services budget to support BC Hydro's Stations Work Planning and Execution initiative.
- The Business Support department contains $1.9 million in labour costs for apprentices performing work in generation plants as well as labour costs for all Operations employees conducting union business for IBEW and MoveUp. These costs are invoiced to IBEW and MoveUp. This department includes the budget for BC Hydro's annual Safety Rodeo.
- The Waneta department contains the maintenance budget for the Waneta generating facility of which $3.8 million in costs are offset in Miscellaneous Revenue, as shown in Appendix A, Schedule 15.0.

5C.11.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5C-19 Business Unit Support KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.3 L8+L12	6.6	5.4	6.6	6.3	6.7	11.1	11.1	11.3
2	FTEs	16.0 L22	3	3	3	3	3	3	5	5

Operating costs are planned to remain constant from the fiscal 2019 forecast to the fiscal 2020 plan. Due to changes to BC Hydro's apprentice program, $1.9 million is being transferred from the Business Support KBU to the Stations Asset Planning and Stations Field Operations KBUs. This is offset by an increase of $1.9 million in maintenance costs at the Waneta generating facility, representing the first full year of ownership related to BC Hydro's purchase of the remaining two-thirds interest in that facility, as discussed in Chapter 4, section 4.2.3. These additional costs are offset through Miscellaneous Revenue, as shown in Appendix A, Schedule 15.0, line 21.

Operating costs are increasing by approximately $0.2 million from fiscal 2020 plan to fiscal 2021 plan due to cost increases under the terms of the Waneta agreement.

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Chapter 5D

Operating Costs

Safety

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5D.1 Introduction – Safety Business Group

Chapter 5D provides and explains in detail the composition of, and rationale for, the operating costs of the Safety Business Group. The Safety Business Group is one of six Business Groups in the organization and serves as a Support function of the Plan-Build-Operate-Support model.

The Safety Business Group budget was developed as part of the budgeting process outlined in Chapter 5, section 5.4. The information provided in this Chapter 5D demonstrates the basis for the entirety of the Business Group and KBU budgets, rather than focussing only on incremental cost requirements.

Chapter 5D is organized as follows:

- Section 5D.2 provides an overview of the organization and responsibilities of the Safety Business Group;
- Section 5D.3 provides the operating costs and FTE information for the Safety Business Group as a whole,[232] and
- Sections 5D.4 to 5D.8 provide more detailed information on the responsibilities, cost and FTEs for each KBU within the Safety Business Group. The operating costs and FTE information for each KBU is broken out into two sections:[232]
  - ▶ Overview of Operating Costs and FTEs – This subsection explains the starting operating costs and FTEs based on the fiscal 2019 forecast; and
  - ▶ Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs – This subsection explains any incremental changes between fiscal 2019 forecast and fiscal 2020 and fiscal 2021 plan.

[232] Please note the amounts presented in the tables in these sections may not add due to rounding.

5D.2 Overview of Safety Business Group Organization and Responsibilities

The Safety Business Group has a clear focus – we make it easier for people to work safely. The scope of this mandate includes employees, contractors, and the safety of the public. This Business Group provides safety support services, including training, skill development and overall physical security, so that every KBU in BC Hydro can perform their work safely.

The Safety Business Group consists of the following KBUs:

Business Group	Key Business Unit
Safety	Safety System and Assurance Learning and Development Field Safety Services Security and Emergency Management Business Unit Support

Since the Previous Application, the Learning and Development KBU has been added to the Safety Business Group from the previous Training, Development and Generation Business Group.

Between April 2005 and September 2012, BC Hydro employees suffered 15 permanent disabling injuries (approximately two per year). Between April 1999 and August 2010, there were eight fatalities (all electrical workers). Since August 2010, BC Hydro has had no employee fatalities. Three permanent disabling injuries have occurred in this time period. The decrease in fatalities and disabling injuries reflects BC Hydro's concerted effort to improve worker safety.

Despite a reduction in injuries and fatalities due to electrical worker accidents, BC Hydro continues to have a higher all injury frequency rate and lost time injury rate, compared to industry peers in the Canadian Electricity Association. Accordingly, BC Hydro's focus going forward is to reduce the frequency of other incidents leading to injury.

The figures below demonstrate the opportunity to further reduce worker injuries at BC Hydro as well as BC Hydro's progress on completing corrective actions on time and increasing the reporting of safety incidents.[233] Developing effective corrective actions and learning from reported incidents will lead to further improvements in safety performance over time.

Figure 5D-1 Lost Time Injury Frequency – Employees[234]

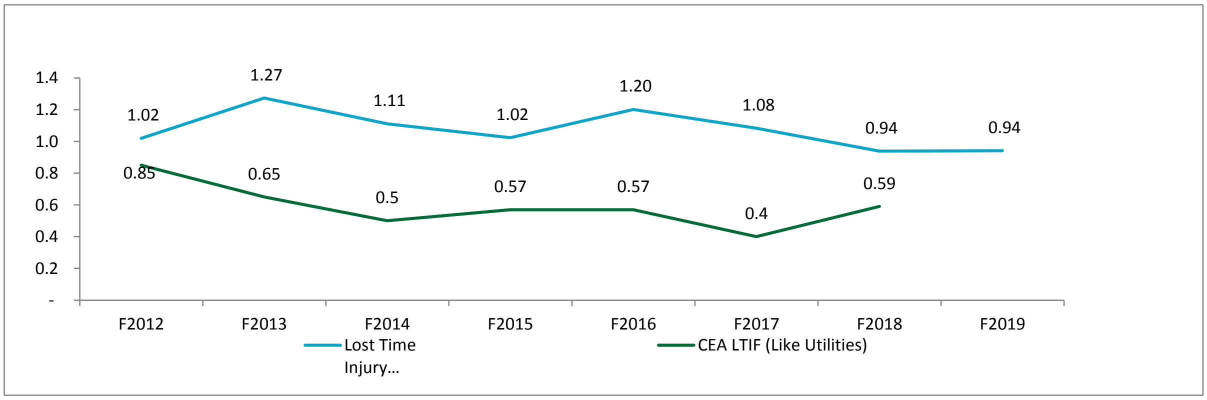
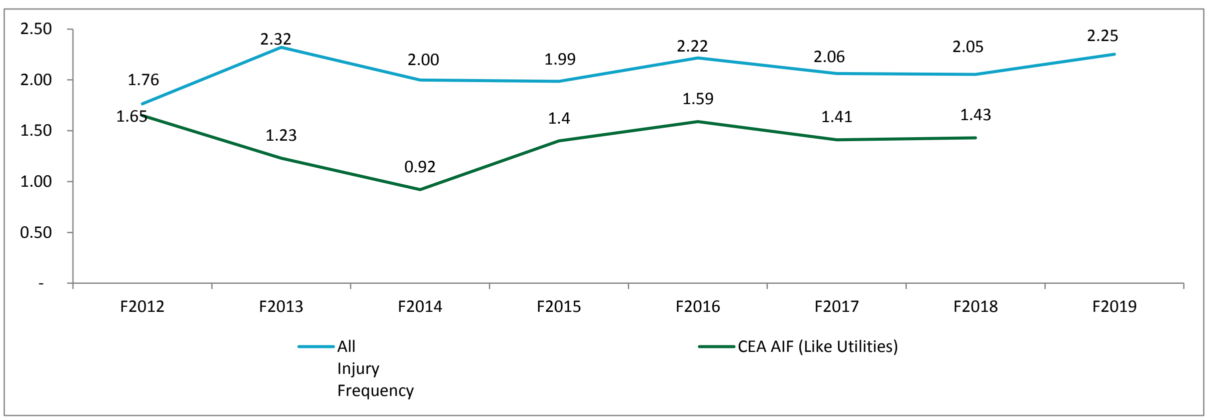


Figure 5D-2 All Injury Frequency – Employees[235]



[233] In the charts below, CEA LTIF includes a subset of companies with over 1,500 employees. This subset includes companies with a mix of generation, transmission, and distribution work, as well as construction.

[234] Lost Time Injury Frequency is determined by multiplying the number of Lost Time Injuries incurred, by 200,000 (to represent regular hours worked per employee in a year) and then dividing by the total number of hours worked in that period.

[235] All Injury Frequency is determined by multiplying the number of Lost Time Injuries and Medical Treatment Injuries incurred in a year, by 200,000 (to represent regular hours worked per employee in a year), then dividing by the total number of hours worked in that period.

Figure 5D-3 Corrective Actions Completed on Time[236]

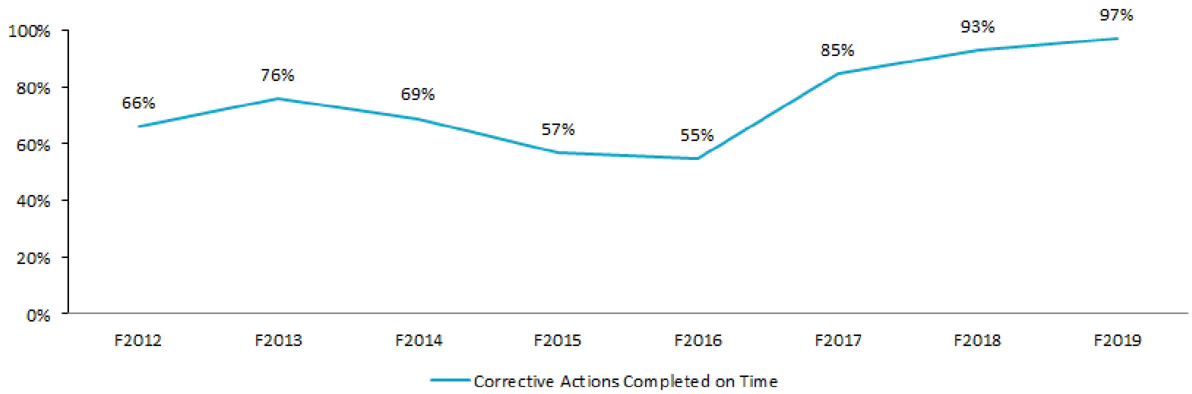
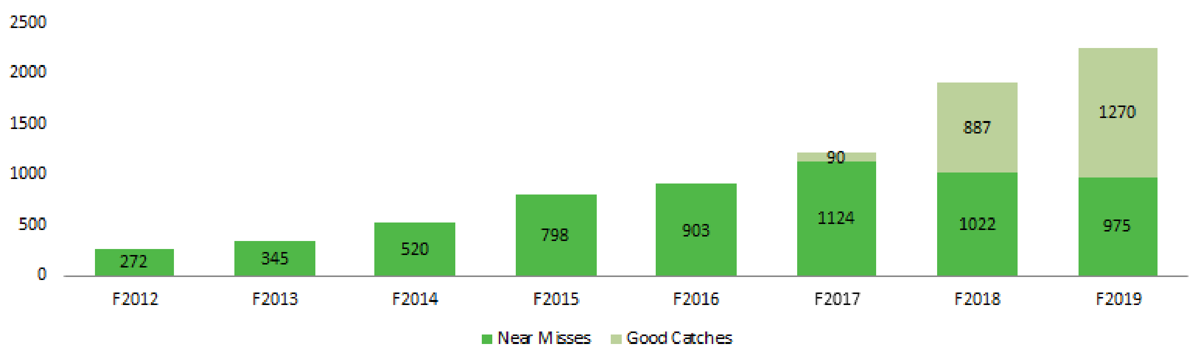


Figure 5D-4 Employee Near Miss / Good Catch Reporting[237]



Over the test period, BC Hydro plans to focus on the following key Safety initiatives:

- Investing in improvements to our Safety and Health Management System;
- Improving incident reporting;
- Building better corrective actions;
- Focusing on improvements to safe work observations;
- Improving safety documentation;

236 This percentage measures the percentage of corrective actions completed by the due date.

237 Good catches were piloted in fiscal 2016 and incorporated into BC Hydro's Incident Management System in fiscal 2017.

- Performing job hazard assessments of the work we do to improve training and procedures;
- Advancing worker ergonomics programs;
- Meeting NERC CIPv5 requirements, as discussed further in Chapter 5C, section 5C.10.3;
- Focusing on contractor safety to support our capital program; and
- Dedicating resources to support confined space entry work, consistent with regulatory requirements.

In a large and complex organization like BC Hydro, the most effective way to deliver a safety program consistently and effectively is to build it into a management system. Our Safety and Health Management System provides a framework and a set of consistent program elements as well as supporting processes and documents. These elements integrate people and processes to keep workers safe and meet internal and regulatory safety and health requirements. When integrated into daily activities, the Safety and Health Management System contributes to BC Hydro's long-term success by:

- Clearly communicating the organization's accountabilities and responsibilities for safety and health;
- Improving our management and control of safety and health risks from planning to work execution;
- Making it easier for workers to get the information and support they need to do their jobs safely;
- Improving our culture by integrating safety and health in everything we do; and
- Improving safety and health performance through continual improvement.

Figure 5D-5 below provides a visual representation of the Safety and Health Management System.

Figure 5D-5 Safety and Health Management System

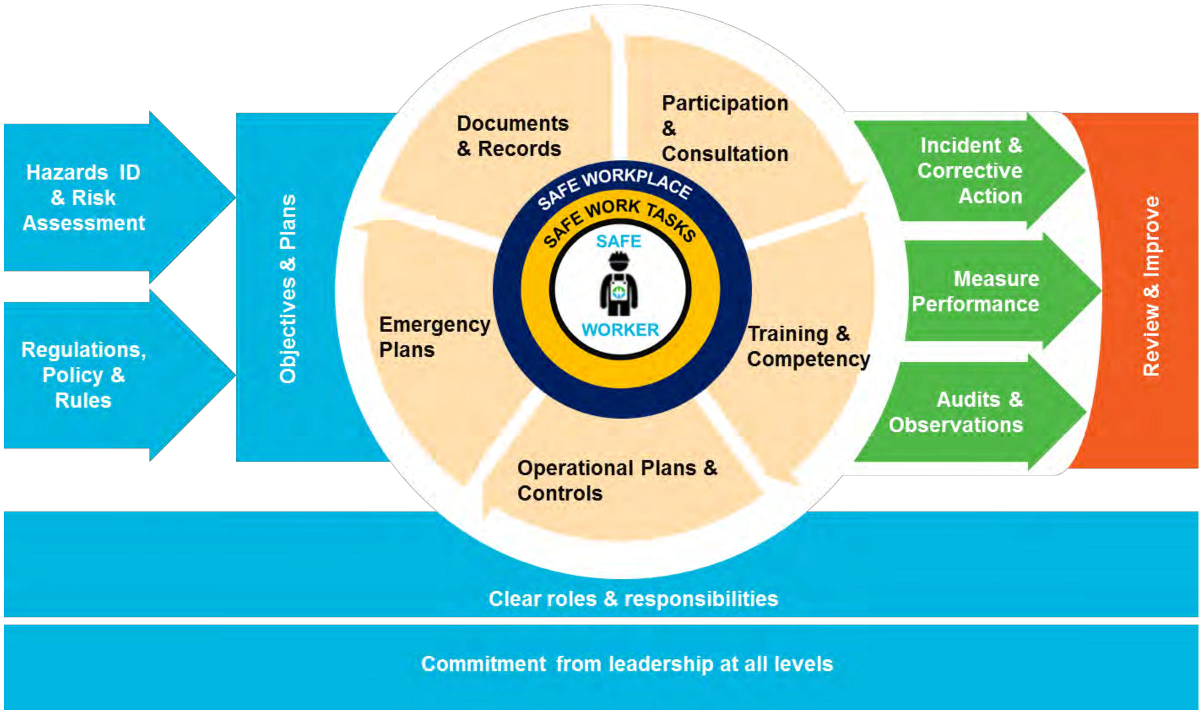


Figure 5D-6 below provides further detail on each of the elements of the Safety and Health Management System.

Figure 5D-6 Diagram of the 14 Elements That Make up the BC Hydro Safety Management System

	Element	Purpose	Teams/Departments
Plan	Leadership and Commitment	Safety is a core value supported at every level by our policies and actions.	Executive Team Safety System and Assurance
	Roles, Responsibilities, and Accountabilities	Everyone is clear about their function to work safely.	Worker Safety Programs Learning and Development
	Hazard Identification and Risk Assessment	All hazards are identified, and informed risk decisions are made at the right level.	Process Safety and Regulatory Risk Management Field Safety Services Learning and Development
	Legal and Other Requirements	Regulations and rules are identified, interpreted and integrated into clear work procedures.	Process Safety and Regulatory Risk Management Worker Safety Programs Field Safety Services
	Goals, Objectives and Plans	Improving the right things at the right time with the right people.	Safety Planning Analytics Field Safety Services
Do	Training and Competency	Relevant and timely training, verified competency, available to workers.	Learning and Development Field Safety Services
	Participation, Consultation and Communication	Empowering workers to be involved and be heard.	Safety Planning Analytics Worker Safety Programs Field Safety Services
	Document Control and Records Management	Easy access to clear, current, concise and relevant safety information.	Worker Safety Programs
	Operational Planning and Control	Workers are provided what they need to manage risk and meet safety requirements.	Worker Safety Programs Process Safety and Regulatory Risk Management Learning and Development Field Safety Services
	Emergency Preparation and Response	Workers are equipped for an emergency with plans, training and supplies.	Emergency Management
Check	Incident, Non-Conformity, and Corrective Action	Incidents, near misses, good catches are reported and learnings lead to systemic improvement.	Safety Incident Management Field Safety Services
	Performance Monitoring and Measurement	Check our performance against our goals and objectives to see if we have, or can improve.	Safety Planning Analytics
	Audit and Assurance	Check to confirm we are doing what we said we must.	Safety Audits Field Safety Services Learning and Development
Act	Management Review and Continual Improvement	Senior leaders are accountable to respond to safety performance and support improvement opportunities.	Executive Team Safety System & Assurance

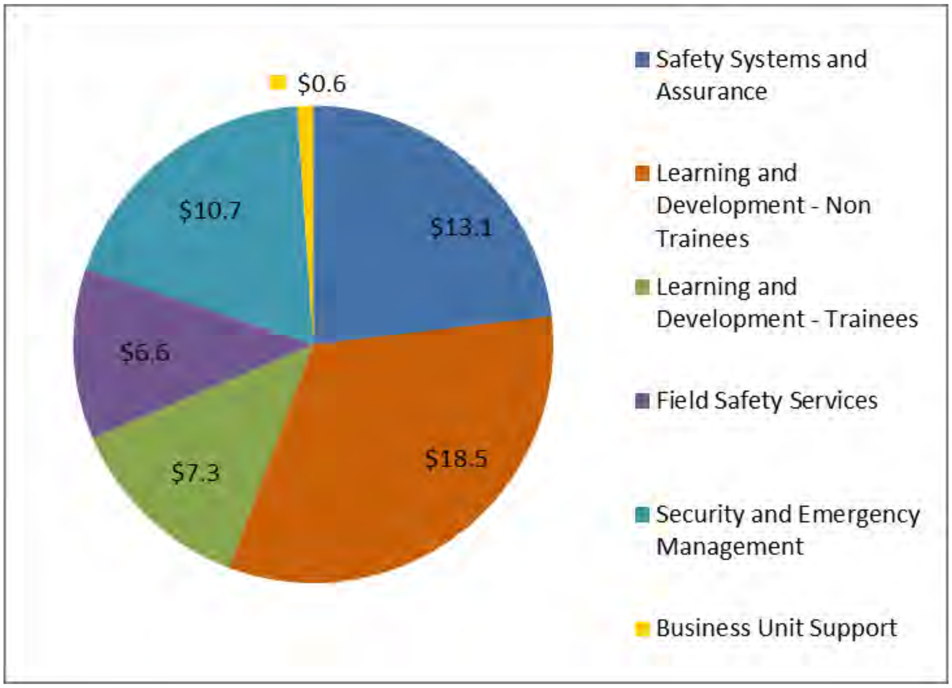
5D.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTE Summaries.

This section addresses planned operating costs and FTEs for the Safety Business Group. The following are some key points of note with respect to the information provided in Figure 5D-7, Table 5D-1 and Figure 5D-8, Table 5D-2 and Table 5D-3:

- The Field Safety Services KBU (25 per cent) and the Learning and Development KBU (45 per cent), charge out a significant portion of their labour costs to maintenance and capital work programs;
- Apprentices and trainees FTEs reside in the Learning and Development KBU and comprise over 45 per cent of the total FTEs in the Safety Business Group. These FTEs represent only 13 per cent of the total operating budget for the Safety Business Group because they charge out their labour to maintenance and capital work programs. Major categories for the apprenticeship and trainee roles include Power Line Technicians, Electricians, Mechanics, Utility Fleet Mechanics, Distribution Design and Customer Connect technologists, Communication Protection and Control technologists and Engineers; and
- Operating cost increases from fiscal 2019 forecast to fiscal 2021 plan are primarily driven by increases to Standard Labour Rates (discussed further in Chapter 5, section 5.5.2.2) as well as NERC CIPv5 requirements (discussed further in Chapter 5C, section 5C.10.3).

Planned operating costs for the Safety Business Group are approximately $56.8 million in fiscal 2020 and approximately $57.5 million in fiscal 2021. The operating costs for the Safety Business Group are summarized by KBU in Figure 5D-7. Additional cost details are provided in Table 5D-1 below.

1 **Figure 5D-7 Safety Net Operating Costs by KBU**
2 **(Fiscal 2020 Plan) ($ million)**



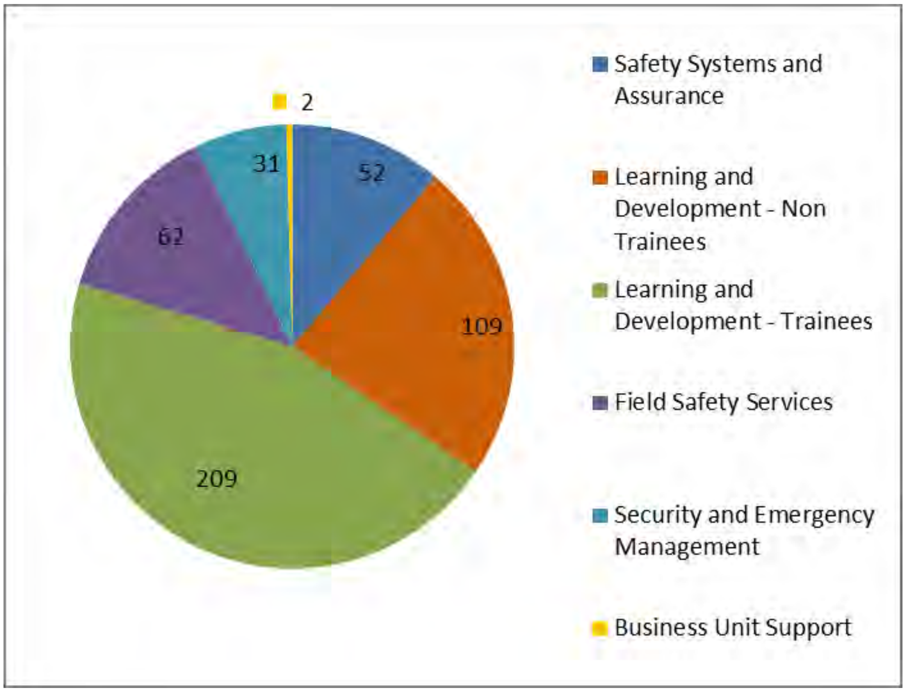
3 **Table 5D-1 Safety Net Operating Costs by KBU[238]**

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Safety Systems and Assurance	5.4 L1	14.9	14.5	14.8	14.7	14.7	12.9	13.1	13.3
2	Learning and Development	5.4 L2	25.0	25.7	25.0	23.2	25.4	25.5	25.8	26.2
3	Field Safety Services	5.4 L3	4.9	5.7	5.0	5.7	5.1	6.2	6.6	6.7
4	Security and Emergency Management	5.4 L4	9.3	9.4	9.3	9.2	9.3	9.6	10.7	10.8
5	Business Unit Support	5.4 L5	0.5	0.6	0.5	0.6	0.5	0.6	0.6	0.6
6	Total	5.4 L12	54.6	55.9	54.6	53.3	54.9	54.8	56.8	57.5

4 The FTEs for the Safety Business Group are summarized by KBU in Figure 5D-8.
5 Additional details are provided in Table 5D-2 below.

238 Learning and Development budget and FTEs include apprentices and trainees. Please refer to Chapter 5D, section 5D.5.2.7 for details.

1 **Figure 5D-8 Safety FTEs by KBU (Fiscal 2020 Plan)**



2 **Table 5D-2 Safety FTEs by KBU**

	(FTEs)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Safety Systems and Assurance	16.0 L24	52	48	52	49	52	52	52	52
2	Learning and Development	16.0 L25	438	456	438	437	438	358	317	300
3	Field Safety Services	16.0 L26	53	50	55	56	55	63	62	62
4	Security and Emergency Management	16.0 L27	18	20	18	25	18	26	31	31
5	Business Unit Support	16.0 L28	2	2	2	2	2	2	2	2
6	Total	16.0 L29	563	576	565	568	565	501	464	447

Table 5D-3 below provides a continuity table which highlights changes to the Safety Business Group from the Previous Application. An overall discussion of these changes, at a company-wide level, is provided in Chapter 5, section 5.5.2. Further details, by KBU, are provided in the sections below.

Table 5D-3 Safety Operating Costs Continuity Schedule

	($ million)		F2020 Plan	F2021 Plan
1	F2019 Revenue Requirement Application Plan		-	
2	Reorganization Impacts		54.9	
3	F2019 Revenue Requirement Application Plan (Safety)		54.9	
4	Budget Transfers Between Business Groups		(0.2)	
5	Adjusted F2019 Revenue Requirement Application Forecast (Safety) / carry forward plan (Schedule 5.4, line 12)	A	54.8	56.8
6	Current Year Budget Transfers Between Business Groups	B	0.7	
7	Test Period Savings			
8	Vacancy factor savings		(0.2)	
9	Miscellaneous savings		(0.4)	
10		C	(0.6)	-
11	Test Period Cost Increases			
12	Labour		1.9	0.7
13		D	1.9	0.7
14	Test Period Net Increase/(Decrease)	E=C+D	1.3	0.7
15	Net Operating Costs (Schedule 5.4, line 12)	A+B+E	56.8	57.5

5D.4 Safety System and Assurance KBU

5D.4.1 Responsibilities

The Safety System and Assurance KBU develops and implements the elements of the Safety and Health Management System, consistent with the requirements of the ISO 45001 standard. This provides a structured, consistent and disciplined system for managing health and safety risk across BC Hydro and for supporting continual improvement.

This Key Business Unit consists of the following departments:

- Office of the Director of Safety Assurance Department;
- Safety Planning, Analytics and Incident Management Department;
- Process Safety and Regulatory Risk Management Department; and
- Worker Safety Programs Department.

5D.4.1.1. Office of the Director of Safety Assurance Department

In addition to overall management of the KBU, this department is responsible for:

- Introducing safety programs into worker processes to increase the safety of workers and reduce regulatory compliance risk; and
- Completing safety audits to assess BC Hydro's compliance with occupational health and safety requirements as well as the effectiveness of programs, procedures and corrective actions. These field-focused audits support quality assurance and system improvements by comparing regulatory and internal requirements with observed practices in the field. The findings from these audits lead to corrective actions that improve programs as well as the overall Safety and Health Management System.

5D.4.1.2. Safety Planning, Analytics and Incident Management Department

This department includes the following three teams:

- The Safety Systems and Business Planning team is the owner of the Safety Incident Management System[239]. The team provides support, subject-matter expertise, prioritization of requests, governance, business enhancements, and daily operations of the system. This team also provides support and content management for the Qualification and Learning Management System[240] and leads the BC Hydro Safety Business Planning process. Both of these systems are key components of the overall Safety and Health Management System;
- The Safety Analytics team produces analytical reports on Safety performance. The team analyzes lagging indicators to review past performance, as well as leading indicators to identify and highlight potential risks based on common incidents. The team liaises with other utilities and is an active member of the Canadian Electricity Association to benchmark analytics across Canadian

[239] The Safety Incident Management System (**IMS**) is a module of SAP, employed company-wide to report, investigate, and communicate safety incidents, and to document and track completion of related corrective actions.

[240] The Qualification and Learning Management System is an Enterprise Learning Management System used to deliver, access, schedule and report on training activities. It is also used to manage employee qualifications.

utilities and participates in joint activities to identify trends and proactively address changing safety risks in the industry; and

- The Safety Investigators team triages all safety incidents (injuries, near miss and good catch events) that occur at BC Hydro, provides subject matter expertise to assist field managers with simpler investigations, leads the incident investigation process for complex investigations and ensures corrective actions address root causes and WorkSafeBC requirements. When appropriate, the team also conducts more in-depth safety investigations for specific BC Hydro incidents to determine if additional learnings can be acquired and shared across the company.

5D.4.1.3. Process Safety and Regulatory Risk Management Department

This department includes the following five teams.

The Policy and Regulations team manages BC Hydro's relationship with safety regulators. This includes:

- Monitoring and influencing changes to regulators' policies and regulations;
- Maintaining the Safety Risk Profile, which assesses the risk to BC Hydro workers from the 61 hazards identified at BC Hydro workplaces; and
- Coordinating and supporting efforts throughout BC Hydro to address regulatory orders as well as supporting appeals and variance applications to safety regulators;

The Public Safety team is responsible for increasing public awareness of electrical safety at home, at work and in the community. The team also conducts risk assessments and oversees the implementation of public safety control measures at our dams and in public use management areas. This team works closely with the Dam Safety KBU. The public safety team minimizes the risk to the public caused by the operations of BC Hydro's facilities while the Dam Safety KBU is accountable for the safety of BC Hydro's dams under both normal and extreme conditions.

The Fire Risk Management team is responsible for developing and maintaining a program to assess fire related risks, including wildfires, as well as providing technical support, governance and assurance functions. The team supports the organization in meeting its obligations under the Wildfire Act and acts as the internal authority, providing expert advice and support on other fire-related topics. The team works closely with the Program and Contract Management KBU, the Security and Emergency Management KBU and the Engineering KBU to collectively manage this cross-organizational risk.

The Safety Engineering and Risk Management team provides risk assessments of various safety related business process, broader Occupational Health and Safety topics, as well as unique and challenging safety issues on capital projects and asset management programs. This team also provides governance, advice and support to key safety functions such as Safety by Design,[241] Job Hazard Assessments[242] and human factors, and other technical safety issues. The engineers on this team have various formal disciplines and are included in this KBU rather than the Engineering KBU, given their expertise in human factors, ergonomics and safety.

The Work Methods team is responsible for the development and maintenance of clear, safe work procedures and evaluation of tools used by BC Hydro for some of the highest risk work on the Power System (i.e., energized/de-energized work, fall hazards, arc flash). The team supports the Operations Business Group, responding to questions regarding work procedures and rules and works with vendors to evaluate new tools and equipment to improve the safety and efficiency of the procedures. The group also reviews proposed capital project designs (with respect

[241] Safety by Design is an application of engineering principles and standards for designing features into new and existing facilities to ensure that they are inherently safe.

[242] Job Hazard Assessment is a technique to identify potential hazards present in the steps of a task or job and recommend mitigations so that each step is safe.

to energized and de-energized workability) so that BC Hydro has the appropriate work procedures and tools in place to build, operate, maintain and repair new assets.

5D.4.1.4. Worker Safety Programs Department

This department provides oversight of the governance model used for all safety programs and includes the following two teams:

- The Worker Safety Programs team collaborates with other departments to deliver a range of projects and programs to improve safety at BC Hydro, such as the Field Access to Safety Information,[243] as well as the Contractor Safety Program,[244] and
- The Occupational Safety and Hygiene team translates safety regulation and business decisions into programs for complex topics (such as asbestos or hazardous materials) that support safety management across BC Hydro's KBUs. This team also provides occupational hygiene and ergonomics expertise and advice to the Operations Business Group and the Field Safety Services KBU.

5D.4.2 Overview of Operating Costs and FTEs

Table 5D-4 Safety Systems and Assurance KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Director Safety Assurance	1.1	0.0	0.1	0.0	0.0	0.0	0.0	**1.3**	6
2	Safety Planning, Analytics and Incident Mgmt	1.7	0.0	0.1	0.0	0.1	0.0	0.0	**1.9**	14
3	Process Safety and Regulatory Risk Mgmt	2.9	0.0	2.4	0.0	0.0	0.0	0.0	**5.4**	19
4	Worker Safety Programs	1.9	0.0	2.5	0.1	0.0	0.0	0.0	**4.4**	13
5	**Total (Sch 5.4 L1, Sch 16.0 L24)**	**7.6**	**0.0**	**5.1**	**0.1**	**0.1**	**0.0**	**0.0**	**12.9**	**52**

[243] Field Access to Safety Information is an initiative to separate rules and procedures, make them easier to find, and to improve the quality of safety information.

[244] The Contractor Safety Program is an initiative to provide a systematic and consistent approach to ensuring BC Hydro meets its Owner duties, as described in the *Workers Compensation Act* part 119, for safety in contracted work.

5D.4.2.1. Office of the Director of Safety Assurance Department

The majority of this department's budget relates to labour costs for six FTEs:

- Four FTEs represent the Director of the Safety Assurance KBU and an administrative assistant as well as a project manager and support staff who are responsible for improving the implementation of safety programs within BC Hydro (e.g., confined space, asbestos); and
- Two FTEs are trained auditors who complete a total of three to four safety audits each year and coordinate audit findings across the organization. Each audit takes three to four months to complete and typically involves visiting more than 10 sites across the BC Hydro system and conducting many interviews. These audits are focused on safety and on practices observed in field, which is different than the audits performed by the Internal Audit department of the Finance KBU. These audits support the Audit and Assurance element of the Safety and Health Management System.

5D.4.2.2. Safety Planning, Analytics and Incident Management Department

The majority of this department's budget relates to labour costs for 14 FTEs as follows:

- One FTE is the department manager;
- Three FTEs on the Safety Systems and Business Planning team. This team administers the Incident Management System, which receives over 6,000 entries per year as well as the Learning Management System, which tracks and administers more than 900 courses. The team is also responsible for the development of BC Hydro's annual safety plan;
- Five FTEs are Safety Analysts on the Safety Analytics team. All safety and learning analytics are provided through this team including monthly dashboards for each KBU and regular reports to BC Hydro's Executive Team and Board of Directors; and

- Five FTEs are Safety Incident Investigators who triage an average of 3,000 employee good catches, near misses and injuries per year and support managers after an incident to perform incident investigations and complete corrective actions so that WorkSafeBC requirements are met. The team also participates in the development and implementation of complex corrective actions.

5D.4.2.3. Process Safety and Regulatory Risk Management Department

This department's labour budget represents costs related to 19 FTEs as follows:

- One FTE is the department manager;
- Four FTEs provide governance of public safety programs related to safety around water and electricity. These FTEs oversee adherence to the Canadian Dam Association Guidelines for Public Safety around Dams and Waterways. They also conduct approximately 22 field risk assessments and implement controls to 65 public use areas and generation facilities each year. These FTEs also coordinate electrical safety awareness training and communications to the public, high risk trades and first responders. In fiscal 2018, this training was delivered to 9,679 members of the public and trades as well as over 10,000 elementary and high school students. These FTEs also provide outreach at approximately 25 trades safety events per year and are responsible for BC Hydro's 19 Public Use Management Areas[245] which have a total of approximately 1.7 million visitors annually. The operating costs for BC Hydro's Public Use Management Areas were $1.03 per visitor day in fiscal 2019 which compares favorably to operating costs of B.C. Parks;[246]

[245] Public Use Management Areas are recreational facilities owned and operated by BC Hydro to manage public use and safety around reservoirs and redirect the public away from hazards associated with generating assets to sites under BC Hydro control where these hazards are managed.

[246] BC Parks operating costs/visitor days in most recent annual report is $2.17 or $1.16 after accounting for revenues from user fees. (see: http://www.env.gov.bc.ca/bcparks/research/statistic_report/statistic-report-2015-2016.pdf?v=1547851037669).

- Two FTEs are Regulatory Risk Management professionals who are primarily responsible for managing BC Hydro's relationship with WorkSafeBC. They monitor WorkSafeBC policy and regulations as well as over 30 additional safety-related Acts and regulations to identify, communicate and oversee regulatory changes. The team responds to over 140 requests each year for regulatory interpretations or risk analysis and supports the assessment and response to over 30 regulatory inspection reports and five to 10 regulatory orders, variances, or appeals annually;
- Two FTEs are Fire Risk Management professionals. These FTEs advise approximately 25 capital projects with more complex fire risk management requirements each year. They also develop or revise fire safety plans for approximately 25 BC Hydro properties and stations annually. In addition, these FTEs provide tactical support for major fires, requiring approximately five to 10 follow-up investigations each year. The team also provides support to other fires that impact our system annually (e.g., wildfires);
- Five FTEs provide safety risk assessment leadership and support to BC Hydro. This includes participation in and quality control assessment of 30 to 35 capital projects per year through the Safety by Design process, development of the Job Hazard Assessment process (26 Job Hazard Assessments were produced in fiscal 2018), and the development and annual update of the BC Hydro Safety Profile. This team also performs an average of six risk assessments per year on complex, high risk topics where specialist expertise is required and maintains 46 safety equipment specifications. Lastly, the team is developing and will be responsible to maintain a set of Human Factors design standards for the Engineering KBU; and
- Five FTEs are engineers in the Work Methods team. This team reviews and updates approximately 70 existing safe work procedures each year and

develops approximately 10 new procedures each year to address gaps as well as changes to regulations and standards.

The $2.4 million in non-labour costs for this department include $1.7 million for the operation of Public Use Management Areas, with the remainder funding public safety communications as well as consultants to support Fire and Public Safety work.

5D.4.2.4. Worker Safety Programs Department

This department's labour costs represent 13 FTEs as follows:

- Two FTEs represent a department manager and an administrative assistant;
- Five FTEs deliver safety projects that improve and sustain processes to enable frontline workers and others to receive and use safety and hazard information. This includes maintaining and improving the SafeHub[247] document management system which contains over 2,100 documents and ensuring effective governance for the 200 documents that are added, updated or removed from the system each year; and
- Six FTEs lead the development and implementation of formal safety programs (e.g., asbestos and other hazardous materials, ergonomics, fall protection, confined space, storage rack safety, and winter safety). These safety programs are in place so that BC Hydro protects workers and meets regulatory requirements to manage and control worker exposure to hazardous materials such as asbestos as well as hazards such as confined spaces and falling from heights.

This department's non-labour costs are primarily allocated to the Field Access to Safety Information project which aims to standardize, simplify and separate rules from procedures. This multi-year effort will make it easier for our workers to find the

[247] Safehub is an online and offline (via an App) available compilation of all safety documentation. A significant amount of document cleanup and removal of duplication/conflicting documents was undertaken (and is ongoing) to populate the Safehub repository.

information they need to work safety and efficiently and reduce document administration burden. This project responds to the top concern raised in over 500 interviews with BC Hydro employees regarding safety issues and is following guidance from a WorkSmart process that BC Hydro conducted to identify opportunities to improve efficiency. The project costs primarily consist of consultants and cross-charges by subject matter experts from other departments.

5D.4.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5D-5 Safety System and Assurance KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.4 L1	14.9	14.5	14.8	14.7	14.7	12.9	13.1	13.3
2	FTEs	16.0 L24	52	48	52	49	52	52	52	52

Operating costs are increasing by approximately $0.2 million from the fiscal 2019 forecast to the fiscal 2020 plan and by approximately $0.2 million from the fiscal 2020 plan to the fiscal 2021 plan, due to Standard Labour Rate increases. FTEs are planned to remain constant.

5D.5 Learning and Development KBU

5D.5.1 Responsibilities

The Learning and Development KBU leads the training and competency element of the Safety and Health Management System and supports the other elements of the system. It oversees the ongoing sustainment of a trained, competent and qualified workforce at BC Hydro, addressing the needs of existing workers and providing technical training for new workers (apprentices, engineers-in-training and trainees). This KBU enables the continuous improvement of electrical safety through projects, training, mentorship and coaching.

Learning and Development applies the 70-20-10 learning model where 70 per cent of learning is on the job, 20 per cent is through relationships like coaching and mentoring and 10 per cent is through attendance at courses. This KBU also applies an industry standard model for training course content development that includes analyzing, designing, developing, implementing and evaluating courses and curriculum. This includes trades, technical, safety, leadership, professional development, regulatory and corporate compliance training.

Most of the Learning and Development KBU resides at the Trades Training Centre, which was built in 2013 to meet the unique training requirements of BC Hydro, as a major electric utility. Located on BC Hydro's Surrey Campus, the Trades Training Centre provides the only hands-on training facility within British Columbia for many of our critical trades such as Communication Protection and Control Technologists and Power Line Technicians. It is also the only approved location within British Columbia to provide the Industry Training Authority approved Red Seal Apprentice Power Line Technician program. The Trades Training Centre now serves as a training and meeting facility for the entire BC Hydro workforce.

The Learning and Development KBU's responsibilities have changed since the Previous Application. Electrical Safety Programs and Safety Advocates have been added to this KBU. The management and strategy of leadership and professional development training programs has been transferred to the Human Resources KBU while support for scheduling and logistics, course development and training records management for leadership and professional development remains within the Learning and Development KBU.

The Learning and Development KBU includes the following departments that support employee learning across BC Hydro in both regional locations and the Trades Training Centre in Surrey:

- Electrical Safety Programs Department;
- Learning Governance and Planning Department;
- Safety Training and Learning Quality Assurance Department;

- Training Operations Department;
- Technical and Trades Training Department; and
- Trainees Department.

5D.5.1.1. Electrical Safety Programs Department

This department is responsible for developing electrical safety programs and worker protection systems[248] and depends on resources throughout the Learning and Development KBU for implementation. This group is different from the Worker Safety Programs department in the Safety Systems and Assurance KBU which is responsible for non-electrical safety projects and relies on the Field Safety Services KBU for implementation.

The Electrical Safety Programs department was formed in response to 21 electrical contact incidents that occurred between fiscal 2006 and fiscal 2016. To improve the safety of BC Hydro employees and contractors this department provides a framework to identify hazards and apply appropriate barriers. This department also maintains authorization records of both employees and contractors, identifying who can work safely on BC Hydro's Power System. It is responsible for maintaining the rules, procedures, documents and information technology applications specific to the worker protection systems.

5D.5.1.2. Learning Governance and Planning Department

The Learning Governance and Planning department coordinates, plans and schedules training. It also maintains training records and works with KBUs across BC Hydro to develop and implement learning policies.

5D.5.1.3. Safety Training and Learning Quality Assurance Department

The Safety Training and Learning Quality Assurance department includes two teams.

[248] See Section 5D.5.2.2 for description of Worker Protection Systems.

The Safety Training team provides access to training which is required by regulation through a combination of internal trainers, external contractors and resources in the Field Safety Services KBU, so that employees can work safely and achieve regulatory compliance.

The Learning Quality Assurance team is responsible for BC Hydro's learning quality assurance strategy which includes establishing processes and standards for courses and curriculum for both internally and externally developed content. The team develops and maintains electrical utility specific courses and curriculum for a number of subjects such as technical and trades training, safety training, business application support, and distribution design. They also perform quality checks on externally developed content. Once courses are developed by this team, the Safety Planning, Analytics and Incident Management team uploads and administers the courses in the Learning Management System.

5D.5.1.4. Training Operations Department

This Training Operations Department includes two teams.

The first team manages the day-to-day operations of the Trades Training Centre facility. Management includes the maintenance and operation of eight classrooms, four trade specific labs, three workshops, a training pole yard, a chainsaw training area, confined space and fall protection training structures and an outdoor covered training space.

The second team provides centralized administrative and contract support to the Learning and Development KBU.

5D.5.1.5. Technical and Trades Training Department

There are three teams within this department.

The first team is made up of instructors who deliver trade and technical specific training in the classroom and on the job. They serve as subject matter experts in the development of training, work methods and procedures and support implementation of electrical safety projects. This team supports roles such as Power Line Technicians, Cable Splicer, Generation and Stations Electricians, Mechanics and Communications Protection and Controls Technologists.

The second team is made-up of Safety Advocates. The Safety Advocate role was established in 2012 in response to a high number of serious safety incidents. Safety Advocates work in the field with employees to resolve electrical safety issues and implement electrical safety projects. The training delivered by the trades instructors is reinforced by the Safety Advocates through in field coaching and mentoring. They also assist the Work Methods team in developing work procedures. The field observations made by this group are used throughout BC Hydro to identify additional learning and management intervention opportunities.

The third team manages the apprentice and trainee programs which are structured programs that develop and qualify employees in critical occupations. Apprentices and trainees are hired based on resource strategies, which consider attrition and future needs. These employees will enter the BC Hydro workforce once they graduate from their respective multi-year program. This team provides program management and subject matter expertise for curriculum development and coordinates with trades instructors to comply with Industry Training Authority[249] requirements, including Red Seal certification for the Apprentice Power Line Technician program. BC Hydro is the only qualified institution in British Columbia to provide this program.

5D.5.1.6. Trainees Department

This department holds the FTEs and budget for 10 Apprentice Programs, three Technical Trainee Programs and the Engineers-in-Training Program. However, the

[249] The Industry Training Authority (**ITA**) leads and coordinates British Columbia's skilled trades system. The ITA works with BC Hydro to set program standards and issue certifications for trades.

Trainees department labour budget only holds the training time for these FTEs as they charge out the majority of their time to maintenance and capital work programs.

5D.5.2 Overview of Operating Costs and FTEs

Table 5D-6 Learning and Development KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Training and Development Leadership	0.4	0.0	0.5	0.0	0.0	0.0	0.0	**0.9**	2
2	Electrical Safety Programs	0.7	0.0	1.3	0.0	0.0	0.0	0.0	**2.0**	4
3	Learning Governance and Planning	1.1	0.0	0.0	0.0	0.0	0.0	0.0	**1.2**	13
4	Safety Training and Learning Quality Assur.	2.1	0.0	1.3	0.0	0.0	0.0	0.0	**3.4**	19
5	Training Operations	0.8	0.0	0.1	0.3	0.1	0.0	0.0	**1.2**	8
6	Technical and Trades Training	7.9	0.0	1.0	0.0	0.1	0.0	0.0	**9.0**	62
7	Trainees	5.4	0.0	2.2	0.2	0.0	0.0	0.0	**7.8**	250
8	**Total (Sch 5.4 L2, Sch 16.0 L25)**	**18.4**	**0.0**	**6.4**	**0.5**	**0.2**	**0.0**	**0.0**	**25.5**	**358**

To meet BC Hydro’s learning needs, the Learning and Development KBU supplements internal resources with contracted services and resources. Decisions on how to allocate training between internal and external providers are generally based on utility-specific knowledge, cost, efficiency and subject matter expertise.

5D.5.2.1. Training and Development Leadership Department

This department’s labour costs are related to two FTEs – the Director of the Learning and Development KBU and an administrative assistant.

This department’s non-labour budget includes $0.1 million for supplemental labour resources across the KBU to respond to work peaks and $0.3 million for additional training requirements and developing contractor training governance and for unplanned work arising from incident investigations.

5D.5.2.2. Electrical Safety Programs Department

This department’s labour costs are related to four FTEs. Two FTEs manage the electrical safety projects. The other two FTEs manage BC Hydro’s worker protection systems - Power System Safety Protection[250] and Worker Protection Practices[251]. Currently there are over 18,000 workers, consisting of both employees and contractors, authorized to work on BC Hydro's Power System. For Worker Protection Practices, these FTEs conduct six to eight reviews per year resulting in every generation facility being inspected every three years. The Power System Safety Protection program receives one major review per year, with each region being inspected every four years.

This department's non-labour budget includes funding for projects to support electrical safety programs.

5D.5.2.3. Learning Governance and Planning Department

The majority of this department's budget relates to labour costs for 13 FTEs who provide training coordination services. These FTEs process approximately 1,800 training requests for safety, trades, technical, leadership and professional development, resulting in approximately 4,000 classroom sessions each year. In addition, these FTEs maintain employee training records in the learning management system and centrally manage the scheduling of training resources, including 100 contracted instructors. Lastly, these FTEs arrange logistics and scheduling for over 200 apprentices and trainees.

5D.5.2.4. Safety Training and Learning Quality Assurance Department

The majority of this department's budget relates to labour costs for 19 FTEs as follows:

- One FTE is the department manager;

[250] Power System Safety Protection (**PSSP**) defines the constraints applied to the Power System to provide safety protection from Power System hazards during prescribed work on transmission and distribution lines and in substations. .

[251] Work Protection Practices (**WPP**) are the rules and procedures that govern how equipment at generating stations and associated facilities are isolated from potentially hazardous sources of energy and made safe to work on.

- Five FTEs lead and support the Safety Training program and its pre-qualified external trainers. The average BC Hydro non-field employee is required to take approximately six hours of one-time training and the average field employee is required to take approximately 40 hours of one-time training. Additional safety training is driven by regulated re-training requirements, competency gaps, career progression and exposure to hazards and new equipment. In fiscal 2018 approximately 1,800 safety training sessions were delivered across BC Hydro; and
- 13 FTEs are responsible for creating new courses and maintaining approximately 400 classroom and 100 online courses for trades and technical, safety and business application systems topics. In fiscal 2018, the team developed over 45 new courses and updated over 25 existing courses. These courses vary in length from 30 minutes to five days.

This department's non-labour budget primarily provides funding for approximately 40 contracts with pre-qualified safety trainers to provide training requirements.

5D.5.2.5. Training Operations Department

The majority of this department's budget is related to labour costs for eight FTEs at the Trades Training Centre.

- Two FTEs oversee the Trades Training Centre and its $0.8 million capital budget as well as manage a $0.5 million operating budget for centralized tools and equipment to maintain the facility and onsite courses and program; and
- Six FTEs provide administrative support for all Learning and Development employees and help operate the Trades Training Centre. They also arrange travel logistics, tools and equipment purchases for approximately 45 trades instructors, 10 Safety Advocate FTEs and two Fleet Safety trainer FTEs. In addition, the department processes payments for external apprentices and administers over 100 external learning contracts.

5D.5.2.6. Technical and Trades Training Department

The majority of this department's budget is for labour costs related to 62 FTEs as follows:

- One FTE represents the department manager;
- 45 FTEs provide trades training, building trade-specific skills and knowledge for approximately 2,100 field employees and front line managers at BC Hydro. A benchmarking exercise conducted in fiscal 2018 by Mosaic Consulting indicates that this number is aligned to the utility industry norm of approximately one training staff for every 50 trades employees. To support front line employee knowledge retention and application, this team spends approximately 65 per cent of its billable time on course delivery, on the job training and conducting assessments. In fiscal 2018, this team delivered over 800 trade specific classroom sessions and from April 2018 to December 2018, instructors have provided over 8,500 on the job training hours to field workers. This team spends the remaining 35 per cent of its billable time serving as subject matter experts for course development and work procedures, working groups and projects;
- 10 FTEs represent Safety Advocates. From April 2018 to December 2018, Safety Advocates spent over 3,000 person hours in the field responding to crew and manager requests for coaching, field visits and attending work planning and safety meetings. They also performed over 400 safe work observations and spent over 450 hours responding to employee safety questions;
- Three FTEs deliver courses, on-the-job training and mentoring to approximately 300 employees in the Distribution Design and Customer Connect KBU and 30 trainees; and
- Three FTEs manage the budget and program progression for approximately 200 apprentices and 20 Engineers-in-Training.

This department's non-labour budget primarily consists of travel costs for Safety Advocates and Trades Training Instructors.

5D.5.2.7. Trainees Department

This department's budget is managed by the Technical and Trades Training department. The majority of this department's budget relates to labour costs for 250 FTEs who are apprentices and trainees, training for roles such as Power Line Technicians, Electricians, Mechanics, Utility Fleet Mechanics, Distribution Design and Customer Connect technologists, Communication Protection and Control technologists and Engineers. Approximately 77 per cent of their labour costs are charged out to other KBUs or specific projects and the remaining 23 per cent is charged to training.

This department's non-labour budget includes travel expenses and tuition to attend third party institutions (e.g., British Columbia Institute of Technology, Thompson Rivers University and the University of the Fraser Valley), relocation costs for trainees as well as small non-capital tools costs for new trainee and apprentice intakes.

This department's materials budget provides funding for their initial set of personal protection equipment.

5D.5.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5D-7 Learning and Development KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.4 L2	25.0	25.7	25.0	23.2	25.4	25.5	25.8	26.2
2	FTEs	16.0 L25	438	456	438	437	438	358	317	300

Operating costs are increasing by approximately $0.3 million from fiscal 2019 forecast to fiscal 2020 plan due to Standard Labour Rate increases which are partially offset by reduced training requirements and relocation savings due to a reduced number of apprentices and trainees. Operating costs are increasing by approximately $0.4 million from fiscal 2020 plan to fiscal 2021 plan due to Standard Labour Rate increases.

FTEs are planned to decrease during the test period, primarily due to a reduction in the planned number of apprentice and trainee intakes, which are based on future resourcing requirements.

5D.6 Field Safety Services KBU

5D.6.1 Responsibilities

The Field Safety Services KBU provides occupational safety and health expertise and support to BC Hydro's workforce and work programs, including work completed by contractors. The Field Safety Services KBU is dispersed across the province, and provides in-the-field safety expertise during all phases of work through reviewing safety plans, field inspections and spot audits, and delivering training in the field. Field Safety Services staff has the training expertise for confined spaces, fall protection, worksite coordination and hazardous materials, and are often geographically located at headquarters and field offices where training is required. The training delivered by the Field Safety Services KBU is coordinated with the Learning and Development KBU.

Since the Previous Application, the following changes have been made to the responsibilities of this KBU:

- The Aircraft Operations department has been transferred from the former Field & Grid Operations KBU to the Field Safety Services KBU;
- The Occupational Safety and Health (**OSH**) Specialists supporting Construction Services in the Learning and Development KBU have been transferred back to the Field Safety Services KBU;

- BC Hydro's Safety Advocates are now part of the Learning and Development KBU; and
- As a result of the implementation of the Safety Taskforce contractor safety recommendation to address inconsistencies in managing the safety of contractors, a Capital Safety Planning team was initiated in Field Safety Services.

The Safety System and Assurance and Learning and Development KBUs set direction through their regulatory expertise, safety engineering, safety initiative management and safety programs and standards. In turn, the Field Safety Services KBU functions as the "implementation arm" assisting other KBUs to apply safety standards, implement safety programs, and properly use approved safe work procedures as required by WorkSafeBC regulations (e.g., confined space safe work procedures).

Field Safety Services employs occupational safety and health professionals that support all BC Hydro functional areas and geographic locations, with a particular focus on KBUs performing hazardous work. Electrical safety services are provided to the field crews by the Safety Advocates and Trades Training Instructors in the Learning and Development KBU.

Field Safety Services includes OSH Specialists, Occupational Hygienists, and Aircraft Operations professionals and is organized into seven departments:

- Field Safety Services Manager Department;
- Field Safety Services Stations (Generation) Department;
- Field Safety Services Transmission and Distribution Department;
- Field Safety Services Construction Services Department;
- Field Safety Services Capital Project Delivery Department;

- Fleet, Materials Management, Properties and Office Safety Services Department; and
- Aircraft Operations Department.

While each of the Field Safety Services departments provides support to specific KBUs, their responsibilities are similar. These departments support any field work involving hazards such as asbestos, lead, silica, biohazards, confined space and working from heights. This support includes safe work planning and execution, conducting hazard identification, assessing risk, and developing safe work procedures (e.g., work in confined spaces or work involving hazardous substances, such as lead, silica, asbestos). During work execution, the departments observe job activities and conduct inspections, and provide coaching to field workers on regulatory compliance requirements and the correct use of health and safety equipment (e.g., atmospheric monitors, respirators, and rescue equipment). This coaching is provided so that safety regulations are followed and work is performed safely and in accordance with procedures.

BC Hydro’s capital occupational health and safety requirements are substantial, given the size of our capital program. The Field Safety Services KBU supports projects in the planning phase to achieve the appropriate contracting strategy, embeds safety requirements into contracts, develops required safety documentation (e.g., Owner Safety Plans, Owner Hazard Identification and Risk Assessments, and Safety Management Plans), and reviews contractor safety programs and safe work procedures. During construction, the Field Safety Services departments provide site safety coordination, inspect job sites and work activities and perform safe work observations (“formal verifications”).

To reduce risks associated with confined space entries, BC Hydro issued an internal safety directive, requiring an OSH Specialist ("Qualified Person" [252]) to attend every entry into a confined space, unless a Confined Space Supervisor has been specifically authorized to lead the work without an OSH Specialist present. BC Hydro has more than 15,800 confined spaces throughout its operations, and on average, there are 500 confined space entries per year.

Field Safety Services is also providing safety support to the Site C Project. Specific support was provided in fiscal 2019 through temporary assignments and shifting internal workloads, until additional resources were hired. The Field Safety Services KBU will continue to support the Site C Project safety efforts where required. This work is charged to the Site C Project.

The following is a list of the key role-specific responsibilities in the Field Safety Services KBU:

5D.6.1.1. OSH Specialists

The majority of the Field Safety Services KBU's field work mandate is performed by OSH Specialists who provide the following occupational safety and health services:

- Specialized support for field job planning, such as first aid assessments, job hazard identification and risk assessments, and the development of safety management plans and safe work procedures for hazardous materials, confined spaces, and fall protection hazards;
- Work execution support in the field, such as training delivery, safety coaching and mentoring, spot audits, and safe work observations;
- Contractor safety management, including providing safety expertise during the procurement phase when evaluating contracts, developing hazard

[252] Section 9.11 of the WorkSafeBC Confined Space regulations states that a "Qualified Person" must have adequate training and experience in the recognition, evaluation and control of confined space hazards, and must have specific qualifications, such as a certified industrial hygienist (CIH), or a Canadian registered safety professional (**CRSP**), or other combination of education, training and experience acceptable to WorkSafeBC.

identifications, risk assessments, and safety management plans during the planning phase and completing field verifications, during the construction phase;

- Assisting BC Hydro's KBUs in developing and implementing their annual safety plans; and
- Technical support for storm, fire and flood response (e.g., writing and overseeing safety management plans and first-aid assessments as well as fit-testing and providing instructions on how to use respiratory and other personal protection equipment).

5D.6.1.2. Occupational Hygienists

Occupational Hygienists are specialists with very specific qualifications who provide technical support and guidance to the OSH Specialists. These roles are field-focused and provide advice on the development of occupational hygiene policies, standards and programs. In particular, Occupational Hygienists develop and provide guidance on field safe work procedures for high hazard situations and unusual circumstances (e.g., procedures for complex asbestos abatement work).

5D.6.1.3. Management and Administrative Team

Safety Managers in the Field Safety Services KBU act as the single point of contact for KBUs throughout BC Hydro for all safety and health issues. Managers are also responsible for supporting the implementation of safety programs and initiatives.

The administrative team provides services such as expenses and purchasing management, contract administration, and communications support.

5D.6.1.4. Aircraft Operations Professionals

Aircraft Operations professionals within the Field Services KBU oversee all charter-related aviation activities including helicopter, fixed wing and remotely piloted aerial vehicle work. These professionals work in the Aircraft Operations department, which was created as a corrective action item following a 2008 incident that resulted in four fatalities. The department's functions include aviation related training requirements, policy development and adherence, risk assessment and mitigation, flight monitoring and internal flight coordination, as well as contract development and management. This oversight function applies to both BC Hydro and contractors' use of chartered aircraft for BC Hydro work. This level of oversight is necessary as Transport Canada only provides minimum oversight for utility charter aviation.

The Aircraft Operations manager liaises with all internal KBUs or departments that use aircraft services, provides strategic guidance and field support and conducts incident investigations. Aviation Safety Advisors verify the correct standard operating procedure, the correct aircraft for the flight, day-of-flight risk assessments, and source emergency aircraft as required.

5D.6.2 Overview of Operating Costs and FTEs

Table 5D-8 Field Safety Services KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Field Safety Services Manager	0.3	0.0	0.1	0.0	0.0	0.0	0.0	**0.4**	2
2	Field Safety Services Stations, Generation	0.9	0.0	0.1	0.0	0.0	0.0	0.0	**1.0**	9
3	Field Safety Services, T&D	1.6	0.0	0.2	0.0	0.0	0.0	0.0	**1.7**	15
4	Fields Safety Services Construction Svcs	0.2	0.0	0.0	0.0	0.0	0.0	0.0	**0.3**	4
5	Field Safety Svcs, Cap Project Delivery	0.9	0.0	0.1	0.0	0.0	0.0	0.0	**1.0**	20
6	Fleet, MM, Properties,Office Safety Svcs	0.8	0.0	0.0	0.0	0.0	0.0	0.0	**0.9**	8
7	Aircraft Operations	0.7	0.0	0.1	0.0	0.0	0.0	0.0	**0.9**	5
8	**Total (Sch 5.4 L3, Sch 16.0 L26)**	**5.5**	**0.0**	**0.6**	**0.1**	**0.0**	**0.0**	**0.0**	**6.2**	**63**

Overall, Field Safety Services provides support to:

- More than 2,100 BC Hydro field workers and front line managers;
- Work completion in more than 300 substations and 30 generating stations and over 86,000 km of transmission and distribution lines;
- All KBUs across BC Hydro, including office workers, to assist them in the development of their annual safety plans and addressing safety and health issues;

- BC Hydro's annual capital plan for construction and system upgrades; and
- Contractor safety management in all areas of the business.

The resourcing requirements for this KBU are driven by BC Hydro's ongoing capital and maintenance plan, safety programs and initiatives, as well as existing and changing WorkSafeBC requirements. In recent years, WorkSafeBC has provided increased scrutiny through dedicated high risk area inspection teams and higher financial penalties, especially for high hazard areas.

Benchmarking resourcing levels in Field Safety Services is challenging, because there are currently no Canadian Electrical Association benchmarks for the ratio of safety resources to utility workers. An approximate benchmark that can be applied to construction-type work is the informal construction industry ratio of between 1:50 and 1:75. Assuming that work performed by BC Hydro's Operations Business Group is comparable to construction type work, the ratio of OSH Specialists and Hygienists to front-line employees in the Operations Business Group at BC Hydro is 1:75 (28 to 2,100), which is consistent with this informal ratio. The overall ratio of Field Safety Services OSH Specialists and Hygienists to all BC Hydro employees is 1:150 (40 to 6,000).

5D.6.2.1. Field Safety Services, Manager Department

The majority of this department's budget consists of labour costs for two FTEs –the senior manager of the Field Safety Services KBU and an administrative assistant. The remaining budget is for contracted services and travel expenses.

5D.6.2.2. Field Safety Services, Stations (Generation) Department

The majority of this department's budget consists of labour costs for nine FTEs who provide support to employees in the Stations Field Operations KBU, with assistance from the Field Safety Services, Transmission and Distribution Department. These FTEs are deployed across the province, and are associated with the larger generation stations.

5D.6.2.3. Field Safety Services, Transmission and Distribution Department

The majority of this department's budget is related to labour costs for 15 FTEs who are dispersed across the province. Collectively, these FTEs provide support to employees in the Line Field Operations KBU and the Stations Field Operations KBU. In addition, the OSH Specialists in this department support an average of more than 500 confined space entries per year.

5D.6.2.4. Field Safety Services, Construction Services Department

This department's budget is largely related to labour costs for four FTEs who are located in the four Construction Services KBU headquarters across the province. The resourcing requirements in this department are driven by BC Hydro's capital plan and the occupational safety and health needs of BC Hydro's Construction Services KBU.

Between April and September 2018, these FTEs attended 531 crew interactions including 65 spot audits, 24 training events, 24 safety meetings, 99 confined space work occurrences, and 319 job planning and risk assessments as well as other crew support requests.

5D.6.2.5. Field Safety Services, Capital Project Delivery Department

This majority of this department's budget relates to labour costs for 20 FTEs. The FTEs in this department charge approximately 80 per cent of their time to the capital projects they support. The resourcing requirements in this department are driven by BC Hydro's capital plan. These 20 FTEs include 12 temporary OSH Specialists, allowing resources to be adjusted to match capital plan requirements.

Between April and September 2018, this department completed 353 formal contractor verifications and developed 22 Owner Safety Plans and 59 Owner Hazard Identifications and Risk Assessments. In addition, the department on-boarded 95 projects, and provided support to 592 projects under the Contractor Safety Management Program.

5D.6.2.6. Fleet, Materials Management, Properties and Office Safety Services Department

The majority of this department's budget consists of labour costs for eight FTEs. The remaining budget is for travel costs, primarily for the Hygienists, as they frequently travel across the province to provide specialized technical assistance.

5D.6.2.7. Field Safety Services, Aircraft Operations Department

The majority of this department's budget is for labour costs related to five FTEs.

The Aircraft Operations Department supports between 2,000 and 3,000 flight events per year. For example in fiscal 2018, the department provided oversight for 27 fixed wing charter flights, 1,778 helicopter charter flights, and 373 remotely piloted aerial vehicle flights.

5D.6.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5D-9 Field Safety Services KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.4 L3	4.9	5.7	5.0	5.7	5.1	6.2	6.6	6.7
2	FTEs	16.0 L26	53	50	55	56	55	63	62	62

Operating costs are increasing by approximately $0.4 million from fiscal 2019 forecast to fiscal 2020 plan and by approximately $0.1 million from fiscal 2020 plan to fiscal 2021 plan, primarily due to Standard Labour Rate increases.

FTEs are decreasing by one from the fiscal 2019 forecast to the fiscal 2020 plan, due to a reduction in planned overtime, and are planned to remain constant from the fiscal 2020 plan to the fiscal 2021 plan.

5D.7 Security and Emergency Management KBU

5D.7.1 Responsibilities

The Security and Emergency Management KBU safeguards our people, assets and operations from emergencies and disasters related to natural or human-induced events. The KBU reduces impacts to safety, reliability, reputation and finances by providing:

- Integrated physical security solutions, including the creation, management and sustainment of physical security controls required to meet NERC CIP regulatory compliance requirements;
- A structured process to identify critical business functions and processes through a company-wide business impact analysis and other business continuity processes; and
- The framework for company-wide emergency preparedness, including plans and procedures to help the organization respond to and recover from a major event.

This KBU also participates in the Canadian Electricity Association's Emergency Management and Security Councils. In addition, the KBU maintains mutual aid agreements with the Canadian Electricity Association and the Western Energy Institute, supporting disaster preparedness.

There have been no changes to the responsibilities of this KBU since the Previous Application.

The Security and Emergency Management KBU consists of the following departments:

- Security Investigations and Analytics Department;
- Emergency Management Department; and

- Security and Continuity Program Management Department.

The Security and Emergency Management KBU monitors evolving regulations and threats, and adapts to protect the Bulk Electric System and create a safe working environment for employees. The KBU also defines the standards for BC Hydro's physical security system and is responsible for its operation and maintenance. This includes establishing protective measures and procedures for regulatory compliance including Critical Infrastructure Protection, as set by the North American Electric Reliability Corporation.[253]

As an essential and critical service provider in British Columbia, BC Hydro has appropriate plans, training and exercises to be response-ready at a moment's notice. This KBU establishes and manages BC Hydro's framework to prepare for, respond to and recover from emergencies, aligning with the *Emergency Program Act*. BC Hydro has adopted British Columbia's Emergency Management Structure to improve response and recovery coordination and capabilities through standardization of roles, communication between organizations during a large response and a common understanding for response prioritization. This KBU develops the standards for response planning, conducts response training and exercising, and maintains necessary tools for immediate response such as situational awareness, earthquake and building damage assessment applications as well as emergency centres.

Since 2012, significant progress has been made in our Emergency Management Program, moving the program from underdeveloped to a mature state according to an external Disaster Preparedness Audit. [254] BC Hydro is also experiencing more extreme seasonal weather events including flooding, wildfires and winter storms, which require improved capacity and capability to recover quickly.

[253] The BCUC requires BC Hydro to comply with these Mandatory Reliability Standards.
[254] Further information on this audit is provided in Appendix HH.

5D.7.2 Overview of Operating Costs and FTEs

Table 5D-10 Security and Emergency Management KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Security Investigations and Analytics	1.2	0.0	5.2	0.0	0.0	0.0	0.0	**6.4**	8
2	Emergency Management	0.9	0.0	0.1	0.0	0.1	0.0	0.0	**1.0**	6
3	Security and Continuity Program Mgmt	1.3	0.0	0.2	0.0	0.0	0.0	0.0	**1.5**	8
4	Security and Emergency Mgmt	0.6	0.0	0.1	0.0	0.0	0.0	0.0	**0.7**	4
5	**Total (Sch 5.4 L4, Sch 16.0 L27)**	**4.0**	**0.0**	**5.5**	**0.1**	**0.1**	**0.0**	**0.0**	**9.6**	**26**

5D.7.2.1. Security Investigations and Analytics Department

This department’s labour budget is related to eight FTEs and its non-labour budget provides funding for BC Hydro’s external security contract.

Four FTEs manage BC Hydro’s physical security program, keeping our people and assets safe and secure. An external security contract provides security services including staffing a 24/7 security command centre, security guards, and security system technicians. Outsourced work includes guarding services as well as specialized technician work that is unpredictable and dispersed across the province. This allows BC Hydro to contract for specialized services at a lower cost and enables this department to act as a knowledgeable owner, with key responsibilities kept in-house such as regulatory compliance, standards, systems knowledge and engineering. This model is consistent with other comparable Canadian utilities and Crown Corporations.

BC Hydro’s current security contractor was selected in 2012 through a competitive bid process. The contract provides security services at more than 150 facilities and 45 substations across the province and includes installation and service of more than 2,200 cameras, 4,300 intrusion points and 2,400 access card readers, enabling prompt detection of a security anomaly and rapid determination of the threat level and appropriate response. In fiscal 2018, the department deployed over 134,000 hours of permanent guards (greater than 12 months at a post) and approximately 20,000 hours of temporary guards (less than 12 months at a post).

The Security and Emergency Management KBU has developed a Category Strategy and is partnering with Supply Chain's Procurement Team to fulfill the Strategy, leveraging their procurement expertise. A competitive bid will be prepared in fiscal 2019 to address our evolving security needs within today's market. New contract(s) will be established to deliver cost-effective security services, starting in fiscal 2020. The demands on the security program are changing, primarily driven by regulatory compliance requirements. In addition, threats are changing and becoming more sophisticated. The use of technology will increase going forward, as it is often a more reliable and cost-effective security solution.

The other four FTEs in this department provide security analytics and investigations. Work in this area is increasing in complexity. This team has been successful at reducing break and enters and thefts as well as at increasing arrests. This can be attributed to an integrated security program including the use of technology, human response and intervention. Table 5D-11 below shows the number of incidents, our investigations[255] and the number of arrests from fiscal 2017 to fiscal 2019.

Table 5D-11 Incidents, Investigations and Arrests (Fiscal 2017 to Fiscal 2019)

	Incidents (Excluding Frauds)	Incidents Assigned to an Investigator	Break and Enters or Thefts	Arrests
Fiscal 2017	1505	333	341	9
Fiscal 2018	1719	366	319	12
Fiscal 2019 (up to December 31, 2018)	1773	315	259	20

These FTEs also perform threat assessments. From April 2018 to December 2018, the team conducted 117 unplanned assessments. Sixty-five of these assessments were performed to assess security risks on capital projects and deploy appropriate security controls (e.g., temporary security guards, fencing, video surveillance, and/ or access detection to mitigate risks). Fifty two assessments were conducted to

[255] Incidents include such things as break and enter, theft, vandalism, public / customer threat, assistance to police or external agency, mischief and trespassing.

support employees traveling internationally for work. Assessments for international travel involve a risk assessment and follow-up with the traveller(s) including an information package and briefing to provide tips on how to stay safe.

FTEs on this team typically have experience in policing or military and generally hold certifications with the American Society for Industrial Security International, including designations such as Certified Protection Professional, Associate Protection Professional, Physical Security Professional or Professional Certified Investigator.

5D.7.2.2. Emergency Management Department

The majority of this department's budget relates to labour costs for six FTEs who build, maintain and operate BC Hydro's emergency management program, which provides a systematic and coordinated response to emergencies and disasters.

This department sets standards, establishes processes, and works with KBUs to help develop and maintain their site specific plans. The department maintains over 200 plans[256] including approximately 125 regulatory plans, requiring an annual review. The department also supports public safety and preparedness, liaising with external agencies such as Emergency Management British Columbia, critical infrastructure owners, government agencies, police, stakeholders and First Nation communities. An example of this work is our 14 emergency planning guides[257] which are shared externally and provide key information on BC Hydro's dams including inundation maps, contacts, and emergency and communication procedures.

The Emergency Management department also provides specific training on the roles required for emergency preparedness and response and conducts annual exercises to test processes and provide learning opportunities for employees working within our emergency management system during an event. From April 2018 to

[256] Plans include such things as facility emergency plans, plans for Dams and Stations, building damage assessment, and supporting plans such as emergency centre plans, wildfire, tsunami, flood, and storm response.

[257] Requirement of the Water Sustainment Act, Dam Safety Regulation and are also issued annually to the Water Comptroller. An emergency planning guide may include numerous dams based on river system. For example, Campbell River emergency planning guides has all dams on Campbell River System.

December 2018, 129 employees were trained in their response roles and 114 exercises were completed.

In addition, this department maintains all BC Hydro emergency centres (two corporate emergency coordination centres and six regional emergency operation centers) in a state of readiness and regularly reviews and updates standard operating procedures, including testing associated equipment. The department also coordinates mutual aid with our partners across Canada and the Western Grid.

During an emergency event, the department activates our emergency management structure which may include emergency centre(s). The department also provides leadership and subject matter expertise for company-wide prioritization, internal and external coordination and situational awareness during an emergency. Table 5D-12 below shows BC Hydro's emergency management plans, exercises and significant emergency centre activations from fiscal 2017 to fiscal 2019.

Table 5D-12 BC Hydro Emergency Management Plans, Exercises and Emergency Centre Activations

	Plans	Exercises		Emergency Centre Activations
		Evacuation drills	EM Exercises	
Fiscal 2017	143	126	2	22
Fiscal 2018	129	115	2	9
Fiscal 2019 (up to December 31, 2018)	117	112	3	8

A key component to the Emergency Management program is continual improvement. This department compiles a report following each exercise or incident which identifies corrective actions to improve plans and procedures. The team collaborates with the Safety Investigations team when incidents involve safety or more complex issues.

5D.7.2.3. Security and Continuity Program Management Department

The majority of this department's budget relates to labour costs for eight FTEs.

Six FTEs design and oversee the build and maintenance of BC Hydro's integrated physical security system, which is evolving due to emerging threats and new regulations. Security engineers set security standards and establish procedures while maintaining day to day operational compliance with the NERC CIP regulatory requirements. For example, the department developed and maintains BC Hydro's Master Physical Security Plan, developed and implemented physical access procedures, managed the installation of electronic key cabinets at 12 sites and conducted the re-keying of over 600 doors and cabinets at nearly 60 facilities across the province. The team provides ongoing compliance support for NERC physical security sustainment activities, including physical access monitoring, training and engagement with the Operations Business Group, as well as evidence collection and submission.

Two FTEs are accountable for the company's business continuity program. This includes establishing the standard and processes to maintain the company's Business Impact Analysis as well as developing and exercising continuity plans and supporting continual improvements. In fiscal 2018, 34 Business Impact Analyses were completed, identifying our critical technology and applications, people, work space and third party suppliers. KBUs use the results of the Business Impact Analysis to develop mitigation strategies which maintain critical operations during an emergency or restore services as quickly as possible.

5D.7.2.4. Security and Emergency Management Department

The majority of this department's budget relates to labour costs for four FTEs including the Manager of Security and Emergency Management and an administrative assistant. The remaining two FTEs oversee and prioritize key projects[258] as well as monitor and report overall program metrics.

[258] Examples include NERC implementation and sustainment for physical security, NERC's Grid Security Exercise, security standards and application guide development and Category Management for Security Services.

5D.7.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5D-13 Security and Emergency Management KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.4 L4	9.3	9.4	9.3	9.2	9.3	9.6	10.7	10.8
2	FTEs	16.0 L27	18	20	18	25	18	26	31	31

Operating costs are increasing by approximately $1.1 million from fiscal 2019 forecast to fiscal 2020 plan, due to:

- The transfer of positions for security requirements for BC Hydro's NERC CIPv5 physical security program (discussed further in Chapter 5C, section 5C.10.3);
- An increase in forecast costs for BC Hydro's security contract of $0.2 million; and
- Standard Labour Rate increases.

Operating costs are increasing by approximately $0.1 million from fiscal 2020 plan to fiscal 2021 plan due to Standard Labour Rate increases.

FTEs are planned to increase by five from fiscal 2019 forecast to fiscal 2020 plan due to the transfer of positions for NERC CIPv5 (discussed further in Chapter 5C, section 5C.10.3). FTEs are planned to remain constant from fiscal 2020 plan to fiscal 2021 plan.

5D.8 Business Unit Support KBU

5D.8.1 Responsibilities

The Safety Business Unit Support KBU holds the budget for the Office of the Senior Vice-President of Safety.

5D.8.2 Overview of Operating Costs and FTEs

Table 5D-14 Business Unit Support KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	SVP, Safety and Learning	0.5	0.0	0.1	0.0	0.0	0.0	0.0	**0.6**	2
2	**Total (Sch 5.4 L5, Sch 16.0 L28)**	**0.5**	**0.0**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.6**	**2**

5D.8.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5D-15 Business Unit Support KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.4 L5	0.5	0.6	0.5	0.6	0.5	0.6	0.6	0.6
2	FTEs	16.0 L28	2	2	2	2	2	2	2	2

Operating costs are planned to remain relatively constant from fiscal 2019 forecast to fiscal 2020 plan and fiscal 2021 plan.

BC Hydro
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Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Chapter 5E

Operating Costs
Finance, Technology, Supply Chain Business Group

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5E.1 Introduction – Finance, Technology, Supply Chain Business Group

Chapter 5E provides and explains in detail the composition of, and rationale for, the operating costs of the Finance, Technology, Supply Chain Business Group. The Finance, Technology, Supply Chain Business Group is one of six business groups in the organization and serves a Support function of the Plan-Build-Operate-Support model.

The Finance, Technology, Supply Chain Business Group budget was developed as part of the budgeting process outlined in Chapter 5, section 5.4. The information provided in this Chapter 5E demonstrates the basis for the entirety of the Business Group and KBU budgets, rather than focussing only on incremental cost requirements.

Chapter 5E is organized as follows:

- Section 5E.2 provides an overview of the organization and responsibilities of the Finance, Technology, Supply Chain Business Group;
- Section 5E.3 provides the operating costs and FTE information for the Finance, Technology, Supply Chain Business Group as a whole[259];
- Sections 5E.4 to 5E.7 provide more detailed information on the responsibilities, cost and FTEs for each KBU within the Finance, Technology, Supply Chain Business Group. The operating costs and FTE information for each KBU is broken out into two sections:[259]
  - Overview of Operating Costs and FTEs – This section explains the starting operating costs and FTEs based on the fiscal 2019 forecast; and

[259] Please note the amounts presented in the tables in these sections may not add due to rounding.

- Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs – This section explains any incremental changes between the fiscal 2019 forecast and the fiscal 2020 and fiscal 2021 plan.

5E.2 Overview of Finance, Technology, Supply Chain Business Group Organization and Responsibilities

The Finance, Technology, Supply Chain Business Group's responsibilities include:

- Providing corporate-wide financial services and support to BC Hydro's KBUs and overseeing financial decisions consistent with BC Hydro's policies and controls. This includes budgeting, planning, forecasting, accounting, financial reporting, tax compliance and planning, cash management, debt and foreign exchange management, risk management, performance improvements through the Work Smart program, internal audit, and overseeing financial policy compliance;
- Facilitating the delivery of materials, vehicles and procurement services necessary for BC Hydro to provide service to customers; and
- Selecting, implementing and operating technology across BC Hydro. This includes managing information technology and operational technology systems to meet compliance and security requirements, sustain productivity, manage risks and enable business objectives.

The Finance, Technology, Supply Chain Business Group consists of the following KBUs:

Business Group	Key Business Unit
Finance, Technology, Supply Chain	Finance Technology Supply Chain Business Unit Support

The following material changes have been made to the responsibilities of the Finance, Technology, Supply Chain Business Group since the Previous Application:

- In fiscal 2017, the Technology KBU moved from the previous Transmission, Distribution and Customer Services Business Group to the Finance, Technology, Supply Chain Business Group;
- In fiscal 2018, the Business Planning and Risk department and the Change Management department moved from the previous Corporate Affairs KBU to the Finance KBU within the Finance, Technology, Supply Chain Business Group; and
- In fiscal 2018, the Smart Metering and Network Operations department moved from the former Smart Technology Operations and Restoration KBU to the Technology KBU within the Finance, Technology, Supply Chain Business Group.

These changes were cost neutral and did not increase the total number of FTEs.

5E.3 Fiscal 2020 and Fiscal 2021 Plan Operating Cost and FTE Summaries

This section addresses planned operating costs and FTEs for the Finance, Technology, Supply Chain Business Group. The following are some key points of note with respect to the information provided in Figure 5E-1, Table 5E-1 and Figure 5E-2, Table 5E-2 and Table 5E-3.

- The Finance, Technology and Supply Chain business group's operating cost budget varies significantly between each KBU.
- The Technology KBU accounts for 51 per cent, or $135.8 million, of the total operating cost budget for the Finance, Technology and Supply Chain business group. All cross organizational technology costs are managed on a consolidated basis within the Technology group, such as licenses, maintenance fees, data center and end point devices.
- The Supply Chain KBU accounts for nearly 50 per cent, or 454 FTEs, of total FTEs for the Finance, Technology and Supply Chain business group. This is

primarily to deliver fleet and materials management services, which account for nearly 300 FTEs, where a regional presence is required to support front line operations.

- From fiscal 2019 RRA to Fiscal 2021 Plan, the increases in the Finance, Technology and Supply Chain KBU operating budgets are largely driven by Standard Labour Rate increases, partially offset by vacancy factor savings.

Planned operating costs for this Business Group are approximately $262.6 million in fiscal 2020 and approximately $264.8 million in fiscal 2021. The operating costs for the Finance, Technology, Supply Chain Business Group are summarized by KBU in Figure 5E-1. Additional cost details are provided in Table 5E-1 below.

Figure 5E-1 Finance, Technology, Supply Chain Net Operating Costs by KBU (Fiscal 2020 Plan) ($ million)

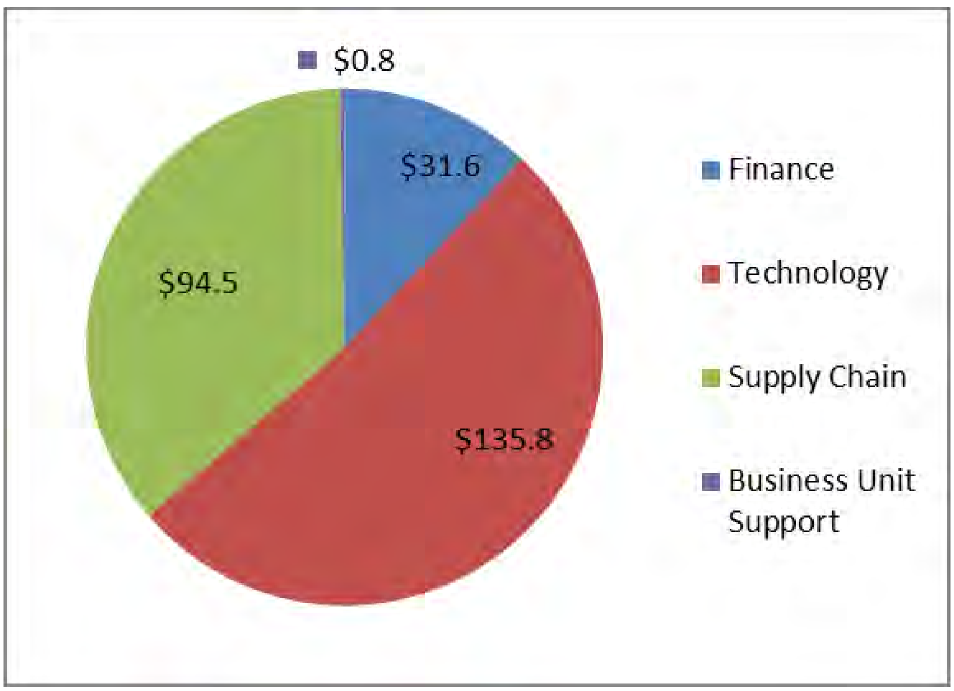

Table 5E-1 Finance, Technology, Supply Chain Net Operating Costs by KBU

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Finance	5.5 L1	29.7	28.7	30.2	28.7	30.7	30.8	31.6	32.1
2	Technology	5.5 L2	141.1	134.5	141.3	128.3	140.5	133.7	135.8	136.4
3	Supply Chain	5.5 L3	91.8	89.9	92.2	89.0	93.0	93.3	94.5	95.5
4	Business Unit Support	5.5 L4	0.8	0.7	0.8	0.7	0.8	0.8	0.8	0.8
5	Total	5.5 L11	263.3	253.8	264.4	246.7	265.0	258.5	262.6	264.8

The FTEs for the Finance, Technology, Supply Chain Business Group are summarized by KBU in Figure 5E-2. Additional details are provided in Table 5E-2 below.

Figure 5E-2 Finance, Technology, Supply Chain FTEs by KBU (Fiscal 2020 Plan)

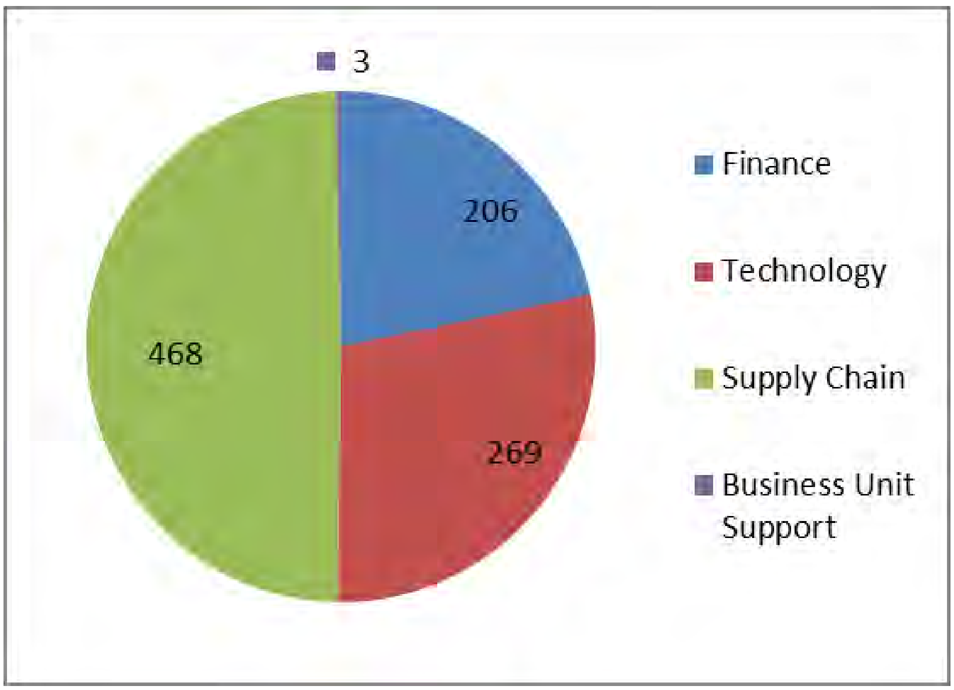

Table 5E-2 Finance, Technology, Supply Chain FTEs by KBU

	(FTEs)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Finance	16.0 L30	188	194	188	196	188	204	206	206
2	Technology	16.0 L31	176	186	191	226	202	263	269	269
3	Supply Chain	16.0 L32	402	421	402	447	402	454	468	468
4	Business Unit Support	16.0 L33	3	3	3	3	3	3	3	3
5	Total	16.0 L34	769	805	784	871	795	924	946	946

Table 5E-3 below provides a continuity table which highlights changes to the Finance, Technology, Supply Chain Business Group from the Previous Application. An overall discussion of these changes, at a company-wide level, is provided in Chapter 5, section 5.5.2. Further details, by KBU, are provided in the sections below.

Table 5E-3 Finance, Technology, Supply Chain Operating Costs Continuity Schedule

	($ million)		F2020 Plan	F2021 Plan
1	F2019 Revenue Requirement Application Plan		-	
2	Reorganization Impacts		265.0	
3	F2019 Revenue Requirement Application Plan (Finance Technology Supply Chain)		265.0	
4	Budget Transfers Between Business Groups		(6.5)	
5	Adjusted F2019 Revenue Requirement Application Forecast (Finance Technology Supply Chain) / carry forward plan (Schedule 5.5, line 11)	A	258.5	262.6
6	Current Year Budget Transfers Between Business Groups	B	0.2	0.5
7	Test Period Savings			
8	Vacancy factor savings		(1.4)	
9		C	(1.3)	-
10	Test Period Cost Increases			
11	Labour		5.3	1.6
12		D	5.3	1.6
13	Test Period Net Increase/(Decrease)	E=C+D	4.0	1.6
14	Net Operating Costs (Schedule 5.5, line 11)	A+B+E	262.6	264.8

5E.4 Finance

5E.4.1 Responsibilities

The Finance KBU provides corporate financial and treasury services, financial support to all of BC Hydro's KBUs, internal audit services, and oversight to financial decisions to ensure they are consistent with BC Hydro's policies and controls.

The Finance KBU performs an important role in the financial stewardship of BC Hydro. To effectively manage an organization as complex as BC Hydro, stakeholders across the company require accurate, timely and insightful financial and management information throughout the annual business cycle and in forward planning. The Finance KBU provides this information through a robust system of controls, as well as complementary services such as internal audit, change management, and Work Smart that add further value to the business and enable BC Hydro to deliver on our Service Plan commitments.

In fiscal 2014, the finance functions were consolidated under the Chief Financial Officer. This enabled the Finance KBU to function as a more effective, centralized organization. Through this centralization, BC Hydro was able to realize 11 net headcount reductions.

Since fiscal 2014 there has been increased demand for the services of the Finance KBU. BC Hydro's business environment continues to grow in complexity each year. Examples of the increased demand on the Finance KBU include the following:

- Increased FTEs across BC Hydro requiring support from the Finance KBU;
- Increased capital expenditures which have contributed to, among other things, an approximately 40 per cent increase in the volume of project due diligence reviews, conducted by the Finance KBU since fiscal 2016; and
- Increased internal and external reporting requirements, both internally and externally, to meet project, policy and regulatory requirements and to ensure our projects have the appropriate oversight to remain on time and on budget. For example, with increased levels of capital expenditures, BC Hydro has developed enhanced reporting for the Capital Delivery Management Committee to add more information on pre-construction and post-construction aspects of project expenditures, providing further visibility to the lifecycle costs of the capital plan.

Despite the above factors, the size and budget of the Finance KBU has remained relatively constant. The increased workload of the Finance KBU is illustrated by the ratio of finance business support FTEs, who provide day-to-day support to all of BC Hydro's KBUs, to BC Hydro's total FTEs. Today, each of the 77 Finance FTEs in the Finance Business Support department who provide day-to-day support to all of BC Hydro's KBUs support an average of 84 FTEs across the company. In fiscal 2014, that same number of Finance FTEs would have been supporting an average of 72 FTEs.

In addition to meeting increased demands and workload while maintaining a relatively constant size and budget, the Finance KBU has led and contributed to many additional initiatives, including:

- Planning – Finance coordinates the completion of annual business plans for each KBU, and creates the annual focus document, which provides clarity and alignment on BC Hydro's priorities across the company;
- Reporting – Finance produces 32 dashboards per month on key performance indicators and targets critical to achieving business objectives that are used across the company to manage business performance;
- Debt Management – the Treasury team now manages approximately $23 billion in total debt and $8 billion in derivative financial instruments, including those related to hedging under our debt management strategy to achieve increased cost certainty for ratepayers on long-term borrowings;
- Forecasting – Finance has led the ongoing efforts to manage within the former 2013 10 Year Rates Plan, including identifying and implementing actions to stay on track, and formulated the updated rates forecast released in the Comprehensive Review; and
- Work Smart – Work Smart is a key enabler in limiting our operating cost increases. We estimate that initiatives led by Work Smart, leveraging the collaboration of teams across BC Hydro have resulted in over 80,000 annual capacity hours gained. This enables the equivalent of over 50 FTEs' worth of effort to address increasing workload and to focus on higher-value work.

The responsibilities of the Finance KBU have changed since the Previous Application. The Business Planning and Risk department and the Change Management department, formerly part of the Corporate Affairs KBU, are now part of the Planning, Forecasting and Risk department of the Finance KBU.

The Finance KBU consists of the following departments:

- Finance Business Support Department;
- Controllership and Treasury Department;
- Planning, Forecasting and Risk Department; and
- Audit Services Department.

5E.4.1.1. Finance Business Support Department

This consolidated finance team is the internal, client-facing team that provides day-to-day and ongoing financial services and support to all of BC Hydro's KBUs, including:

- Facilitating business processes and initiatives through an understanding of the specific business needs of each department and assisting the business unit in achieving its goals from a financial perspective;
- Providing management consultation and decision support services to management teams, front line managers and staff. This includes financial evaluation, risk analysis, and recommendations on strategic issues, capital and initiative investment proposals, and day-to-day operational issues and decisions;
- Supporting business groups delivering capital projects by reviewing capital requests, providing input into the annual prioritization process, providing annual and long-term capital reporting and forecasting, converting projects into assets, preparing depreciation forecasts, completing due diligence reviews (e.g., financial reviews of business cases), preparing financial models, and preparing contract requisitions;
- Ensuring all employees are educated on and following corporate controls and policies;

- Facilitating the annual financial planning, work planning and resource allocation process at the KBU level;
- Applying BC Hydro's accounting and costing methodologies and systems to all financial transactions;
- Delivering management and cost accounting services to provide timely and accurate recording and reporting of cost information to support decision making;
- Providing budget support to the management teams of each KBU including reviewing overall budgets, cost pressures, cost savings and initiatives to develop a prioritized operating and capital budget;
- Preparing monthly reporting for business groups and individual KBUs including variance explanations, trends, emerging business issues and forecasts of year end results;
- Providing revenue and cost of energy reporting including variances, trends and forecasts;
- Preparing non-energy and miscellaneous billing reports and issuing invoices in compliance with contracts;
- Processing transactions including preparing and posting journal entries and completing general ledger reconciliations; and
- Completing accounting reviews including reviews of expenditures among supported KBUs, and working with the financial reporting team in the Controllership and Treasury Department to determine the appropriate accounting treatment.

5E.4.1.2. Controllership and Treasury Department

The Controllership and Treasury department consists of six teams that provide financial management and oversight at BC Hydro. A significant portion of this work supports BC Hydro's statutory reporting requirements to our shareholder and the BCUC. This department includes the following teams:

- **Treasury:** this team is responsible for cash and foreign exchange management and banking, debt management, insurance management, credit risk management and pension plan management. This involves ensuring that BC Hydro has sufficient financial resources to fund its operations and capital plan, maintaining credit facilities and developing and implementing debt management strategies. Treasury is also responsible for managing finance charges, procuring and managing operational and construction insurance programs, and evaluating, monitoring and reporting credit exposures. Treasury also manages investments associated with BC Hydro's pension plan and non-pension post-retirement benefits;
- **Financial Reporting:** this team is responsible for preparing and presenting BC Hydro's consolidated internal and external financial reports. The team manages the external financial statement audit and review process, leads the planning, assessment and implementation of new and revised IFRS standards and provides accounting policy guidance, interpretations and assessments for complex accounting issues;
- **Internal Controls and Policy:** this team is responsible for maintaining and overseeing compliance with internal financial controls by ensuring financial policies are developed and updated, reviewing instances of control exceptions, providing business support for technology solutions, preparing and reviewing financial system access requests, and creating risk and control assessments for projects and initiatives across BC Hydro to support successful business outcomes;
- **Financial Processes:** this team is the conduit between Finance and Technology to ensure that our financial systems are configured to meet business requirements, are operating as designed, and are delivering data in a

timely manner. This team also provides technical support to users and develops solutions to enhance the financial systems to meet reporting requirements;

- **Financial Accounting and Compliance:** this team provides back-office support for the Treasury group and is directly responsible for the accounting, forecasting, and financial analysis of information pertaining to debt, derivatives, pension and other post-employment benefits; and
- **Taxation:** this team provides tax planning and advice throughout the company on property sales and purchases, procurement activities, sales transactions and employee benefits. The team also prepares and submits all the sales and income tax returns for the business and handles dispute resolution with suppliers, customers and tax authorities.

5E.4.1.3. Planning, Forecasting and Risk Department

The Planning, Forecasting and Risk department consists of five teams that deliver the following services which drive decision making, focus and productivity throughout the organization:

- **Business Planning:** this team leads the corporate-wide annual business planning and budgeting process, as well as the development of performance metrics and performance tracking related to business plans for each of BC Hydro's KBUs. The annual planning process involves the development of business plans and the annual focus document, which outlines the key priorities across BC Hydro and within the Business Groups. These business plans provide clarity on our priority work and help to measure progress towards achieving our objectives throughout the year. The annual focus document provides clarity to employees on the company-wide and Business Group objectives and key priorities and ensures alignment of work activities across the company. Dashboards and scorecards prepared by this team are a key performance tool to track progress on targets and help managers identify areas of concern and implement corrective action, if required, to bring performance back on track. The annual financial budgeting/planning process at the overall company level is led by this team in coordination with the Finance Business Support department, which facilitates the process at the KBU level. BC Hydro's budgeting process is described further in Chapter 5, section 5.4;

- **Enterprise Risk Management:** this team leads BC Hydro's approach to enterprise risk, including the annual refresh of the risk landscape, and ongoing monitoring and reporting of key risks and emerging risks to the Executive and Board of Directors. This team also works with Business Groups and KBUs throughout BC Hydro during the annual planning process to identify and understand key risks related to achieving business objectives so that these risks are considered in the development of each KBU's business plan as well as actively monitored throughout the fiscal year;
- **Forecasting:** this team is responsible for preparing and updating BC Hydro's consolidated financial forecast, which is part of BC Hydro's internal and external reporting requirements, and informs BC Hydro's Revenue Requirements Applications and annual Service Plan. The forecast is used extensively by management in making both short-term and long-term financial decisions. In addition to regular forecast updates, this team is also involved in key initiatives and regulatory filings. Previous examples include the Site C Inquiry, the 2017 Waneta Transaction Application, the Supply Chain Applications Project Application, and the Government of B.C.'s Comprehensive Review;
- **Work Smart:** this team leads BC Hydro's performance improvement initiatives through the Work Smart program. Further information on the Work Smart program is provided in Chapter 5, section 5.4.5; and
- **Change Management:** this team works on projects and initiatives across BC Hydro to understand what people need to do differently to achieve the benefits of the project. Communications, engagement, training and leadership plans are developed for specific groups so that that they have the appropriate

knowledge, skills and abilities to perform their roles - both during and after the change. They also play a key role in ensuring leadership support and business ownership for the change to drive long term sustainment and achievement of benefits. This is a critical component to all projects where employee productivity is involved.

5E.4.1.4. Audit Services Department

The purpose of Audit Services is to provide independent, objective assurance and consulting services to add value and improve BC Hydro's operations. Audit Services reports functionally to the Audit and Finance Committee of the BC Hydro's Board of Directors and administratively to the Executive Vice President of Finance, Technology and Supply Chain and Chief Financial Officer.

Audit Services adheres to the Institute of Internal Auditors International Standards for the Professional Practice of Internal Auditing.

The Audit Services department develops and executes a two-year Audit Plan which incorporates both operational and financial audits to address BC Hydro's key risks and priorities. Information on the types and outcomes of the audits undertaken over the last three fiscal years can be found in Appendix HH.

5E.4.2 Overview of Operating Costs and FTEs

Table 5E-4 Finance KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Finance Business Support	16.6	0.0	0.4	0.1	0.0	0.0	0.0	**17.2**	121
2	Controllership and Treasury	5.4	0.0	0.9	0.0	0.1	0.0	0.0	**6.4**	35
3	Planning, Forecasting and Risk	5.0	0.0	0.2	0.0	0.0	0.0	0.0	**5.3**	36
4	Audit Services	1.5	0.0	0.3	0.0	0.0	0.0	0.0	**1.9**	12
5	**Total (Sch 5.5 L1, Sch 16.0 L30)**	**28.6**	**0.0**	**1.9**	**0.1**	**0.2**	**0.0**	**0.0**	**30.8**	**204**

The Financial Executives Research Foundation, together with Robert Half, published a report entitled 2018 Benchmarking Accounting and Finance Functions. The report includes analyses of the number of internal staff and the cost of staff for finance and accounting functions for companies of various sizes in North America.

The analyses provided data for companies of different sizes, based on annual revenues.

The following table compares BC Hydro's FTEs and base operating cost budget to the benchmarks provided in this report for both revenue categories.

Table 5E-5 Benchmarking Accounting and Finance Functions

Benchmark	BC Hydro	Companies with annual revenue of $5 billion and higher
Number of internal staff in Accounting and Finance	181[260]	180 (median)
Cost of internal staff in Accounting and Finance as a percentage of overall revenues	0.49%[261]	0.5% (bottom quartile) 0.8 (median)

As shown in the table above, the Finance KBU's FTE complement is comparable to the median for companies with revenues of $5 billion and higher and is below the bottom (best) quartile of companies.

5E.4.2.1. Finance Business Support Department

Approximately 97 per cent of this department's budget is related to labour. This represents 121 FTEs as follows:

- Two Finance Directors and two administrative assistants;
- 77 FTEs supporting all of the KBUs within BC Hydro. Each of these finance FTEs supports an average of 84 FTEs and $15 million in annual operating budgets;

[260] The Finance KBU has 204 FTEs. However, this total includes 23 FTEs that perform business planning, change management and enterprise risk management functions which are not traditional finance and accounting functions. Excluding these FTEs, the total number of FTEs in the Finance KBU is 181.

[261] The Finance KBU has a base operating cost budget of $30.8 million which equates to approximately 0.49 per cent of BC Hydro's total fiscal 2018 revenues of $6.237 billion.

- 22 FTEs provide project reviews, evaluations, monitoring and reporting on over 500 capital projects or $1.6 billion in expenditures annually; analyse and convert over 2,500 projects and work orders into in-service assets; review 40 contracts and contract revisions for senior management and maintain asset records for $29 billion in capital assets;
- 11 FTEs are responsible for the annual preparation of 33,000 non-energy bills, processing of 6,000 journal entries and reconciliation of 150 general ledger accounts; and
- Seven FTEs provide monitoring and reporting services on BC Hydro's revenues and cost of energy. These FTEs handle the payment, accounting, forecasting, and budgeting for approximately 130 Electricity Purchase Agreements.

This Finance Business Support department has $0.5 million in non-labour expenditures (e.g., training, travel costs and professional dues and fees).

5E.4.2.2. Controllership and Treasury Department

Approximately 85 per cent of this department's budget is related to labour. This represents 35 FTEs as follows:

- Seven FTEs on the Financial Reporting team prepare over 80 internal and external financial reports and documents including monthly financial statements. In addition, this team is responsible for researching, analyzing, and drafting over 50 technical accounting memos relating to new accounting standards or supporting key initiatives and transactions across BC Hydro;
- Nine FTEs on the Treasury team. This team manages $23 billion in total debt, $8 billion in derivative financial instruments, over $20 billion in annual cash flow management, $70 million in average monthly accounts receivable through credit risk management, $1.4 billion in letter of credit facilities, a $4.6 billion insurance portfolio, and a $3.5 billion pension plan. The activities in this department are supported by the Financial Accounting and Compliance team;

- Five FTEs in the Financial Accounting and Compliance team provide back-office support for the Treasury team including accounting, forecasting, reporting and financial analysis of information pertaining to financial instruments, pension and other post-employment benefit plans, and finance charges. The team also monitors and reports monthly on the Treasury department's compliance with the Liability Risk Management Annual Strategic Plan and the Treasury Risk Management Policy. Best practices require the segregation of duties to an independent team to ensure that proper internal controls are in place for the safeguarding of assets and the accurate and timely recording of Treasury initiated transactions;
- 11 FTEs on the Internal Controls & Financial Processes teams maintain over 900 financial policy, procedure, and guideline documents, review business and travel expense compliance across BC Hydro on a quarterly basis, maintain approximately 35 Financial Process flow diagrams and review approximately 50 Technology projects each year. This team uses a risk and control framework to guide the design of financial controls, triage and support over 260 technical issues per year, initiate an average of 12 financial system and reporting enhancements per year, and conduct testing of system upgrades; and
- Three FTEs in Taxation.

Controllership and Treasury has $0.9 million in non-labour expenditures mainly for external audit, credit rating agency fees, and professional fees.

5E.4.2.3. Planning, Forecasting and Risk Department

Approximately 95 per cent of this department's budget is related to labour. This represents 36 FTEs as follows:

- 10 FTEs on the Business Planning and Risk team support the development of annual business plans for each of BC Hydro's key business units. These FTEs also carry out interviews and workshops to support BC Hydro's risk management activities and produce 32 dashboards per month on key performance indicators and targets critical to achieving business objectives;

- Nine FTEs on the Forecasting team support the preparation of the quarterly forecast update to the government and BC Hydro Board. This team is also critical in supporting key initiatives such as the Site C Inquiry, the BC Hydro 2017 Waneta Transaction and the Comprehensive Review;
- Four FTEs on the Work Smart team, which completes approximately 35 projects annually and has generated an estimated 80,000 annual capacity hours gained since the program's inception; and
- 13 FTEs on the Enterprise Change Management team which supports approximately 50 change management projects per year.

This Planning, Forecasting and Risk group has $0.2 million in non-labour expenditures (e.g., consultants, training, and professional dues and fees).

5E.4.2.4. Audit Services Department

Approximately 80 per cent of the Audit Services department budget is related to labour. This represents 12 FTEs who complete approximately 15 audits per year and follow up on past audits to ensure recommendations are being addressed. This team is also responsible for investigating claimed control breaches that are reported via the company's hotline. A description of the audits undertaken over the past three years can be found in Appendix HH.

The department's services budget primarily provides funding for external subject matter experts, which supplement our teams where subject-matter specific expertise can add value, such as dam safety, smart meter reviews and cybersecurity.

5E.4.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5E-6 Finance KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.5 L1	29.7	28.7	30.2	28.7	30.7	30.8	31.6	32.1
2	FTEs	16.0 L30	188	194	188	196	188	204	206	206

Operating costs are increasing by approximately $0.8 million from the fiscal 2019 forecast to the fiscal 2020 plan due to Standard Labour Rate increases. Operating costs are increasing by approximately $0.5 million from the fiscal 2020 plan to the fiscal 2021 plan due to Standard Labour Rate increases. FTEs are planned to remain stable.

The increase in FTEs from the fiscal 2019 RRA to the fiscal 2019 forecast was primarily driven by the Workforce Optimization program, described in Chapter 5, section 5.6.1.

5E.5 Technology KBU

5E.5.1 Responsibilities

The goal of the Technology KBU is to select, implement and operate technology across BC Hydro so that our systems are reliable, secure, and able to meet the information and operational needs of BC Hydro.

Technology plays an important role in BC Hydro, helping to deliver safe, reliable and affordable service to our customers. For example, the Technology KBU:

- Maintains the health, stability and security of our digital systems, helping to provide reliable and responsive electricity service;
- Enables productivity improvements through technology that streamlines workflows, optimizes work and asset management, and informs decision making; and

- Provides mobile applications with information specific to the job and location, which improves the safety of our field workers.

Since fiscal 2016, BC Hydro has made a number of changes to the management of the Technology KBU:

- **Reorganization:** Planning and performance functions were brought together into a single department to provide integrated and comprehensive investment planning;
- **Improved Technology Delivery Model:** The Technology KBU delivers services with both external and internal resources, using a multi-vendor outsourcing model. Since fiscal 2016, to improve service governance and vendor integration management, BC Hydro has:
  - Renegotiated application service support contracts to improve cost effectiveness and service, developed a Service Integration and Management capability to support service improvement opportunities across all vendors;
  - Replaced our Information Technology Service Management Tool with an internal system to eliminate dependence on external service providers and enable future flexibility; and
  - Created an internal cyber security monitoring and response capability to bring this critical service in-house and provide appropriate management of cyber security risks.
- **Repatriated Critical Roles under the Workforce Optimization Program:** As part of the Workforce Optimization Program, BC Hydro identified specific areas where contractors could be converted to internal employees to strengthen our team and repatriate critical roles. These areas included service governance, vendor integration management, cybersecurity, application services and project management. Overall, these conversions were cost neutral and were

undertaken so that critical functions were maintained in-house and to reduce the risk of losing institutional knowledge and the number of management roles being performed by contractors was reduced. Since fiscal 2016, the Technology KBU has converted 88 contractor positions to internal FTE positions; and

- **Created a New Technology Business Management team:** The Technology Business Management team was created to consolidate the governance functions from across Technology. This consolidation enables greater oversight and consistency in functions such as budget management, vendor management, contract management, policies and standards management, workforce planning, risk management, and records and information management.

Results on performance metrics tracked by the Technology KBU indicate that these changes have been successful. For example:

- **Operational Metrics:** Technology performs well against operational targets used to evaluate and track the performance of our systems and services. For example, from April 2018 to December 2018, BC Hydro had only two high business impacts technology incidents, well below the target level of nine or less. In addition, during the same period, only 8 per cent of calls to the Technology Help Desk waited longer than 30 seconds, below our target of up to 10 per cent. In addition, only 0.6 per cent of customer survey responses were dissatisfied with help desk service;
- **Delivery Metrics:** Technology performs well against metrics used to assess and track the performance of capital investment delivery which include measures on cost, schedule, and quality. Please refer to Chapter 6, section 6.5 for more information on Technology's delivery metrics; and
- **Business Satisfaction:** Technology recently started conducting an annual survey to solicit feedback from across the business to measure the level of satisfaction with Technology delivery and services. Results indicate that overall

satisfaction has improved over the three years of running the customer satisfaction survey.

There have been two material changes to the responsibilities of the Technology KBU since the Previous Application:

- The Telecommunications Planning department moved from the Technology KBU to the Line Asset Planning KBU; and
- The Smart Metering and Network Operations department moved from the former Smart Technology Operations and Restoration KBU to the Technology KBU.

Technology is comprised of the following departments:

- Business Partner Services Department;
- Planning and Performance Department;
- Delivery Department;
- Operations Department; and
- Smart Metering and Network Operations Department.

5E.5.1.1. Business Partner Services Department

The Business Partner Services department works directly with BC Hydro KBUs to understand their business needs and develop technology solutions. The department assists with developing statements of objectives and business cases, initiating work, and meeting business needs and objectives for all technology initiatives. The department also monitors issues, identifies and prioritizes enhancements, and oversees the delivery of sustainment programs for existing business systems and applications that are used by specific areas of the business. Enterprise-wide systems and applications are supported by the Operations department, which is described further below.

5E.5.1.2. Planning and Performance Department

The Planning and Performance department provides technology strategy development and investment planning, portfolio and resource management, cyber security governance, risk and compliance, and business management functions for the Technology KBU.

The investment planning teams are responsible for strategic planning of technology solutions across BC Hydro, integrated investment planning, and enterprise architecture, as well as infrastructure, network and cyber security investment planning. Enterprise architecture develops and maintains technology roadmaps, reference architectures and technical standards which are used to guide technology investment and design decisions.

The portfolio and resource management team manages the selection and prioritization of investments into the delivery portfolio, the availability of resources to deliver on investment plans, processes to track benefit realization from investments, monthly and quarterly tracking of the portfolio, as well as regulatory and long-term capital planning.

The cybersecurity governance, risk and compliance team provides risk assessments, training and awareness, as well as procedural oversight to maintain the security and integrity of BC Hydro’s data, customer and employee information, and digital systems. The team aligns BC Hydro’s technology solutions with cyber security control processes and NERC CIP compliance requirements.

The business management team ensures financial transparency, monitors and reports on performance and supports continuous improvement in the provision of technology services. This team is responsible for all aspects of technology governance including budget management, vendor and contract management, policies and standards management, workforce planning, risk management, business continuity planning, service portfolio management and records and information management.

5E.5.1.3. Delivery Department

This department is responsible for overseeing delivery of the technology capital investment portfolio including defining and ensuring compliance with project management standards, processes and procedures. The capital projects and work programs are described in Chapter 6, section 6.5. The delivery of capital initiatives typically includes operating expenditures related to early stage planning, project identification, analysis of alternatives, requirements analysis, change management, training, and data migration.

5E.5.1.4. Operations Department

The Operations department supports various technology applications that are enterprise-wide or used by multiple business groups. Activities carried out by this department include maintaining, sustaining, upgrading and optimizing enterprise applications such as customer support, financial, supply chain and human resource systems, project and portfolio management and smart metering applications.

This department is also responsible for the maintenance and sustainment of software and hardware related to data centers, including disaster recovery sites; personal computing and mobile devices; networks and other telecommunications equipment and systems; and cybersecurity monitoring and incident management.

This department's responsibilities include the technology help desk for general user support as well as business application support and service management.

5E.5.1.5. Smart Metering and Network Operations Department

The Smart Metering and Network Operations department is responsible for the day-to-day operation of the smart metering system. The department is responsible for data collection as well as device and network operations for approximately two million metering devices. This department also supports the meter-to-cash (e.g., billing) and energy conservation functions (by providing energy usage information), as well as energy loss and theft detection, power quality analysis, distribution grid use cases, and outage management functions.

5E.5.2 Overview of Operating Costs and FTEs

Table 5E-7 Technology KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Business Partner Services	5.4	0.0	16.9	0.0	4.8	0.0	0.0	**27.1**	43
2	Planning and Performance	7.8	0.0	2.5	0.3	0.1	0.0	0.0	**10.8**	58
3	Delivery	1.9	0.0	0.9	0.0	0.2	0.0	0.0	**3.0**	16
4	Operations	15.1	0.0	41.6	2.2	30.3	0.0	0.0	**89.2**	122
5	Smart Metering and Network Ops	3.0	0.0	0.6	0.0	0.0	0.0	0.0	**3.6**	24
6	**Total (Sch 5.5 L2, Sch 16.0 L31)**	**33.2**	**0.0**	**62.4**	**2.5**	**35.5**	**0.0**	**0.0**	**133.7**	**263**

As BC Hydro identifies opportunities to use technology to improve safety, reliability and productivity, the Technology KBU must manage the costs associated with these commitments while maintaining acceptable service levels. Primary technology cost-drivers include:

- **Software Licensing and Maintenance:** Software licensing and maintenance costs have increased by approximately 10 per cent between fiscal 2016 and fiscal 2019 due to market pricing, U.S./Canadian exchange rates, changes in licensing models and growth in the number of users;
- **Capital Investment in New and Existing Business Applications:** Higher application outsourcing, sustainment and maintenance costs are driven by new applications and enhancements to existing systems;
- **Infrastructure and End Point Devices:** As BC Hydro develops new technology solutions to improve reliability, safety and productivity, the foundational infrastructure to support these solutions (i.e. data centre servers, data storage and end point devices) must be expanded. For example, since fiscal 2016, data storage volume has grown from approximately 40 per cent from 2,000 terabytes to 2,900 terabytes. In addition, BC Hydro has provided

mobile devices to field workers, which has increased the number of these devices from 2,350 to 4,800; and

- **Cybersecurity:** Cost increases in this area have been largely driven by NERC compliance requirements as well as protection against an increased number and complexity of cybersecurity threats in the energy sector.

The Technology KBU has been able to maintain an appropriate level of service by implementing initiatives to offset the cost drivers described above. Examples of these initiatives, which are reflected in our revenue requirements, include:

- **Contract Re-negotiations:** BC Hydro has re-negotiated and renewed its data centre services contract to mitigate future costs over the next five years;
- **Consolidation of Infrastructure:** BC Hydro has initiated capital projects to eliminate data centre space at the Vancouver Internet Data Centre and consolidated racks and data center links at our Calgary Internet Data Centre. These initiatives resulted in approximately $0.8 million and $0.3 million in annual avoided costs, respectively;
- **Technological Improvements:** The implementation of next generation servers and storage devices has improved performance and capacity, resulting in more efficient use of equipment; and
- **Telecommunications Services Commoditization:** BC Hydro has been able to secure a reduction in rates for commodity technology services such as telecommunications data plans.

Operating costs of the Technology KBU by department are as follows.

5E.5.2.1. Business Partner Services Department

The labour budget for this department represents 43 FTEs. FTEs in this department charge approximately 13 per cent of their time to capital projects. These FTEs are organized across five teams and support approximately 200 business-specific technology systems and applications.

The services budget in this department funds external service providers for business application maintenance and sustainment. These external service providers perform, evaluate, prioritize and manage security, user-interface and platform stability improvements and upgrades across all business applications to maintain asset health and reliability.

This department also has a building and equipment budget for software licensing costs required for vendor support, security patches, and vendor-driven upgrades.

5E.5.2.2. Planning and Performance Department

The majority of the Planning and Performance department budget is related to labour costs for 58 FTEs. Employees in this department charge approximately 4 per cent of their time to capital projects.

- Four FTEs are responsible for strategic planning, investment benefits tracking, integrated investment planning, and portfolio and resource planning for BC Hydro's annual technology capital portfolio and five-year plan;
- Five FTEs are responsible for Enterprise Architecture including technology roadmap development and architecture standards and design;
- Three FTEs are responsible for infrastructure and telephony asset planning;
- Eight FTEs are responsible for cybersecurity planning including governance, risk and compliance;
- 10 FTEs are responsible for business planning, performance reporting, risk management, software asset management, business continuity and disaster recovery planning as well as the planning and implementation of continuous improvement activities;

- 20 FTEs in the Records Information Office manage BC Hydro's 3.2 petabytes of online and physical records including performing quality assurance, issuing approximately 60,000 drawings per year and circulating approximately 10,000 items per year; and
- Eight FTEs in the Vendor Management Office provide vendor relationship management and contract management, supporting a portfolio of approximately 90 vendors and a total average annual spend of approximately $200 million.

The budget for this department also includes funding for security testing, research and subscriptions.

5E.5.2.3. Delivery Department

This department delivers the Technology capital portfolio, which includes approximately 145 projects and work programs annually. The Delivery department workforce includes a mix of internal employees and external contractors. The labour budget for this department represents 16 FTEs. FTEs in this department charge approximately 37 per cent of their time to capital projects.

The non-labour budget for this department is primarily for contract resources to support Smart Metering Infrastructure end to end testing.

5E.5.2.4. Operations Department

The labour budget for this department represents 122 FTEs. Employees in this department charge approximately 10 per cent of their time to capital projects. Specifically:

- Two FTEs in this department represent the Chief Information Officer and an Administrative Assistant;
- 45 FTEs on the Enterprise Applications team operate, sustain and evolve approximately 100 enterprise-wide technology systems and applications used by BC Hydro employees and contractors;

- 35 FTEs on the Infrastructure, Cybersecurity Operations and Network and Telecommunication Operations team manage all enterprise-wide and business-specific BC Hydro Technology systems. This includes BC Hydro's 2,500 data centre servers. This team also manages approximately 8,200 desktop and laptop computers and 4,800 mobile devices across BC Hydro. In addition, this team is responsible for cybersecurity monitoring and incident response including the management of 280 firewalls, 23 Intrusion Detection System sensors, 10,000 Antivirus and Malware protection endpoints and two Security Event Monitoring Systems; and
- 40 FTEs on the Business Application Support and Service Management team respond to approximately 25,000 incidents and requests annually. Resourcing requirements for this team are driven by the continued need to operate, train and provide helpdesk support for critical technology systems.

This department's Services budget provides funding for the following costs:

- The development, sustainment and maintenance of technology enterprise applications;
- Data Center requirements including servers, pooled storage, middleware, racks and cybersecurity devices; and
- End Point Devices including service desk support, desktops, laptops, mobile devices and video devices.

This department's materials budget provides funding for the lease and usage of approximately 500 printers/copiers located throughout BC Hydro.

This department's building and equipment budget provides funding for the following costs:

- Software license and maintenance fees for enterprise systems and applications; and

- Communications and utilities services across BC Hydro including mobile phones services, landline services, telecom services, internet services, satellite services and hardware maintenance and support.

5E.5.2.5. Smart Metering and Network Operations Department

The majority of this department's budget is related to labour. This represents 24 FTEs, who manage over 2 million meters, approximately 8,000 mesh network devices as well as over 370 million pieces of data per day (e.g., consumption data, power quality attributes, safety and security alarms, and operational exceptions). This department operates in a near real-time capacity and facilitates the use of meter and field device data for BC Hydro's operational requirements including:

- Customer service operations functions including automated meter readings for residential, commercial, and industrial customer billing, demand billing, remote disconnect and reconnect, high bill and other customer investigations;
- Energy conversation programs including the energy conservation portal, in-home display solutions, and demand response pilots; and
- Energy loss and theft detection, load forecasting, power quality analysis, outage management, and distribution asset management.

Examples of improved business outcomes from Smart Metering Infrastructure include:

- 30,000 fewer estimated bills and 12,000 fewer invoices stopped each month for review by billing control processes;
- 3,200 vacant premises disconnected per month, which reduces the amount of electricity consumed that is potentially unbillable to customers; and
- 3,000 avoided truck dispatches for customer-side outages.

The non-labour budget for this department is primarily for contractor resources providing Smart Metering Infrastructure subject matter expertise and resource augmentation.

5E.5.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5E-8 Technology KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.5 L2	141.1	134.5	141.3	128.3	140.5	133.7	135.8	136.4
2	FTEs	16.0 L31	176	186	191	226	202	263	269	269

Operating costs are increasing by approximately $2.1 million from the fiscal 2019 forecast to the fiscal 2020 plan due to standard labour rate increases ($1.6 million) and budget transfers from other KBUs due to re-organization ($0.5 million).

Operating costs are increasing by approximately $0.6 million in fiscal 2021 compared to fiscal 2020 due to standard labour rate increases.

FTEs are planned to increase by six from the fiscal 2019 forecast to the fiscal 2020 plan due to the conversion of contractors to internal FTEs as part of the Workforce Optimization Program, which is discussed further in Chapter 5, section 5.6.1.

The increase in FTEs from the fiscal 2019 RRA to the fiscal 2019 forecast was also primarily driven by the Workforce Optimization program.

5E.6 Supply Chain KBU

5E.6.1 Responsibilities

The Supply Chain KBU supports safe, cost-effective and timely work at BC Hydro through the delivery of materials, vehicles and procurement services to all KBUs. Over the last decade, BC Hydro’s work and annual spend with our external suppliers has increased by more than 300 per cent from $650 million to over $2 billion due mainly to BC Hydro’s growing capital program. Supply Chain functions have become integral to delivering on key BC Hydro priorities such as capital plan delivery, ongoing reliable operations, safety and cost containment. BC Hydro uses suppliers to deliver equipment and materials such as transformers, generators, wire, electrical components and vehicles, as well as significant portions of work through services such as distribution line work, traffic management, vegetation management, security, information technology, engineering, vehicle maintenance and capital project construction. Meeting the needs of a BC Hydro that has become both an operations and project delivery company has required all areas of Supply Chain to evolve accordingly.

In fiscal 2013, in response to the growing criticality of Supply Chain functions to BC Hydro, BC Hydro started a multi-year implementation of an updated Supply Chain and Fleet Services Business Model. Implementation of the business model includes changes to people, processes and technology. A significant portion of the people and process changes are well underway or complete. The Supply Chain KBU is also responsible for the design and implementation of the Supply Chain Applications Project. Further details on this project are included in Appendix J.

The Supply Chain Applications Project will provide information technology and other tools for Supply Chain to help achieve a number of the remaining capabilities needed to fully operationalize the Supply Chain and Fleet business model. The Supply Chain Applications Project is currently being reviewed by the Commission in a separate proceeding.

The ongoing operations and improved capabilities of Supply Chain are having a positive impact on performance across BC Hydro while helping to control costs. Some examples of how Supply Chain supports BC Hydro in maintaining its strong reliability ratings and delivering its capital, maintenance and operations plans on schedule and within budget include:

- Improved logistics support to other departments across BC Hydro on an ongoing basis for planned work as well as during emergency events ensuring that BC Hydro is able to safely and efficiently complete work and respond quickly during outages and emergencies. For example, Supply Chain's logistics support during storms and wildfires includes ensuring that the materials needed to restore power are available to field crews at outage sites across the province, coordinating transportation and accommodation for goods and people who must be mobilized to respond, and emergency repairs of vehicles and equipment to keep staff operational throughout emergency events;

- Developing and implementing project supply chain strategies related to Stations, Lines and Interconnection projects to ensure materials and services required for these projects are available in a timely manner; and
- Developing and implementing category strategies which are estimated to provide approximately $16 million in cost avoidance and cost reduction benefits for fiscal 2019. Examples of category strategies include:
  - The Power Transformer Category strategy where BC Hydro created an improved contracting model, transportation management and quality management processes that together with improved contract and supplier management have greatly reduced transformer quality issues and supported on time project delivery. The same types of strategy elements are now being applied to other major equipment categories; and
  - Several of BC Hydro's category strategies for services have included "unitizing" the service which means creating hundreds of individual work units that represent the full range of services that could be required. This allows for more transparency into the costs of different work packages, supports market competitiveness and provides reliable information for work planning and budgeting to improve delivery of work.

The Supply Chain KBU is comprised of the following three departments:

- Procurement Department;

- Materials Management Department; and
- Fleet Services Department.

There have been no material changes to the responsibilities of the Supply Chain KBU since the Previous Application with the exception of the repatriation of the Accounts Payable function from Accenture in May 2018. This resulted in the transfer of approximately 23 FTEs to the Procurement department.

5E.6.1.1. Procurement Department

Overall, the Procurement Department has evolved to provide more strategic capabilities to respond to the needs of BC Hydro and to the increased complexities in the market. This includes more robust planning, analysis and supply market engagement.

The Procurement department is responsible for:

- Developing and executing supply chain related strategies, sourcing programs and project delivery strategies to support approximately $2 billion in annual enterprise capital construction, operational and maintenance needs;
- Developing and implementing category management processes and individual category strategic plans for BC Hydro’s key spend categories which incorporate strategy development, business process change, sourcing, and guidance on contract and supplier management. Examples of spend categories include power transformers, line services, vegetation management services, engineering services, security services, electrical components and distribution transformers;
- Leading Indigenous procurement policies and processes and working with the Indigenous Relations KBU to identify Indigenous procurement opportunities to meet commitments included in Impact Benefit Agreements and Relationship Agreements with First Nations;

- Developing, communicating and monitoring compliance with BC Hydro’s procurement policies and guidelines which incorporate the obligations under trade agreements that BC Hydro is a party to such as the Canadian Free Trade Agreement and the New West Partnership Trade Agreement;
- Managing several enterprise-wide programs such as travel, credit card and the contingent labour resource augmentation solution; and
- Managing BC Hydro’s Accounts Payable function following the repatriation of this function from Accenture in May 2018.

5E.6.1.2. Materials Management Department

This department provides the following services:

- Inventory forecasting and planning;
- Material distribution and transportation;
- Field warehouse operations;
- Disposition of assets at end of life from BC Hydro’s systems; and
- Waste transformer oil management.

This department has one main distribution centre located in Surrey, B.C. and services over 80 locations that cover the entire BC Hydro service area, requiring over 400,000 kilometers of travel each year. Over 50 per cent of our locations are serviced remotely from larger headquarters and require scheduled deliveries using complex transportation routes to replenish inventory levels over difficult terrain and remote islands.

Rigorous planning and inventory replenishment processes ensure that high service fill rates are achieved to support our crews performing restoration work and storm response. Our network provides business continuity with the management of spare parts and emergency inventories to ensure rapid response in the event of a system failure or natural disaster. BC Hydro's service fill rate as of December 2018 was 97 per cent and is currently in line with North America industry benchmarks of 96 per cent[262].

Materials Management is also required to procure inventory items that conform to unique specifications as a result of BC Hydro's system design. Achieving these objectives requires active contract management with key suppliers to realize on time delivery and quality specifications. Many of our materials have long-lead times such as power poles that require rigorous demand management to plan and distribute inventory for project work. Our Planning function manages inventory levels for approximately 39,000 inventory items that are situated across the BC Hydro network.

Materials Management also performs the pre-assembling of materials that involve staging, assembling, and kitting of inventory components to meet the needs of some capital projects.

5E.6.1.3. Fleet Services Department

The Fleet Services department is responsible for the procurement and life-cycle management of approximately 3,600 fleet assets (including vehicles, trailers and other equipment such as forklifts). The life-cycle management of fleet assets includes:

- Asset planning and acquisition;
- Engineering;
- Registration and insurance;
- Maintenance and repair;
- Vehicle fueling;
- Asset transfers and disposal; and

[262] PWC 2017 Utilities Materials Logistics Benchmark Study.

- Fleet supplier and contract management.

Fleet Services operates five main garages and also has mobile mechanics based out of 16 additional district offices.

5E.6.2 Overview of Operating Costs and FTEs

Table 5E-9 Supply Chain KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Procurement	19.3	0.2	3.1	0.1	0.0	0.0	0.0	**22.7**	161
2	MMBU	15.8	0.0	6.6	2.6	0.7	0.0	0.0	**25.6**	180
3	Fleet Management	12.7	0.0	13.8	16.3	0.4	0.0	0.0	**43.2**	109
4	Supply Chain Lead	0.9	0.0	0.9	0.0	0.0	0.0	0.0	**1.8**	4
5	**Total (Sch 5.5 L3, Sch 16.0 L32)**	**48.6**	**0.2**	**24.4**	**18.9**	**1.1**	**0.0**	**0.0**	**93.3**	**454**

5E.6.2.1. Procurement Department

Eighty-five per cent of the Procurement department’s budget is related to labour. This represents 161 FTEs. Total FTEs have increased by 40 from 121 FTEs in fiscal 2017 to 161 FTEs in fiscal 2019. Twenty-three FTEs were related to the repatriation of the Accounts Payable function from Accenture. Sixteen FTEs were related to the conversion of contractors to internal employees under the Workforce Optimization Program and were cost neutral.

Approximately 60 per cent of the Procurement department’s Services budget relates to contractor and supplemental labour to provide specialized expertise and resource augmentation for work peaks. The remainder of this budget relates to licence fees for program tools and external training fees.

The Procurement’s department operating cost budget has remained flat from fiscal 2017 to fiscal 2019 despite the large volume, increasing complexity of work and improved strategic support.

The 161 FTEs are divided into the following teams:

- 59 FTEs on the Category Management team develop and implement category management strategies that will best meet BC Hydro requirements and optimize value. These FTEs focus on the approximately 50 spend categories that are critical to BC Hydro and represent the majority of BC Hydro's annual supplier spend.

  When developing and executing specific category strategies, BC Hydro sets high-level objectives in eight areas to reflect what good performance would be in that specific category to meet BC Hydro's needs. The eight areas are: reliability, responsiveness, safety, organizational productivity and efficiency, First Nations, compliance and control, supplier performance and relationships and total lifecycle cost. Category strategies are driving improved performance in all these areas which is helping individual areas of BC Hydro and the company as a whole deliver their business priorities. As an example, improved supplier performance is helping to ensure safety, work delivery and reliability. Cost benefits in certain categories are helping to ensure BC Hydro can offset and/or contain costs within budgets;

- 28 FTEs on the Infrastructure Projects team are responsible for developing and implementing project procurement strategies for approximately 450 active projects related to Stations, Lines and Interconnection projects. Projects range in complexity and risk from simple to very complex and from low to high risk such as the Site C project. Approximately 80 per cent of the labour costs for these FTEs are charged directly to the capital projects they support; and

- 31 FTEs on the Purchasing team are responsible for supporting the thousands of procurement related transactions annually such as contract requests, releases and amendments that happen on a daily basis. They are also responsible for the smaller to medium sized and lower to medium complexity procurements. This mostly includes the sourcing of all materials over $25,000 as well as the sourcing of some short to medium term requirements for construction and other services.

Overall, the 118 FTEs on the Category Management, Infrastructure Procurement and Purchasing teams conduct approximately 30,000 procurement transactions each year including 260 public sourcing competitions and 450 secondary sourcing processes for suppliers pre-qualified through public competitions. These FTEs also develop and implement project procurement strategies for approximately 450 active projects and develop and implement category strategies that will cover approximately 80 per cent of BC Hydro's supplier spend.

The Supply Chain Central Services team that is also part of the Procurement group is composed of the following:

- Eight FTEs on the Procurement Policy, Compliance and Reporting team that develop, sustain, communicate and support compliance with procurement policies and guidelines across all of BC Hydro. This team provides training and interpretation guidance as well as reporting on Supply Chain metrics. The team maintains 16 policies and approximately 160 procedure and guidance documents and produces 20 reports on a weekly or monthly basis;
- 12 FTEs manage several enterprise-wide services, programs and contracts including:
  - The Bid Station which posts approximately 600 procurement-related bids and amendments on BC Bid each year and provides central collection of all Bid submissions;
  - The credit card program with 5,500 card holders and approximately 3,500 change requests per year including new card requests, suspensions, lost and damaged cards and card limit changes; and
  - The eCommerce program which allows for purchase orders and invoices to be sent electronically thereby reducing manual work for staff. This program

also allows suppliers to choose earlier payment options on approved invoices in exchange for a sliding scale discount. BC Hydro earns approximately $400,000 per year in discount revenues through the eCommerce program; and

- 23 FTEs on the Accounts Payable team. The Accounts Payable function was repatriated to BC Hydro in May 2018 from Accenture and costs that were previously shown as ABSU – Services are now shown as labour costs. The Accounts Payable team processes approximately 140,000 invoices per year.

  BC Hydro's Accounts Payable function scores favourably compared to other top performing organizations on several metrics. For example the number of invoices processed per FTE per year for BC Hydro is 6,086 compared to 4,706 for the top performing group in the American Productivity and Quality Centre benchmark. [263] BC Hydro's on-time invoice payment of 92 per cent is also above the 90 per cent average of other top performers based on a Hackett Group report.[264]

5E.6.2.2. Materials Management Department

Materials Management is a critical support function to provide materials related services to over 1,500 BC Hydro field employees as well as approximately 80 contractor crews that perform work across the province. The department manages approximately 350,000 transactions per year that include the issue, transfer and receipt of materials and also manage approximately $200 million of inventory spread across the province.

Overall the Material Managements operating cost budget has remained flat over the fiscal 2017 to fiscal 2019 period despite increasing work volumes and maintaining

[263] 2017 American Productivity and Quality Centre (APQC) benchmark, https://www.apqc.org/benchmarkig-portal/osb/accounts-payable-and-expense-reinbursement.

[264] The Hackett Group, https://www.zycus.com/knowledge-hub/research-reports/three-characteristics-of-top-performing-purchase-to-pay-organizations.html.

service levels. This is being achieved by continually evaluating its delivery processes and finding improvements such as:

- Centralized contractor fulfillment for Lower Mainland contractor crews;
- Optimization of the main distribution centre labor pool to service multiple work streams at BC Hydro including project materials; and
- Consolidation of Maintenance, Repair, Operations inventory at Field Stores to support crews and contractors.

The majority of this department's budget relates to labour costs for 180 FTEs. The number of Field Storekeepers at each location is aligned to BC Hydro's crew complements and transactional volumes to fulfill planned, emergent and maintenance work. The 180 FTEs are in the following functions:

- 27 FTEs are responsible for planning, acquiring and managing materials. These FTEs process an average of 225,000 inventory material requests each year, manage 39,000 catalogue items, process 18,000 purchase requisitions for catalogue and non-catalogue items each year and perform 30 inventory counts per year with close to 110,000 catalogued items counted. In addition, this team is responsible for managing approximately 130 contracts worth approximately $1.5 billion with over 100 suppliers;
- 77 FTEs in Regional Operations that support 60 regional field stores. This team manages 350,000 transactions each year related to the receipt of materials at the regional field stores and issuing materials to field crews across the province; and
- 76 FTEs in Central Operations that manage the delivery of materials to regional field stores with a monthly average of 80 scheduled runs via 16 routes to over 80 locations across the Province. This team also manages the disposals of materials and equipment, scrap materials recycling as well as oil management and wood recycling. BC Hydro processes between 1.5 million to 2 million

pounds of salvage materials each month, generating $4.5 million per year from the sale of scrap materials and $500,000 per year from the sale of recycled oil. The recycling of transformer oil and materials results in approximately 94 per cent diversion from landfills and our transportation network is optimized to leverage backhauls from outbound routes to return materials for salvage processing.

This department's Services – Other budget includes $4.2 million for third-party transportation costs to transport materials from the Main Distribution Centre to the regional field stores and $1.1 million for environmental contractors to handle used materials. The remainder of this budget funds travel for staff travelling between store locations to cover regional field stores that are not regularly staffed.

This department's Materials budget is largely composed of the annual provision for obsolete materials.

The budget for Buildings and Equipment is made up of storage fees and miscellaneous tools and equipment.

5E.6.2.3. Fleet Services Department

BC Hydro's fleet assets are relied on by diverse BC Hydro work teams, including over 1,500 operational crew members, doing planned and unplanned work (such as responding to storms and emergencies) safely and efficiently across the province. Almost 40 per cent of our fleet assets are located in smaller and remote locations and require use in off-road terrain such as transmission rights of way.

This department's labour budget represents 109 FTEs of which 85 per cent are union roles. These FTEs are in the following main functions:

- Nine FTEs are responsible for asset planning, acquisition, fleet engineering and supplier and contract management. This team develops and implements acquisition strategies, scans the market to keep abreast of new and green vehicle technologies, delivers on a Fleet capital spend of approximately

$30 million per year, manages contracts and relationships with 40 suppliers (with an annual operating and capital spend of approximately $60 million), participates in sourcing events to select suppliers, performs fleet safety and maintenance engineering, manages manufacturer recalls, updates vehicle specifications, and manages fleet initiatives such as trials of new heavy hybrid vehicles; and

- 100 FTEs deliver maintenance operations across the province to keep our fleet assets and BC Hydro staff operational. Approximately 1,900 (53 per cent) of BC Hydro's 3,600 fleet assets are maintained and repaired in-house and the remaining lighter-duty assets are outsourced for repair and maintenance through a fleet management supplier.

BC Hydro's specialized and heavy aerial units are safety-critical vehicles operated in proximity to high-voltage power lines by our field crews. To ensure the availability of these specialized units and safety of our crews BC Hydro predominantly performs in-house maintenance/repair of heavier assets and equipment including maintenance scheduling and mandatory annual testing. This in-house maintenance/repair is performed by employees that are skilled, red-seal-journeyed tradespeople, and are supplemented by the use of external heavy-vehicle chassis dealers across the province.

Feedback from our user groups has reflected the desire for greater vehicle availability and more Fleet mechanics in the field to support operational objectives. Since fiscal 2017, the number of FTEs in this department has increased by eight, largely as a result of cost neutral additions through the Workforce Optimization Program, such as the addition of mechanics at locations across the province to optimize vehicle availability. The Workforce Optimization Program is discussed further in Chapter 5, section 5.6.1. This program enables us to do more heavy work in-house where we can control the prioritization and turnaround of repairs on these critical assets and where costs (such as for parts) are lower. We also invest in specialized training for our mechanics in order for them to earn their Canadian Utility Fleet Mechanic certification and increase technical competency working on aerial equipment. To-date over 55 BC Hydro staff have earned this certification, and another 24 mechanics and apprentices are presently at various stages in the Utility Fleet Mechanic training/certification process.

The FTEs in this group also manage the outsourced maintenance and repair of light and medium duty assets; operate a Fleet parts room; administer BC Hydro's vehicle pools, asset insurance/registration renewals, asset transfers and disposals; complete commissioning on new heavy vehicles, and manage fuel, lubricant and carbon offset costs.

Each year, Fleet Services purchases 200 to 350 new assets annually for diverse user groups across the organization, completes approximately 33,000 vehicle work orders and 8,000 part orders, manages approximately 107,000 fuel transactions, and responds to approximately 150 accidents requiring repair coordination and cost recovery with ICBC.

In order to manage its budget and to support the objectives of its user groups Fleet Services continues to look for improvements to gain efficiencies. Recent examples include:

- Doubling the throughput in a mid-life maintenance inspection process;
- Implementing manufacturers' new vehicle programs to gain access to a larger network of certified outfitting vendors (who install specialized equipment such as winches, safety equipment and storage on new vehicles) and gain shipping efficiencies; and
- Ensuring that our maintenance program, personnel and facilities meet provincial Commercial Vehicle Safety & Enforcement standards to save money and vehicle downtime. This enables us to complete one mandatory commercial

inspection annually via internal staff at our own facilities versus the requirement for two inspections annually if vehicles had to go for external inspection.

The department's Services – Other budget includes $7.7 million for the costs of outsourced maintenance and repairs on light and medium assets, $2.1 million for asset registration and insurance costs with ICBC, $0.9 million for mandatory vehicle testing services provided by BC Hydro's subsidiary Powertech and carbon offset costs of $0.5 million. The remainder of this budget relates to mobile mechanic travel costs to maintain and repair assets in their assigned territories including remote locations, and vehicle lease costs.

The department's Materials budget primarily includes fuel costs of $10.6 million and parts costs of $5.4 million.

5E.6.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5E-10 Supply Chain KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.5 L3	91.8	89.9	92.2	89.0	93.0	93.3	94.5	95.5
2	FTEs	16.0 L32	402	421	402	447	402	454	468	468

Operating costs are increasing by approximately $1.2 million from the fiscal 2019 forecast to the fiscal 2020 Plan and by approximately $1.0 million from the fiscal 2020 plan to the fiscal 2021 plan, due to Standard Labour Rate increases.

FTEs are planned to increase by 14 from the fiscal 2019 forecast to the fiscal 2020 plan, primarily due to the establishment of an administrative/clerical pool to replace external contract resources. These temporary employees provide short-term coverage and are only paid for their time while on assignment. They charge all their time to the individual cost centres they are assigned to.

The increase in FTEs from the fiscal 2019 RRA to the fiscal 2019 forecast was primarily driven by the Workforce Optimization program, described in

Chapter 5, section 5.6.1 and the Accenture repatriation, described in Chapter 5, section 5.6.2.

5E.7 Business Unit Support KBU

5E.7.1 Responsibilities

The Finance, Technology and Supply Chain Business Unit Support KBU holds the budget for the Office of the Executive Vice President of Finance, Technology, Supply Chain and Chief Financial Officer.

5E.7.2 Overview of Operating Costs and FTEs

Table 5E-11 Business Unit Support KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	EVP, Fin, Tech, Supply Chain and CFO	0.7	0.0	0.1	0.0	0.0	0.0	0.0	**0.8**	3
2	**Total (Sch 5.5 L4, Sch 16.0 L33)**	**0.7**	**0.0**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.8**	**3**

5E.7.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5E-12 Business Unit Support KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.5 L4	0.8	0.7	0.8	0.7	0.8	0.8	0.8	0.8
2	FTEs	16.0 L33	3	3	3	3	3	3	3	3

Operating costs and FTEs are planned to remain stable during the test period compared to the fiscal 2019 forecast.

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Chapter 5F

Operating Costs
People, Customer, Corporate Affairs
Business Group

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5F.1 Introduction – People, Customer and Corporate Affairs Business Group

Chapter 5F provides and explains in detail the composition of, and rationale for the operating costs of the People, Customer and Corporate Affairs Business Group. The People, Customer and Corporate Affairs Business Group is one of six business groups in the organization and serves a Support function in the Plan-Build-Operate-Support model.

The People, Customer and Corporate Affairs Business Group budget was developed as part of the budgeting process outlined in Chapter 5, section 5.4. The information provided in this Chapter 5F demonstrates the basis for the entirety of the Business Group and KBU budgets, rather than focussing only on incremental cost requirements.

Chapter 5F is organized as follows:

- Section 5F.2 provides an overview of the organization and responsibilities of the People, Customer and Corporate Affairs Business Group;
- Section 5F.3 provides the operating costs and FTE information for the People, Customer and Corporate Affairs Business Group as a whole;[265] and
- Sections 5F.4 to 5F.11 provide more detailed information on the responsibilities, cost and FTEs for each KBU within the People, Customer and Corporate Affairs Business Group. The operating costs and FTE information for each KBU is broken out into two subsections:[265]
  - ▶ Overview of Operating Costs and FTEs – This subsection explains the starting operating costs and FTEs based on the fiscal 2019 forecast; and

[265] Please note the amounts presented in the tables in these sections may not add due to rounding.

- Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs – This subsection explains any incremental changes between fiscal 2019 forecast and fiscal 2020 and fiscal 2021 plan.

5F.2 Overview of People, Customer and Corporate Affairs Business Group Organization and Responsibilities

The People, Customer and Corporate Affairs Business Group is responsible for serving our customers and supporting our people. The Business Group's role includes:

- Attracting and retaining a high-performing, engaged workforce;
- Managing the experience of our 4 million residential, commercial and industrial customers as they interact with BC Hydro;
- Designing and implementing energy efficiency programs that enable and encourage all customer groups to conserve and manage the energy they use;
- Building relationships with the public, customers, external stakeholders, our regulator and our shareholder through ongoing communication and engagement opportunities;
- Ensuring compliance with regulatory standards and developing customer rates; and
- Managing commercial agreements and bilateral negotiations on behalf of BC Hydro.

The People, Customer and Corporate Affairs Business Group consists of the following KBUs:

Business Group	Key Business Unit
People, Customer and Corporate Affairs	Human Resources Customer Service Conservation and Energy Management Power Acquisitions and Contract Management Communications and Community Engagement Regulatory and Rates Ethics and Merit Office Business Unit Support

The People, Customer and Corporate Affairs Business Group is similar to the former Corporate Affairs KBU in the Previous Application with the following material changes:

- The addition of the Customer Service KBU from the former Transmission, Distribution and Customer Service Business Group;
- Business Planning and Risk is now part of the Finance KBU of the Finance, Technology and Supply Chain Business Group;
- Energy Planning is now part of the Energy Planning and Analytics KBU of the Integrated Planning Business Group; and
- The addition of the Enterprise Learning Department from the former Training, Development and Generation Business Group.

5F.3 Fiscal 2020 and Fiscal 2021 Plan Operating Cost and FTE Summaries

This section addresses planned operating costs and FTEs for the People, Customer and Corporate Affairs Business Group. The following are some key points of note with respect to the information provided in Figure 5F-1, Table 5F-1, Figure 5F-2, Table 5F-2 and Table 5F-3.

- The Customer Service KBU and the Human Resources KBU comprise over 75 per cent of the operating cost budget and over 65 per cent of the total FTEs for the People, Customer, Corporate Affairs Business Group. This reflects the repatriation of services from Accenture, which has delivered annual savings in excess of the expected savings and is discussed further in Chapter 5, section 5.6.2;

- Overall, labour costs make up over 65 per cent of the total operating costs for the People, Customer, Corporate Affairs Business Group; and
- Total operating costs are relatively flat from fiscal 2019 forecast to fiscal 2021 plan. Cost increases, primarily related to Standard Labour Rate increases and the Customer Crisis Fund, are offset by cost savings such as a reduction to advertising costs and reduced postage and printing costs due to paperless billing and other correspondence. The increases related to the Customer Crisis Fund are funded by the Customer Crisis Fund Rate Rider.

Planned operating costs for this Business Group are approximately $115.9 million in fiscal 2020 and approximately $117.2 million in fiscal 2021.

The operating costs for the People, Customer and Corporate Affairs Business Group are summarized by KBU in Figure 5F-1. Additional cost details are provided in Table 5F-1 below.

Figure 5F-1 People, Customer and Corporate Affairs Net Operating Costs by KBU (Fiscal 2020 Plan) ($ million)

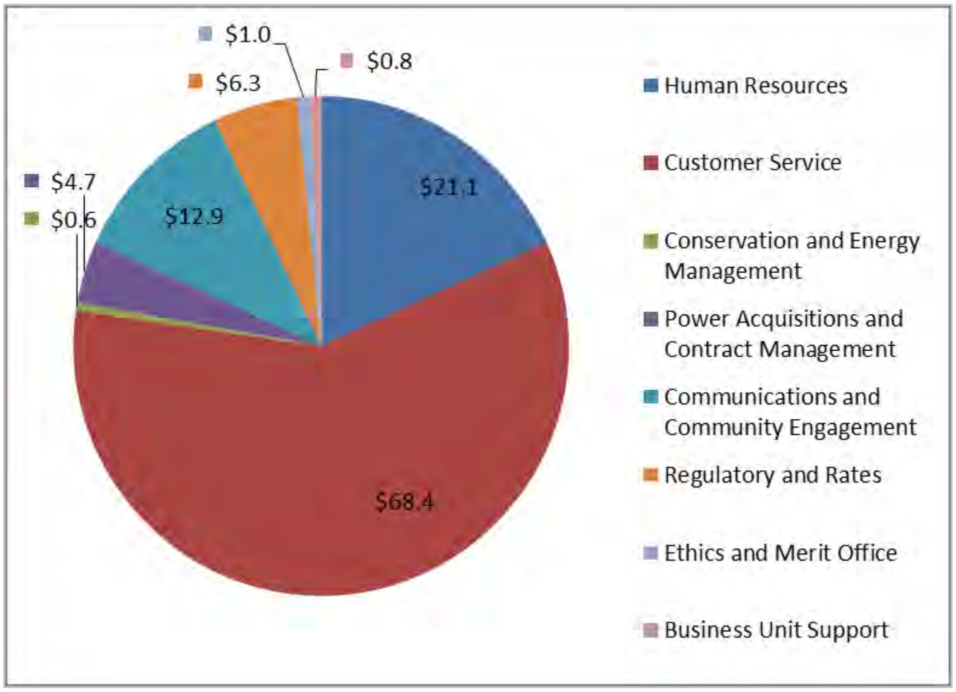

Table 5F-1 People, Customer and Corporate Affairs Net Operating Costs by KBU

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Human Resources	5.6 L1	22.9	21.6	23.1	22.1	23.3	21.1	21.1	21.4
2	Customer Service	5.6 L2+L13	76.2	68.9	73.6	68.7	73.8	69.0	68.4	69.1
3	Conservation and Energy Management	5.6 L3	0.6	0.6	0.6	0.5	0.6	0.6	0.6	0.6
4	Power Acquisitions and Contract Management	5.6 L4	4.6	4.6	4.7	4.9	4.8	4.8	4.7	4.7
5	Communications and Community Engagement	5.6 L5	12.8	12.4	12.6	13.7	12.7	13.6	12.9	13.0
6	Regulatory and Rates	5.6 L6	6.0	5.8	6.1	5.4	6.2	6.2	6.3	6.4
7	Ethics and Merit Office	5.6 L7	0.4	0.5	0.4	0.6	0.4	0.8	1.0	1.0
8	Business Unit Support	5.6 L8	0.7	0.8	0.8	0.7	0.8	0.8	0.8	0.8
9	Total	5.6 L15	124.3	115.2	121.8	116.8	122.5	116.9	115.9	117.2

The FTEs for the People, Customer and Corporate Affairs Business Group are summarized by KBU in Figure 5F-2. Additional details are provided in Table 5F-2 below.

Figure 5F-2 People, Customer and Corporate Affairs FTEs by KBU (Fiscal 2020 Plan)

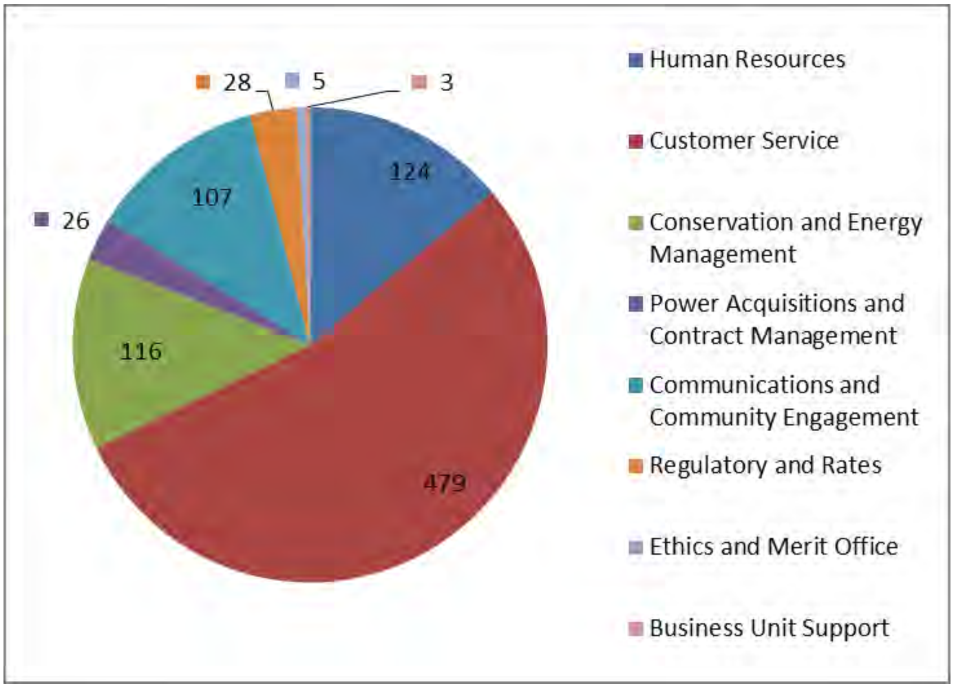

Table 5F-2 People, Customer and Corporate Affairs FTEs by KBU

	(FTEs)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Human Resources	16.0 L35	88	84	88	88	88	125	124	124
2	Customer Service	16.0 L36	124	154	124	191	124	495	479	479
3	Conservation and Energy Management	16.0 L37	114	110	112	112	112	116	116	116
4	Power Acquisitions and Contract Management	16.0 L38	23	26	23	28	23	27	26	26
5	Communications and Community Engagement	16.0 L39	86	94	86	95	86	107	107	107
6	Regulatory and Rates	16.0 L40	28	23	27	26	27	28	28	28
7	Ethics and Merit Office	16.0 L41	1	2	1	3	1	4	5	5
8	Business Unit Support	16.0 L43	3	3	3	3	3	3	3	3
9	Total	16.0 L44	467	497	463	545	463	906	887	887

Table 5F-3 below provides a continuity table which highlights changes to the People, Customer and Corporate Affairs Business Group from the Previous Application. An overall discussion of these changes, at a company-wide level, is provided in Chapter 5, section 5.5.2. Further details, by KBU, are provided in the sections below.

Table 5F-3 People, Customer and Corporate Affairs Operating Costs Continuity Schedule

	($ million)		F2020 Plan	F2021 Plan
1	F2019 Revenue Requirement Application Plan		-	
2	Reorganization Impacts		122.5	
3	F2019 Revenue Requirement Application Plan (People, Customer & Corporate Affairs)		122.5	
4	Budget Transfers Between Business Groups		(9.6)	
5	Customer Crisis Fund Operating Costs (Schedule 5.6, line 13)		4.0	
6	Adjusted F2019 Revenue Requirement Application Forecast (People, Customer & Corporate Affairs) / carry forward plan (Schedule 5.6, line 15)	A	116.9	115.9
7	Current Year Incremental Customer Crisis Fund	B	1.3	-
8	Current Year Budget Transfers Between Business Groups	C	(0.4)	
9	Test Period Savings			
10	Accenture repatriation savings		(1.2)	
11	Communications savings		(1.2)	
12	Paperless billing and customer correspondence savings		(1.0)	
13	Vacancy factor savings		(0.5)	
14		D	(3.9)	-
15	Test Period Cost Increases			
16	Labour		2.0	1.3
17		E	2.0	1.3
18	Net Increase/(Decrease)	F=D+E	(1.9)	1.3
19	Net Operating Costs (Schedule 5.6, line 15)	A+B+C +F	115.9	117.2

5F.4 Human Resources KBU

5F.4.1 Responsibilities

The Human Resources KBU is responsible for employee attraction and retention programs as well as supporting the productivity and engagement of our workforce through:

- Employee development;
- Performance management;
- Career and succession planning;
- Rewards programs;
- Health promotion and return to work programs; and
- Strong and effective relationships with our unions.

The responsibilities of this KBU have changed since the Previous Application due to the repatriation of Recruitment Services, Payroll Services and the Employee Service

Center from Accenture. The repatriation of services from Accenture is discussed in Chapter 5, section 5.6.2. In addition, the Enterprise Learning Department, which was previously part of the Learning and Development KBU, has moved to the Human Resources KBU. Lastly, the Change Management Department has moved from the Human Resources KBU to the Planning, Forecasting and Risk Department of the Finance KBU.

The Human Resources KBU is organized into five departments:

- Employee Relations Department;
- Recruitment Department;
- Enterprise Learning and Talent Management Department;
- Total Rewards and Systems Department; and
- Client Services Department.

5F.4.1.1. Employee Relations Department

The Employee Relations department is responsible for the overall labour relations strategy/management, collective agreement administration, union contract negotiations, policy development and governance, supporting managers/HR with workplace issues, and dispute resolution (e.g., arbitrations).

5F.4.1.2. Recruitment Department

The Recruitment department is responsible for the internal and external recruitment of employees through direct sourcing and by maintaining relationships with professional associations and educational institutions. With the repatriation of services previously performed by Accenture, this department now includes Recruitment Services which provides services such as screening candidates, overseeing background checks and coordinating interviews.

5F.4.1.3. Enterprise Learning and Talent Management Department

The Enterprise Learning team is responsible for non-technical and professional related training and leadership development. The Talent Management team is responsible for our diversity, engagement, talent management, performance and succession planning programs.

5F.4.1.4. Total Rewards and Systems Department

The Total Rewards and Systems department is comprised of the following teams: Total Rewards, Systems and Analytics, and Health and Recovery Services.

The Total Rewards team is responsible for the compensation, benefit, pension and time off programs that we provide to attract and retain employees. This includes the management of third party providers of benefits and pension services. With the repatriation of services previously performed by Accenture, this group now includes payroll, long-term disability, relocation and retiree benefit services.

The Systems and Analytics team is responsible for human resources information systems, and providing reporting, and data and statistical analysis. With the repatriation of services previously performed by Accenture, this group now includes the Employee Service Center which fields employee questions and processes employee transactions such as setting up new hires in our system.

The Health and Recovery Services team is responsible for health promotion and supporting the return to work of employees. This includes preventative wellness programs, return to work programs, attendance management and WorkSafeBC claims.

5F.4.1.5. Client Services Department

The Client Services department works directly with managers and employees to provide human resources support. This includes activities such as: supporting clients with human resources processes (e.g., performance management and succession planning), organizational design, leadership coaching, and addressing employee performance issues.

5F.4.2 Overview of Operating Costs and FTEs

Table 5F-4 Human Resources KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Chief Human Resources Officer	0.4	0.0	0.0	0.1	0.0	0.0	0.0	**0.4**	2
2	Employee Relations	1.2	0.0	0.0	0.0	0.0	0.0	0.0	**1.2**	8
3	Recruitment	2.5	0.0	2.1	0.0	0.0	0.0	0.0	**4.6**	22
4	Enterprise Learning and Talent Mgmt	1.9	0.0	1.6	0.0	0.1	0.0	0.0	**3.6**	12
5	Total Rewards and Systems	5.0	0.4	1.8	0.0	0.0	0.0	0.0	**7.2**	51
6	Client Services	4.0	0.0	0.1	0.0	0.0	0.0	0.0	**4.1**	30
7	**Total (Sch 5.6 L1, Sch 16.0 L35)**	**14.9**	**0.4**	**5.6**	**0.1**	**0.1**	**0.0**	**0.0**	**21.1**	**125**

Overall, BC Hydro has one Human Resources FTE for every 59 BC Hydro FTEs. This is comparable to ratios at other organizations. According to a recent HR Metrics Service report, the median rate for Canadian organizations is one Human Resources FTE for every 54 FTEs.[266] For comparison purposes, both ratios exclude payroll staff.

The goal of the Human Resources KBU is to attract, retain and engage the employees required to operate our business. The operating costs allocated to this KBU have been effective in meeting this goal and returning value to BC Hydro.

For example, BC Hydro's voluntary turnover rate is 1.1 per cent which is below the 3.8 per cent average for the Power and Utilities industry as reported by the Conference Board of Canada.[267] Minimizing turnover results in fewer replacement costs, and retains the specialized knowledge required to safely operate our system. In addition, our employee engagement score of 84 per cent exceeds the utilities industry average of 76 per cent. [268] A study by Gallup[269] found that businesses in the

[266] 2017 HR Annual Metrics Report, HR Metrics Service, 2017.
[267] MacLean, Kathryn, and Allison Cowan. Compensation Planning Outlook 2019. Ottawa: The Conference Board of Canada, 2018.
[268] Price Waterhouse Coopers – 2018 Employee Engagement Survey Results.
[269] Gallup Q[12]® Meta-Analysis Report, Gallup, https://news.gallup.com/reports/191489/q12-meta-analysis-report-2016.aspx.

top quartile of employee engagement outperformed bottom quartile businesses by 10 per cent in customer loyalty and engagement, 21 per cent in profitability and 20 per cent in productivity.

The FTEs in the Human Resources KBU remained stable at 88 from fiscal 2017 to fiscal 2018. The FTEs in this KBU increased to 125 in fiscal 2019 as a result of the Accenture repatriation discussed further in Chapter 5, section 5.6.2. As shown in Table 5F-5 below, in-sourcing these services reduced annual operating costs and is the primary reason that the overall KBU budget has reduced from $23.1 million in fiscal 2016 to $22.9 million in fiscal 2017 forecast.

5F.4.2.1. Chief Human Resources Officer Department

The majority of this department's budget is related to labour. This represents two FTEs: the Chief Human Resources Officer and an administrative assistant.

5F.4.2.2. Employee Relations Department

All of this department's budget is related to labour. This represents eight FTEs including one Manager, six Advisors, and one Administrative Assistant.

This group provides guidance and advice to the organization on managing complex and escalated labour relations issues, many of which take significant time to investigate and resolve over months or even years. Average annual work volumes include approximately 75 corrective action investigations, 30 workplace accommodations and 80 grievances and arbitrations. This group is also responsible for daily collective agreement administration and interpretation, negotiating settlements and other forward-looking workplace agreements (e.g., Memorandums of Understanding), as well as leading collective bargaining negotiations.

5F.4.2.3. Recruitment Department

Approximately 55 per cent of this department's budget is related to labour. This represents 22 FTEs as follows:

- Six FTEs in Recruitment Services. This group, which was previously outsourced to Accenture, is responsible for all interview coordination and candidate scheduling. This group schedules over 3,800 interviews and conducts over 1,200 background checks (including over 250 Drug and Alcohol tests) per year; and
- Sixteen FTEs in Recruitment. This team is responsible for all internal and external hires and fills approximately 1,800 positions per year. Recruitments are primarily to fill existing positions vacated from employees leaving the position (i.e., internal movement, termination, etc.) and not due to an increase in the number of overall positions or employees. As discussed in Chapter 5, section 5.6.4, the number of BC Hydro FTEs is expected to remain relatively flat over the test period, increasing by 72 in fiscal 2020 and decreasing by six in fiscal 2021.

  On average each recruiter manages 34 active vacancies, which is a higher volume compared to other organizations. According to a Society of Human Resources Management report, recruiters in other organizations manage a median of 25 recruitment requisitions.[270] The volume of hires at BC Hydro has increased approximately 18 per cent since fiscal 2016 due to capital projects such as Site C, and the expansion of our workforce due to the repatriation of services from Accenture and the Workforce Optimization program. To support this additional volume, two additional temporary FTEs have been added to this team since fiscal 2016. Additional recruitment volume will continue due to the repatriation of positions from Accenture and capital projects during the test period.

The department's Services – Other budget relates to employee relocation expenses, background checks, external recruitment agencies, recruitment advertising and

270 Mariotti, Andrew, *2017 Talent Acquisition Benchmarking Report*, Society for Human Resource Management, https://www.shrm.org/hr-today/trends-and-forecasting/research-and-surveys/Documents/2017-Talent-Acquisition-Benchmarking.pdf.

interview travel expenses. BC Hydro only utilizes external recruitment agencies for hard to fill positions. All other recruitment is performed by in-house recruiters.

5F.4.2.4. Enterprise Learning and Talent Management Department

Approximately 53 per cent of this department's budget is related to labour. This represents 12 FTEs as follows:

- Four FTEs in Enterprise Learning. This team provides enterprise-wide professional and leadership training for BC Hydro employees. Conducting this training in-house, and negotiating competitive pricing, results in lower costs than employees attending external training. For example, the cost per individual of a one-day professional training course delivered in-house is approximately $200 to $650, compared to the cost of a one-day professional training course at the University of British Columbia Sauder School of Business which can typically range from $800 to $1000; and
- Eight FTEs in Talent Management. This team provides a range of talent management programs. The primary focus of these programs is effective talent management and succession planning for various levels of management and critical roles to support business continuity. Programs such as talent management identify and prepare succession candidates for key positions that may be difficult to fill from the external market. For example, in 2018 our Director, Dam Safety retired. This would have been an exceptionally difficult position to hire from the external market due to its specialized nature, and is a critical position to ensure the safety of our dam facilities. We were able to fill the position internally with a candidate that had been identified via our talent management program.

The department's Services – Other budget relates to services provided for programs such as in-house leadership training, recognition programs, and the employee engagement survey. As an example of the benefit these services provide to BC Hydro, the employee engagement survey provides employees an opportunity to give feedback on what is working well and what could be improved. It also allows BC Hydro to take action to improve employee engagement and the effectiveness of our organization. This process is a key reason why our employee engagement exceeds the utilities industry average.

5F.4.2.5. Total Rewards and Systems Department

Approximately 69 per cent of this department's budget is related to labour. This represents 51 FTEs as follows:

- Two FTEs to support the department - one Manager and one Administrative Assistant;
- 18 FTEs the Systems and Analytics team which includes the Employee Service Centre. Eight of the FTEs work in the Employee Service Center. They process employee transactions (e.g., new hires) and respond to approximately 16,000 employee inquiries per year. The remaining FTEs support the Human Resources systems platform and related applications, and provide analytical support. In a typical year they handle 280 reporting requests and implement 250 system fixes and enhancements;
- 18 FTEs in Total Rewards. This team develops and administers all compensation, benefit and pension programs. Annually, this team manages over 170,000 employee payments, 15,500 payroll inquiries, 220 employee relocations and 135 employee retirements. This team also oversees the services provided by external vendors for pension and benefit administration which includes 250,000 employee benefit payments, and 42,500 benefit and pension inquiries per year. Eight of the FTEs in this group are payroll staff. According to a Deloitte report, this is lower than the industry average of 11 payroll FTEs for a company of BC Hydro's equivalent size;[271] and

[271] *The Payroll Operations Survey,* Deloitte, 2014, https://www2.deloitte.com/content/dam/Deloitte/us/Documents/human-capital/us-hc-payroll-operations-survey-summary-results-010715.pdf.

- 13 FTEs in Health and Recovery Services. This team provides health promotion services, such as health screens, to 2,900 employees per year. In addition they manage 1,100 sick leave cases, 700 WorkSafe BC claims and 670 recovery services cases per year, of various duration and complexity. Providing proactive health services and managing absences means that BC Hydro has a lower sick time than other public sector organizations. On average, employees have 7.0 sick days per year compared to the public sector average of 9.0 days according to a Conference Board of Canada report. [272] This lower sick leave usage equates to over $8 million in labour productivity savings per year. In addition, our return to work duration for more complex sick leave cases is four weeks compared to Sun Life's benchmark of 6.6 weeks.[273]

The department's Services – Other budget relates to vendors used to deliver pension and benefit administration, pension actuarial evaluations, drug and alcohol testing, immunization clinics, Surges fitness management, the employee family assistance program, expedited medical, and a WorkSafeBC claims management contractor.

5F.4.2.6. Client Services Department

The majority of this department's budget is related to labour. This represents 30 FTEs including two Human Resources Leads, two managers, two Human Resources Analysts, two Administrative Assistants and 22 Human Resources Business Partners. Client Services supports senior leaders, managers, and employees with annual Human Resources activities (e.g., performance management, succession planning), strategic business needs (e.g., talent assessments, senior leader development, organizational changes, vacancy and headcount management) and individual employee matters (e.g., employee

[272] MacLean, Kathryn, and Allison Cowan. *Compensation Planning Outlook 2019*. Ottawa: The Conference Board of Canada, 2018.

[273] Sun Life Financial Canadian Benchmark for fiscal 2018.

investigations). Overall, there is an average of one FTE in this department for every 235 BC Hydro employees.

5F.4.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5F-5 Human Resources KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.6 L1	22.9	21.6	23.1	22.1	23.3	21.1	21.1	21.4
2	FTEs	16.0 L35	88	84	88	88	88	125	124	124

Operating costs are planned to remain the same from fiscal 2019 forecast to fiscal 2020 Plan. Standard Labour Rate increases are offset by the reduction of one FTE, savings related to the Accenture repatriation (discussed further in Chapter 5, section 5.6.2), and vacancy factor savings (discussed further in Chapter 5, section 5.5.2.3).

Operating costs are increasing by approximately $0.3 million from fiscal 2020 plan to fiscal 2021 plan due to Standard Labour Rate increases.

Human Resources FTEs are planned to decrease by one from fiscal 2019 forecast to fiscal 2020 Plan. BC Hydro realized efficiencies in the Total Rewards and Systems team after taking over the work that was previously outsourced to Accenture. This enabled a transfer of one FTE to the Ethics and Merit Office KBU, to support additional requirements. Further information is provided in section 5F.10.

The increase in FTEs from fiscal 2019 RRA to fiscal 2019 forecast was primarily driven by the Accenture repatriation, described in Chapter 5, section 5.6.2.

5F.5 Customer Service KBU

5F.5.1 Responsibilities

The Customer Service KBU operates most of the key touchpoints for our residential, commercial and industrial customers as they interact with BC Hydro, including the customer-facing activities related to revenue collection. Customer Service works with other groups across BC Hydro to design, implement and operate services, processes, programs, systems and tariffs that make it easier for customers to do business with us.

In delivering our services we strive to balance:

- Maximizing revenue collection, by exploring and pursuing new load opportunities, retaining existing load, managing accounts receivable, and reducing electricity theft and losses;
- Meeting customers' service expectations, by understanding customer needs, removing barriers, and influencing the organization to incorporate customer perspectives; and
- Minimizing costs, by continuously improving our operational efficiency through the promotion of customer self-service and automation of manual tasks, and by following WorkSmart approaches to review and refine processes.

There have been three changes to the responsibilities of the Customer Service KBU since the Previous Application. First, the Distribution Design and Customer Connections department is now a separate KBU and was transferred into the Operations Business Group. Second, the Contact Centre and Billing Operations department was created to manage the functions previously outsourced to Accenture, as discussed further in Chapter 5, section 5.6.2. Third, the Economic Development team was transferred from the Power Acquisitions and Contract Management KBU to the Customer Service KBU.

The Customer Service KBU is comprised of the following six departments:

- Contact Centre and Billing Operations Department;
- Customer Analytics, Revenue and Risk Management Department;
- Customer Service Operations Department;

- Key Account Management Department;
- Large Customer Rate Operations Department; and
- Vice President, Customer Service Department.

5F.5.1.1. Contact Centre and Billing Operations Department

This department is responsible for day-to-day management of core customer services processes including:

- Ensuring the accuracy of 1.3 million electricity bills sent to customers each month;
- Operating BC Hydro's primary customer contact centre, which receives over 2.7 million calls each year. Customer service representatives answer 1.4 million of these calls and the remainder are resolved within the Interactive Voice Response system;
- Processing payment exceptions when payments cannot be automatically applied to accounts (e.g., cheques with incorrect account numbers, outdated pre-authorized banking information, or Electronic Funds Transfer errors);
- Performing collections activities ("dunning") to maximize the recovery of revenues, such as issuing late payment reminders, disconnecting services for non-payment, assessing security deposits, and participating in bankruptcy proceedings;
- Providing day-to-day support to customers and planning for usability and transactional enhancements to the MyHydro web portal, which allows customers to view and update account information on-line and enables more than 100,000 self-service transactions per month;
- Operating enhanced service channels such as the Business Account Services team and four in-person service offices; and

- Providing operational support and planning to the contact centre and billing teams by forecasting work volumes; developing staffing schedules that minimize labour costs while meeting wait and response time targets; managing training and process documentation; reviewing contact centre calls to enable coaching; and performing root cause analysis of escalations to understand how future issues can be avoided.

The department is also responsible for planning the ongoing improvements to business practices and processes for the above functions.

Contact Centre and Billing Operations' long-term objective is to improve the quality of its services while also reducing labour costs through the elimination of manual transactions and telephone calls when customers have self-service options. For example, continuing to develop and promote customers' use of online tools and increasing the resolution of customer inquiries on the first call will reduce inbound call volumes and manual processing. Customers benefit from greater access to electricity consumption and billing information, as well as the ability to perform transactions outside the contact centre's operating hours. Similarly, continuing to refine billing control and exception processes reduces labour requirements while also avoiding delays in customer billing.

The department was initially responsible for preparing for the transition of the customer service functions as part of the broader project to repatriate functions previously outsourced to Accenture, as well as for managing the customer service portion of the outsourcing Accenture contract until it expired on April 30, 2018. On May 1, 2018, the department assumed direct responsibility for all of those functions.

The Contact Centre and Billing Operations department is also responsible for the delivery of the Customer Crisis Fund pilot.[274] The Customer Crisis Fund pilot started in May 2018 and will operate until June 2021. The objective of the pilot is to allow for an assessment of whether the program is "sufficiently justifiable on an economic or cost of service basis."[275] The ongoing operations of the Customer Crisis Fund will be determined by the Commission following BC Hydro's submission of a program evaluation.

5F.5.1.2. Customer Analytics, Revenue and Risk Management Department

This department is responsible for the reduction of electricity theft and other non-theft revenue loss through distribution system metering and business intelligence tools including Smart Meter Infrastructure and a field inspection team. These activities include:

- Identifying, assessing and prioritizing analytics and human sourced leads for electricity theft, stolen meters and revenue losses, and performing field inspections;
- Quantifying theft and other revenue losses from completed field inspections;
- Recovering funds from parties responsible for theft, including managing the involvement in civil litigation and criminal cases related to electricity theft;
- Conducting proactive distribution feeder inspections and utilizing the energy inventory balance approach enabled by smart meters to prevent recurrence of theft from grow-ops;

[274] In the 2015 RDA Decision Order No. G-5-17, the BCUC directed BC Hydro to submit a proposal for a pilot program to assist residential customers facing short-term financial hardship in avoiding disconnection of their electricity service by providing grants. After a period of program design and stakeholder engagement, BC Hydro filed a Customer Emergency Fund Pilot Application in July 2017. Following a regulatory process, the Commission issued Order No. G-166-17, approving a dedicated rate rider for residential customers of approximately $0.25 per month to fund program grants and operating costs. The Order also approved the creation of the Customer Crisis Fund Regulatory Account.

[275] 2015 RDA Decision, Order No. G-5-17, pages 97 to98, January 20, 2017.

- Working with customers to address overloaded services and assist with customer safety and security related concerns;
- Identifying and resolving metering and billing errors; and
- Responding to local government requests for consumption information under the *Safety Standards Act*.

This department also manages the customer and energy analytics function. The volume of customer consumption and transaction data has increased significantly with the introduction of technologies such as smart meters and customer self-service capabilities. Analysis of this data allows us to make data-driven business decisions that improve customer service and reduce costs. These analyses include:

- Providing hourly load profiling and localized consumption information to assist with long-term business planning such as load forecast and demand-side management program development;
- Identifying detailed customer characteristics and consumption information to inform the Electric Tariff and rates designs;
- Leading the data collection and analyses for regulatory filings such as the assessment on the impacts of the Winter Disconnection Moratorium Pilot and the evaluation of the Customer Crisis Fund Pilot; and
- Supporting operating groups by providing insights that help improve or develop operational policies and business practices.

5F.5.1.3. Customer Service Operations Department

This department is responsible for the day-to-day management of core field-related customer services including:

- Providing manual meter reading services for approximately 45,000 non-automated meters and other field customer service work;

- Supporting the Operations Business Group to coordinate all meter exchanges and manage the planned outage notification processes; and
- Operating the Underground Locate Centre in accordance with the BC One Call Ltd. membership agreement[276] in support of safety and damage prevention. This team responds to property owner or contractor requests by sending site plans showing the exact location of BC Hydro's underground facilities.

The department also leads projects to improve our customer service or reduce costs, and looks to bring customer perspectives to certain cross-organizational projects. For example, the department is represented on BC Hydro's street light replacement program project team to bring a customer view to how the project is developed and implemented. In addition, Customer Service Operations is responsible for the timely response and resolution of escalated customer issues and claims investigations, working with stakeholders across BC Hydro to investigate, and find solutions and improve processes and customer service.

5F.5.1.4. Key Account Management Department

This department provides a single point of contact for BC Hydro's largest customers. Dedicated Key Account Managers support customers across all sectors of the B.C. economy including large industrial, commercial, institutional, government and municipal customers.

Key Account Management supports approximately 635 customers with nearly 59,000 accounts, representing almost half (46 per cent) of BC Hydro's domestic energy sales and more than one-third (38 per cent) of BC Hydro's revenue.

[276] BC One Call Ltd. is a not-for-profit corporation that enables public and worker safety, as well as the reduction in damages, by providing a single point of contact for contractors and members of the public to identify the location of underground equipment. BC Hydro, FortisBC, Telus and more than 300 other utilities and municipalities are members. BC One Call pre-screens requests to locate underground equipment and notifies BC Hydro when digging will occur in the vicinity of our assets, based on mapping we provide. BC Hydro then provides the requestor with drawings that indicate the exact location of our equipment.

Core customer service areas include new and expanded service connections, capital project and program delivery, billing and rate inquiries, and outage scheduling and notification. For example, in fiscal 2019, Key Account Management supported:

- Voltage conversion for approximately 100 customer vaults;
- Replacement of approximately 35 meters with PCBs at customer sites, as well as replacement of three transmission customer revenue meters;
- Negotiation of land lease agreements for 26 electric vehicle fast charging stations; and
- Adoption of paperless billing by approximately 52 per cent (as of January 2019) of the 45,000 consolidated billing accounts associated with Key Account customers.

Key Account Management also works with customers to identify opportunities for energy conservation, low carbon electrification and load retention and expansion. Key Account customers typically deliver about half of BC Hydro's energy savings target through participation in energy conservation programs. Key Account Management also oversees the contracts and deliverables of over 100 customer energy managers.

In addition, Key Account Management collects information on customers' business plans, market conditions, and other factors to inform BC Hydro's load forecast, and advances customer perspectives in rate and policy designs to remove barriers and attract or retain load.

5F.5.1.5. Large Customer Rate Operations Department

This department works primarily with BC Hydro's transmission customers to design, implement, manage and support a suite of rate schedules, tariff supplements and contracts for load interconnection and supply. This includes management and overall governance of:

- Rate Schedule 1823 Transmission Service – including maintenance of Tariff Supplement No. 74, Customer Baseline Load Determination Guidelines;
- Tariff Supplement No. 90 (Mining Customer Payment Plan);
- Rate Schedule 1892 Transmission Service - Freshet Energy; and
- Rate Schedule 1880 Transmission Service – Standby and Maintenance.

This department also manages the stakeholder engagement, regulatory approval and implementation of new and updated rate schedules and tariff supplements for BC Hydro's large industrial and other transmission service customers. It is also responsible for the negotiation and oversight of complex new business and commercial arrangements for large customer services.

5F.5.1.6. Vice President, Customer Service Department

In addition to providing the overall leadership to the Customer Service KBU, this department oversees the development of proactive strategies to power new industrial and large commercial customers and to retain and grow load from existing customers. This includes:

- Providing potential new customers with information on how to interconnect with BC Hydro;
- Facilitating load attraction initiatives to remove barriers for new customers; and
- Helping existing customers sustain or grow their businesses through rates, programs and business development opportunities.

The department also leads the development of transportation electrification strategies. This includes working with government ministries as well as with internal and external stakeholders on the development and operation of electric vehicle charging station infrastructure.

5F.5.2 Overview of Operating Costs and FTEs

**Table 5F-6 Customer Service KBU
Fiscal 2019 Forecast Operating Costs
and FTEs by Department**

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Contact Centre and Billing Operations	20.2	2.6	19.8	0.1	0.1	0.0	0.0	**42.7**	308
2	Customer Analytics, Rev and Risk Mgmt	4.8	0.0	2.3	0.8	0.6	0.0	0.0	**8.5**	38
3	Customer Service Operations	9.9	0.0	3.2	0.0	0.0	0.0	0.0	**13.2**	111
4	Key Account Management	2.3	0.0	0.1	0.0	0.0	0.0	0.0	**2.5**	28
5	Large Customer Rate Operations	0.6	0.0	0.1	0.0	0.0	0.0	0.0	**0.7**	4
6	VP, Customer Service	1.3	0.0	0.1	0.0	0.0	0.0	0.0	**1.4**	7
7	**Total (Sch 5.6 L2+L13, Sch 16.0 L36)**	**39.3**	**2.6**	**25.6**	**0.8**	**0.7**	**0.0**	**0.0**	**69.0**	**495**

5F.5.2.1. Contact Centre and Billing Operations Department

Approximately half of the Contact Centre and Billing Operations department budget relates to labour for operating BC Hydro's contact centre, billing, payments, and collections teams. The department also incurs costs related to service contracts (primarily postage and printing costs for electricity billing and non-billing correspondence); bad debt expense; and the Customer Crisis Fund Pilot.

A portion of these costs is offset by revenue received through the Account Charge, Reconnection Charge, Returned Payment Charge and Late Payment Charge, which are cost-based Standard Charges assessed to the customers. Incremental Customer Crisis Fund Pilot costs are fully offset by the Customer Crisis Fund Rate Rider.

Labour

The Contact Centre and Billing Operations department requires 308 FTEs to operate the contact centre, billing, payment and collection functions that were repatriated from Accenture. The labour plan for these services is based on a staffing snapshot provided by Accenture, which reflected the resources it needed to execute upon its contractual commitments.

Labour requirements are directly linked to call and transactional volumes, as well as the desire to provide customers with timely and accurate services. For example, customers phoning the contact centre expect to speak with an agent without waiting for an extended period. Similarly, customers expect billing inquiries or payment issues to be resolved quickly and without a high level of effort. As there can be significant variations in call and transactional volumes, staffing levels are actively managed with the objective of meeting targeted performance levels at the lowest cost.

BC Hydro has operated these functions for less than one year and is currently assessing and adjusting its processes and workforce for these functions based on operational performance. Staffing adjustments will continue to be made into fiscal 2020 as we gain experience with wait/response times, attrition rates, absenteeism and other factors.

These 308 FTEs can be categorized as follows:

- Two FTEs, the Director of the Contact Centre and Billing Operations department and an Administrative Assistant, provide overall management of this department;
- 203 FTEs are associated with the contact centre. Staffing consists primarily of Customer Service Representatives that are supervised by seven Front Line Managers and three Senior Managers. The span of control for Front Line Managers is approximately one manager for every 25 Customer Service Representatives.

  Contact centre staffing levels follow generally-accepted practices for contact centre management and are set predominately on the forecast volume and timing of in-bound customer calls, based on a target distribution of customer wait times. The contact centre aims to answer 75 per cent of calls within 30 seconds. Schedules and staffing levels are then adjusted to provide consistent levels of service in all hours and to limit the number of customers that could be impacted by extended wait times.

BC Hydro's contact centre performance target is similar to that of FortisBC, which uses a benchmark of 70 per cent of calls answered within 30 seconds for one of its approved Service Quality Indicators[277]. In the first nine months following repatriation (i.e., May 2018 to January 2019), BC Hydro answered 70 per cent of calls in 30 seconds;[278]

- 49 FTEs are associated with the billing and payments functions. Billing and payments are highly automated. Most invoices are generated and issued to customers without manual intervention. Similarly, most payments are processed through systems integrations with financial institutions. However, manual intervention is required when payments are not successfully applied to customer accounts or when bills are stopped before being issued because control points are triggered (e.g., consumption is significantly higher than historical patterns or requires a change to a customer's rate). Accordingly, resource requirements are based on associated work volumes and customer response times.

BC Hydro aims to investigate and resolve stopped bills within 10 days and payment exceptions within five days. In the first eight months after repatriation the payments team investigated and resolved approximately 130,000 payment exceptions. In addition, in calendar 2017, the billing team investigated and resolved 112,000 bills that were stopped because control limits were triggered.

BC Hydro continually works to refine billing controls to balance the cost of manual reviews with the risk of inaccurate billing. For example, the number of stopped bills was reduced by 49 per cent when billing controls were adjusted following the automation of meter reading through smart meter implementation, recognizing the near elimination of manual data entry errors. Labour savings have also been achieved through simplification of the Medium General Service

[277] FortisBC Energy Inc. Multi-Year Performance Based Ratemaking Plan for 2014 through 2018, Order No. G-138-14, page 152 from September 15, 2014.

[278] Excludes contact centre performance during the extreme storm restoration from December 20 to 31, 2018.

and Large General Service rates, and by the automation of service order completion;

- 16 FTEs are responsible for collections activities. Actively managing accounts with overdue balances is a key aspect of minimizing uncollectible revenue and avoiding bad debts.

  In the first nine months after repatriation, this team performed over 130,000 manual reviews of accounts with overdue balances, at an advanced status in the dunning process. This is in addition to over 320,000 automated reviews of overdue accounts conducted by the billing system. This team also processed nearly 400 residential and commercial bankruptcies, which involves working with customers or trustees to close accounts, provide final bills as a “proof of claim”, and re-establish accounts in the name of a trustee when necessary;

- Seven FTEs spend time on the Customer Crisis Fund Pilot. Labour requirements are primarily based on the volume of applications received. Dedicated resources are not assigned to the Customer Crisis Fund team; instead, labour is provided by other teams in the Contact Centre and Billing Operations department and incremental hours worked are charged to the pilot program;

- 27 FTEs are responsible for workforce planning, knowledge management, quality assurance, training, timesheet administration and other support to the operational teams.

  Since repatriation this team has identified about 1,000 changes to business processes and made more than 3,300 changes to process and training documentation. The team has also performed quality assurance reviews for 6,400 customer calls and billing transactions, held over 400 peer coaching sessions, and provided instructor-led training to five classes of new Customer Service Representatives; and

- Four FTEs provide operational reporting and analysis, and are also responsible for process improvement and implementation of initiatives that improve revenue collection, reduce costs or improve customer service.

Service Contracts

Service contracts for this department are budgeted at $19.8 million, the largest component being $8.1 million for postage, printing and paper. Other significant costs include $5.8 million for bad debt expense and $3.4 million for bill credits associated with the Customer Crisis Fund Pilot. In addition, service contract costs include payment processing; credit checks; collection agency commissions; contact centre customer satisfaction surveys; and translation services.

The budget for postage, printing and paper is driven primarily by the number of customers that elect to receive paper bills. Other factors include the volume of non-billing correspondence, Canada Post's postage rates, and printing/paper costs. BC Hydro regularly promotes the adoption of paperless billing during telephone interactions with customers, as well as through online and social media channels. Campaigns and incentives are also used periodically. As a result of these efforts, as of January 2019, about 55 per cent of non-consolidated accounts receive their bills electronically. This is the highest rate of paperless adoption amongst Canadian electric utilities participating in the Canadian Electricity Association's Customer Council. Paperless billing for consolidated accounts was made possible through the Enterprise Billing Infrastructure Project, which went live in February 2018. In the first 11 months, over 29 per cent of consolidated accounts converted to paperless billing.

As a result of BC Hydro's efforts to support paperless billing, postage, printing, and paper costs decreased by approximately 20 per cent between fiscal 2016 and fiscal 2018, despite annual increases in Canada Post charges. BC Hydro estimates that paperless bill delivery saves BC Hydro customers over $7 million each year.

Costs for other service contracts are managed primarily by encouraging customers to use pre-authorized or electronic banking payments instead of cheques. 94 per cent of payments are currently made by pre-authorized or electronic payments. In addition, BC Hydro pays collection agencies by commission so that costs are not incurred unless agencies are able to recover unpaid bills, which provides a corresponding benefit to bad debt.

Bad Debt Expense

This includes bad debt expenses associated with residential and general service customers. Bad debt expense is affected by external factors such as economic conditions and unemployment. Bad debt is also affected by BC Hydro's collection practices (including practices for non-payment disconnections), as well as security deposit and installment plan policies.

As shown in Table 5F-7 below, bad debt costs decreased from $8.7 million in fiscal 2015 to $5.8 million in fiscal 2018. This decrease is primarily the result of improved collections practices made possible by smart meters which provide remote disconnect and reconnect capabilities. BC Hydro's residential and commercial bad debt expense, as a percentage of revenue, is amongst the lowest of Canadian utilities.[279]

Table 5F-7 Bad Debt Expense, Fiscal 2012 to Fiscal 2018

($ million)	Fiscal Year						
	2012	2013	2014	2015	2016	2017	2018
Bad Debt Expense	6.782	6.949	7.209	$8.746	5.861	4.364	5.815
Bad Debt as a Percentage of Revenue	0.25	0.23	0.23	0.27	0.17	0.12	0.15

[279] BC Hydro 2015 Rate Design Application. BC Hydro Final Argument dated October 11, 2016, p. 16; Exhibit B-26-1, Attachment 1, IR 1.192.1, Figure 1; Exhibit B-26-1, p. 41; Transcript Volume 7, p. 1208, corrected in Exhibit B-58-1.

5F.5.2.2. Customer Analytics, Revenue and Risk Management Department

This department is managed by one senior manager who oversees three teams: Revenue Assurance, Field Inspection, and Customer and Energy Analytics. Approximately 60 per cent of this department's budget is related to labour costs. The remainder includes contractors, travel and materials required by the field staff as well as software, services, and warranty costs related to check meters.

Revenue Assurance and Field Inspection Teams

The Revenue Assurance and Field Inspection teams total 26 FTEs. These include:

- Seven FTEs that identify leads for field inspection;
- Three FTEs that are responsible for revenue recovery; and
- 16 FTEs that carry out all field activities associated with the revenue assurance program.

BC Hydro has dramatically reduced theft from marijuana grow-ops by leveraging the tools provided by the Smart Metering and Infrastructure program. Currently, most thefts occur from typical residential and commercial customers: fewer than 5 per cent of grow-ops are now believed to participate in electricity theft, compared to over 60 per cent of grow-ops prior to the installation of smart meters. Accordingly, BC Hydro has been able to reduce Field Inspection FTEs by approximately one-third since fiscal 2014.

BC Hydro continues to require a robust revenue assurance program to prevent recurrence of thefts from grow-ops, as well as to reduce theft and revenue leakage from normal residential and commercial customers. During fiscal 2018, approximately 2,700 investigations were performed related to suspected electricity theft and revenue loss at individual premises. From these investigations, 112 thefts were identified and stopped. The Revenue Assurance team also identified and resolved 85 back-billings related to metering and billing errors.

In addition, the Revenue Assurance and Field Inspection teams now play key roles in identifying and mitigating public and employee safety risks as a result of unsafe electrical services. In fiscal 2018, BC Hydro conducted 244 investigations related to safety risks from potentially overloaded services. After being contacted by the Revenue Assurance team, 42 per cent of these customers voluntarily reduced load or obtained a service upgrade, while 9 per cent of overloaded service investigations resulted in a disconnection to mitigate safety risk. In the remaining cases, the customers' electrical services were not found to be overloaded but in many instances the investigation still led to the resolution of safety issues or the identification of overloaded BC Hydro equipment.

Customer and Energy Analytics Team

The Customer and Energy Analytics team includes 10 FTEs, comprised of one manager and nine data scientists and analysts.

In 2018, the Customer and Energy Analytics team fulfilled 180 Customer Data Requests from internal BC Hydro departments. In addition, the team completed 23 complex projects requiring analysis of customer and energy data, which supported data-driven decisions related to rate design, business practices, and allocation of operational resources.

5F.5.2.3. Customer Service Operations Department

Approximately 75 per cent of this department's budget is relates to labour for 111 FTEs. This department is managed by one senior manager who oversees the following three main functions: field related customer services; customer escalations and claims; and strategic projects, policy and reporting.

The remaining budget includes funding for strategic projects to improve the service we provide or lower costs, travel and materials required by field services, payments to BC One Call, and claims against BC Hydro for damages.

Field Related Customer Services

This function consists of 85 FTEs, including one senior manager, as follows:

- 70 FTEs are responsible for field customer service functions that ensure the timely and accurate recording of consumption used for customer billing.

  Three field managers manage 52 FTEs located in 35 offices across the province. The span of control for Front Line Managers is approximately one manager for every 17 Field Service Representatives. In fiscal 2018, these FTEs conducted 311,000 manual meter reads for meters that are not read automatically. In addition, they performed 14,000 other field service orders for on-site investigation for billing inquiries, non-electrical meter maintenance, and manual single-phase meter disconnections and reconnections. BC Hydro continues to find labour savings by leveraging this cost-effective field resource to perform more non-technical field customer service work.

  The remaining 14 FTEs are responsible for management, planning, scheduling, dispatching, continuous optimization, training, safety, and reporting. This includes two FTEs converted from contractors as a result of Workforce Optimization to administer customers' keys so that employees and contractors can access BC Hydro equipment in buildings and behind locked gates. This team also supports the Operations Business Group to perform the coordination, facilitation, exception management and customer communications for time-expired, failed, and compliance sampling meter exchanges.

  As discussed in Chapter 5, section 5.6.2, BC Hydro in-sourced the field customer service function from Accenture in fiscal 2017. At the time, BC Hydro undertook a third-party optimization study to determine the most efficient office locations and corresponding resourcing requirements. These changes as well as the ongoing optimization of our meter reading routes created efficiencies and increased productivity. As a result, the annual budget for this function reduced from $8.4 million in fiscal 2017 to $6.9 million for fiscal 2019.

BC Hydro's meter reading performance targets are to issue at least 99 per cent of bills using actual meter readings and to issue no more than 0.5 per cent of bills on billing system estimates for consecutive billing periods. These metrics are generally comparable to FortisBC's approved Service Quality Indicator of Meter Reading Accuracy of 97 per cent.[280] As of December 2018, BC Hydro has approximately 6,900 billing system consecutive estimates, representing 0.3 per cent of all bills. Of those, the consecutive estimates from manually read meters decreased by 41 per cent from 4,516 in fiscal 2017 to 2,666 in fiscal 2019;

- Nine FTEs support BC Hydro's membership in the BC One Call organization to provide the locations of BC Hydro's underground facilities to property owners and contractors with a required response time of three days. The volume of BC One Call requests has increased from 166,000 in fiscal 2017 to 182,000 in fiscal 2018 to a forecast of approximately 200,000 for fiscal 2019. Payments to BC One Call are charged on a volumetric basis and, accordingly, BC One Call costs increased from $325,000 in fiscal 2018 to $444,000 in fiscal 2019. However, FTEs have remained constant as BC Hydro has been able to improve productivity through automation of certain aspects of the process;
- Three FTEs are responsible for processing approximately 1,000 requests each year for customer initiated vault maintenance disconnections and incentives for pad mounted transformer decoration. BC Hydro provides an incentive program to decorate pad mounted transformers to prevent graffiti on equipment and to blend in with surroundings. Vault maintenance disconnection work generates approximately $0.6 million per year in revenue to BC Hydro; and
- Three FTEs are responsible for engaging with commercial customers that may be significantly impacted by planned outages. Approximately 2,900 planned

[280] FortisBC Energy Inc. Multi-Year Performance Based Ratemaking Plan for 2014 through 2018, Order No. G-138-14, page 152 (pdf page 166) from September 15, 2014.

outages each year involve commercial customers, and over 1,100 have potentially significant customer impacts.

Customer Escalations and Claims

This function consists of 13 FTEs as follows:

- Four FTEs manage approximately 550 complex escalations per year from the BCUC, government officials and the Office of the Ombudsperson. Our response time target for most escalations is five business days.[281] This team also provides quarterly reporting to the BCUC on escalation volume and response time; and
- Nine FTEs, including one manager, are responsible for resolving approximately 1,000 claims made against BC Hydro for damages to personal or business equipment or property each year, as well as for approximately 1,000 claims made by BC Hydro against third parties for damages to BC Hydro plant and equipment. BC Hydro expects to recover approximately $5 million dollars of damages in fiscal 2019.

Strategic Projects, Policy and Reporting

BC Hydro looks for opportunities to make it easier for customers to do business with us.

- Five FTEs lead customer projects and programs that enhance customer support, remove customer barriers, and improve operational efficiency. Examples include planning and delivering BC Hydro's paperless billing campaigns; executing targeted customer communications; developing and maintaining customer service web pages; and acting as business leads in technology projects such as the Customer Mobile and Enterprise Billing Infrastructure Project;

[281] Complex issues that are dependent on subject matters experts have a target of 10 business days.

- Four FTEs lead BC Hydro's initiatives to create a customer-centric work force. This includes various customer engagement activities such as interviews, workshops, surveys and focus groups. This team also works with project teams across BC Hydro so that the customer perspectives are considered and incorporated early in the project life cycle. Examples include the customer engagement work undertaken for the street light replacement program and the voltage conversion program. In fiscal 2019, this team also expects to deliver customer service training to approximately 1,250 BC Hydro employees; and
- Three FTEs provide policy instructions and directions to the customer operations teams. This includes setting up controls for compliance with the Electric Tariff and customer policies, advancing customer and operational perspectives in BC Hydro's distribution rate design applications and implementing rate and Electric Tariff changes. In addition, this team provides monthly reporting on key performance indicators and targets for the Customer Service KBU.

5F.5.2.4. Key Account Management Department

This department consists of 28 FTEs. Key Account Managers support customer participation in BC Hydro's conservation and energy management programs and approximately 50 per cent of the labour costs for these FTEs is funded by BC Hydro's DSM programs. Chapter 10 details BC Hydro's DSM expenditure schedule request.

On average, each Key Account Manager supports approximately 30 customers. However, each portfolio varies depending on the complexity or volume of customer service needs.

The Key Account Management department reduced from 38 FTEs in fiscal 2014 to 28 FTE in fiscal 2019, a reduction of approximately one-quarter. This was as a result of a review of customers served by Key Account Managers to ensure alignment with BC Hydro's current priorities. Following the review, a number of customers previously served by Key Account Managers were transitioned to be supported by the contact centre's Business Account Services team.

5F.5.2.5. Large Customer Rate Operations Department

The Large Customer Rate Operations department is comprised of four FTEs.

Labour requirements are driven by the activities required to operate, maintain and ensure compliance with the complex rates and tariffs that define how BC Hydro's transmission customers pay for service. For example, each year this department reviews and establishes the Customer Baseline Load (**CBL**) for approximately 100 transmission voltage customers taking service under the stepped rate provisions of Rate Schedule 1823. This effort requires direct interaction with each customer, in addition to preparing and supporting BC Hydro's annual application to the BCUC for CBL approval.

Labour requirements are also determined by the level of analysis and engagement necessary to develop and implement new rates and tariff supplements, as well as for the negotiation of new commercial agreements. These provide transmission customers with options to improve their competitiveness while benefitting all BC Hydro customers through the attraction and retention of load and revenue. Recent examples led by this department include Tariff Supplement No. 87 and No. 88 (Indirect Interconnection Service), Tariff Supplement No. 90 (Mining Customer Payment Plan) and Rate Schedule 1892 (Transmission Service - Freshet Energy). This department also prepares the required compliance filings to the BCUC, such as the Final Evaluation Report for the Freshet Rate Pilot.

5F.5.2.6. Vice President, Customer Service Department

Almost all of the costs in this department are related to labour costs for seven FTEs. Two FTEs, the Vice President of Customer Service and an Administrative Assistant, provide overall management for the Customer Service KBU. The remaining five FTEs are allocated as follows:

- Three FTEs on the Business and Economic Development Team. This team provides a single point of entry into BC Hydro for prospective energy-intensive customers and helps them to understand our interconnection process, rate schedules and tariff supplements. Since January 2018, BC Hydro received 336 inquiries totaling more than 11,000 MW of load from energy-intensive industries such as fuel processing, cannabis, cryptocurrency operators and data centres. The team identifies suitable brownfield sites for energy-intensive customers and helps prospective customers avoid siting load in capacity-constrained areas. In fiscal 2019, 6 MW of new load has been connected at brownfield sites and an additional five projects, totalling 105 MW, have proceeded to the study stage; and
- Two FTEs on the Electric Vehicle team. This team is responsible for improving the overall electric vehicle customer service in primary customer touchpoints and at the 56 fast charging stations owned by BC Hydro. This team also works with governments, businesses and other stakeholders to remove barriers to the adoption of electric vehicles in B.C.

5F.5.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5F-8 Customer Service KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.6 L2+ L13	76.2	68.9	73.6	68.7	73.8	69.0	68.4	69.1
2	FTEs	16.0 L36	124	154	124	191	124	495	479	479

Operating costs are decreasing by approximately $0.6 million from fiscal 2019 forecast to fiscal 2020 plan. This includes the following cost decreases:

- $1.0 million in further savings related to the Accenture repatriation, as discussed in Chapter 5, section 5.6.2;

- $1.0 million due to a further reduction in paper, printing and postage costs resulting from an increase in paperless billing and other forms of correspondence;
- $0.3 million of vacancy factor savings, as described in Chapter 5, section 5.5.2.3; and
- $0.2 million related to re-organization impacts. Two FTEs are being transferred to the Customer Service KBU from other KBUs and six FTEs are being transferred from the Customer Service KBU to other KBUs, primarily to support NERC CIPv5 compliance requirements, as described in Chapter 5C, section 5C.10.3.

These cost decreases are partially offset by the following cost increases:

- $1.3 million to fund the first full year Customer Crisis Fund Pilot (the program was not in operation for the first three months of fiscal 2019). This increase is offset by an equivalent adjustment to miscellaneous revenue for the rate rider which funds this program; and
- $0.6 million related to Standard Labour Rate increases.

Operating costs are increasing by approximately $0.7 million from fiscal 2020 plan to fiscal 2021 plan, due to Standard Labour Rate increases.

Customer Service FTEs are planned to decrease by 16 from fiscal 2019 forecast to fiscal 2020 plan. In addition to the net reduction of four FTEs from the re-organization transfers described above, the Contact Centre and Billing Operations department is reducing by 12 FTEs based on experience gained to date on staffing requirements after repatriation of these functions from Accenture.

Customer Service FTEs are planned to remain constant from fiscal 2020 plan to fiscal 2021 plan.

Operating costs decreased by approximately $4.8 million from fiscal 2019 RRA to fiscal 2019 forecast, primarily because paper, printing and postage costs were lower than anticipated and because actual savings from the Accenture repatriation have been higher than originally projected.

The increase in FTEs from fiscal 2019 RRA to fiscal 2019 forecast was primarily driven by the Accenture repatriation, described in Chapter 5, section 5.6.2.

5F.6 Conservation and Energy Management

5F.6.1 Responsibilities

The Conservation and Energy Management KBU is responsible for a range of activities that encourage customers to manage their energy consumption and help them to reduce their energy bills. These activities include energy efficiency and conservation, capacity-focused initiatives, and low carbon electrification. Collectively, these activities are referred to as demand-side management (**DSM**).

BC Hydro's DSM expenditure schedule request is set out in Chapter 10. There have been no changes to the responsibilities of the Conservation and Energy Management KBU since the Previous Application.

5F.6.2 Overview of Operating Costs and FTEs

Table 5F-9 Conservation and Energy Management KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Conservation and Energy Management	0.5	0.0	0.1	0.0	0.0	0.0	0.0	**0.6**	116
2	**Total (Sch 5.6 L3, Sch 16.0 L37)**	**0.5**	**0.0**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.6**	**116**

Employees in Conservation and Energy Management support BC Hydro's DSM activities. Therefore, nearly all labour costs are classified as deferred operating expenditures and are charged to the DSM Regulatory Account. The deferred operating expenditures are not included Table 5F-9.

The operating budget shown above is primarily made up of labour costs totalling $0.5 million for overall management and administration of the KBU. In addition, the budget includes incidental expenses of $0.1 million that indirectly support DSM activities. This operating budget of $0.6 million has been unchanged since fiscal 2016.

FTE levels for this KBU have remained stable since they were assessed and reduced as part of the moderation strategy for DSM expenditures identified in the Previous Application. The KBU consists of 116 FTEs as follows:

- Two FTEs represent the Director of Conservation and Energy Management and an Administrative Assistant;
- Eight FTEs in the Strategic Planning Department. This department develops long-term DSM resource options to support BC Hydro's Integrated Resource Planning process, produces estimates of the potential for DSM in BC Hydro's service territory, establishes the framework for the DSM Plan, performs annual updates of the DSM Business Plan, provides modelling support and cost-effectiveness analysis for the KBU's governance and decision making processes, supports DSM policy development, prepares regulatory applications and supports other regulatory processes;
- 30 FTEs in the Marketing (Program Management) department. Staffing requirements for this department are determined by the number of customer offers in the marketplace and the complexity of those offers. Complexity is influenced by a number of factors including the barriers that exist to customer participation, the number of partnerships involved (e.g., market channels, FortisBC, installation contractors, municipalities), and the number of technologies supported. Developing and managing offers requires gathering and assessing customer and industry feedback, design work, budgeting, partnership management, internal and external training, promotion as well as

monitoring and reporting. The 30 FTEs in this department are divided as follows:

- 17 FTEs design and manage approximately 20 DSM offers targeting BC Hydro's Residential, Commercial and Municipal customers. Many of the offers in the marketplace have an increased level of complexity relative to historical program offers. For example, BC Hydro's new Non-Integrated Areas offer, discussed in Chapter 10, section 10.2.4, has unique geographical and market barriers, relative to similar offers in the integrated area;
- Nine FTEs focus on cross-sectoral initiatives, including the Sustainable Communities offer, New Construction Builder support, Indigenous Communities Policy support and pilot activity on localized DSM, demand response and connected homes and buildings. These FTEs also support for the development of new codes and standards, including B.C.'s Building Step Code;
- Three FTEs deliver marketing analytics, which provides customer targeting, marketing campaign and trial assessments, and reports and dashboards to help manage DSM offers. In fiscal 2018, this team completed 187 data analytics projects to inform BC Hydro's DSM program offers; and
- One FTE represents the manager of the department;

- 19 FTEs in the Industrial Marketing (Program Management) department as follows:
  - 11 FTEs, predominantly program managers and engineers, are responsible for the design and management of DSM offers targeting BC Hydro's Industrial customers. Similar to the Marketing (Program Management) group, staffing requirements are determined by the number and complexity of offers in the marketplace. Currently, approximately 10 industrial offers are being managed by this team, including incentive and energy study offers for

transmission and distribution customers, strategic energy management offers and pilot activity on demand response and localized DSM;

- Seven FTEs manage the training, quality control and accreditation of 900 Alliance members across all customer segments. These members are qualified external service providers who supply goods and services to all of our customers. Staffing levels on this team have remained flat since fiscal 2017, while many drivers of workload have increased. For example, there has been an increase in new and renewal member applications and an increase in referral requests from customers looking for qualified consultants and contractors to provide energy management services; and
- One FTE represents the manager of the department;

- 38 FTEs in the Operations, Engineering and Quality Management department. Staffing levels in this department are driven by the number of customer applications submitted each year. These FTEs can be categorized as follows:
  - Twenty FTEs on the operations team process 1,100 to 1,200 commercial and industrial applications and 32,000 to 48,000 residential applications each year. This includes applications for feasibility studies, plant-wide audits, energy managers, incentive projects and program enabled projects. Processing applications triggers further work such as carrying out credit reviews, reviewing and approving incentive payments and handling escalations. This work also includes quality management functions, such as developing and implementing business processes, implementing controls for business operations, verifying compliance with requirements, and oversight of the information technology systems used for application processing, tracking and reporting;
  - 17 FTEs on the engineering team, covering a range of specialized areas (e.g., lighting, HVAC, Pulp and Paper, Mining, etc.), perform technical reviews of custom projects to validate the viability of the projects and to

estimate energy savings and project costs. Engineering staff also advise Marketing and Industrial Marketing on the development of offers, and provide technical support to customers on their proposed DSM projects; and

- One FTE represents the manager of the department;

- 19 FTEs in the Evaluation, Measurement and Verification department as follows:
  - Nine FTEs on the Evaluation team. Staffing levels on this team are driven by the number of DSM programs and initiatives in the market and by BC Hydro's DSM evaluation criteria. Evaluation reports produce final estimates of the energy impacts of DSM programs, rate structures and codes and standards, and identify opportunities for improvement. The number of these reports has remained similar at four to six per year since fiscal 2016. In addition to completing evaluation reports, this team also conducts between 16 and 19 data collection activities each year. Examples of these activities include Residential and Commercial End-Use Surveys;
  - Nine FTEs on the Measurement and Verification team. While the Evaluation team estimates energy savings at a program level, the Measurement and Verification team estimates energy savings at a project level. This information is used to adjust incentive levels for specific projects, inform individual Customer Baselines claims for rates related projects, inform program evaluations, and provide feedback to customers and BC Hydro staff on project performance. Staffing levels on this team are driven by the volume of projects implemented by commercial and industrial customers and by BC Hydro's measurement and verification criteria. The work resulting from these drivers involves on-site visits, installation of metering equipment on electrically energized equipment at customer sites and data analysis. The team produces between 70 and 100 measurement and verification reports each year, which document final estimates of the energy impacts of

customer projects. This team also provides between 50 to 60 Customer Baseline reviews each year, depending on the number of transmission customers submitting a Customer Baseline claim. Lastly, the team completes between 40 to 60 measurement and verification plans each year, depending on the number of customers submitting project applications; and

- One FTE represents the manager of the department.

5F.6.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5F-10 Conservation and Energy Management KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.6 L3	0.6	0.6	0.6	0.5	0.6	0.6	0.6	0.6
2	FTEs	16.0 L37	114	110	112	112	112	116	116	116

Operating costs and FTEs for the Conservation and Energy Management KBU are planned to remain constant from fiscal 2019 forecast to fiscal 2020 and fiscal 2021 plan.

As discussed above, nearly all labour costs for this KBU are classified as deferred operating expenditures and are charged to the DSM Regulatory Account. Deferred operating expenditures in fiscal 2020 and fiscal 2021 reflect Standard Labour Rate increases.

5F.7 Power Acquisitions and Contract Management KBU

5F.7.1 Responsibilities

The Power Acquisitions and Contract Management KBU is responsible for managing and administering BC Hydro’s IPP resource portfolio and contracts, for both the integrated system and the Non-Integrated Area. These contracts represent a cost commitment of over $50 billion for contracts that extend as long as 60 years. In addition, this KBU provides specialized negotiation expertise for other potential commercial opportunities (e.g., the 2017 Waneta Transaction and the water use agreements with the Greater Vancouver Water District).

More specifically, the responsibilities undertaken by this KBU include:

- Managing and resolving contractual issues relating to approximately 130 existing Electricity Purchase Agreements (**EPAs**);
- Verifying and processing over 140 EPA invoices per month to confirm compliance with contractual terms;
- Forecasting IPP portfolio energy deliveries and costs on a monthly basis;
- Evaluating potential resource acquisitions such as the Biomass Energy Program which is discussed further in Chapter 4, section 4.3.2;
- Negotiating bilateral agreements for EPA renewals and new EPAs that are related to commitments to First Nations;
- Managing remaining applications through the indefinite suspension of the Standing Offer Program, which is discussed in Chapter 4, section 4.3.2;
- Developing, managing, and administering the Net Metering Program; and
- Conducting specialized commercial negotiations with First Nations, IPPs, industrial customers and other utilities.

Since the Previous Application, the focus of this KBU has shifted from pursuing new EPAs to bilateral negotiations related to EPA renewals.

5F.7.2 Overview of Operating Costs and FTEs

Table 5F-11 Power Acquisitions and Contract Management KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Power Acquisitions & Contract Management	4.4	0.0	0.3	0.0	0.0	0.0	0.0	**4.8**	27
2	**Total (Sch 5.6 L4, Sch 16.0 L38)**	**4.4**	**0.0**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	**4.8**	**27**

The budget for the Power Acquisitions and Contract Management is primarily made up of labour costs, totalling $4.4 million.

In addition, the budget includes approximately $0.3 million per year in external services expenditures which includes consultant fees related to permitting, technical and other due diligence assessments of IPPs as well as invoice verification system costs.

The number of EPAs in the IPP portfolio doubled from 66 to 131 between fiscal 2010 and 2016, and the annual payments related to EPAs increased from approximately $0.6 billion to $1.3 billion. These contracts are complex, with a range of technologies and contractual terms, stemming from different call processes, programs and bilateral negotiations, such as renewals and new EPAs related to Impact Benefits Agreements.

The total FTEs in this KBU increased from 23 to 27 from fiscal 2016 to fiscal 2019. These additional FTEs were required to support the increased volume, diversity and complexity of EPAs in commercial operation, and to respond to a fiscal 2017 internal audit which emphasized the need for adequate resources to provide effective financial oversight of IPP cost commitments. These FTEs were funded by reducing the use of contractor resources through the Workforce Optimization Program, which is discussed further in Chapter 5, section 5.6.1.

In recent years, the number of bilateral negotiations managed by this KBU has increased as EPA contracts expire. The level of resources and time required for bilateral negotiations is often more significant than the requirements to design standardized calls for power.

During the test period, major initiatives undertaken by this KBU will include:

- Managing up to 15 expiring EPAs. Projects in this category are diverse ranging from small hydro projects from the 1989 call to the Biomass Energy Program to projects in the Non-Integrated Area;

- Implementing the Biomass Energy Program;
- Conducting other commercial negotiations and project assessments, such as those related to Impact Benefit Agreements with First Nations;
- Managing the commercial elements of BC Hydro's contracts in the Non-Integrated Area, which are expected to increase during the test period due to the Government of B.C.'s CleanBC Remote Community Clean Energy Strategy which aims to reduce diesel-powered electricity generating stations in remote communities;
- Administering the Net Metering Program which has increased from 925 participants in fiscal 2017 to 1800 participants in fiscal 2019, and is expected to continue to grow;
- Providing content and consultation for an application to update the Net Metering Program;
- Advancing new Standing Offer Program EPAs that are related to commitments to First Nations; and
- Managing remaining applications through the indefinite suspension of the Standing Offer Program, responding to inquiries from developers and supporting the Ministry of Energy, Mines and Petroleum Resources' engagement with First Nations regarding the extent to which the indefinite suspension may affect their interests.

5F.7.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5F-12 Power Acquisitions and Contract Management KBU Operating Costs and FTEs

	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
		1	2	3	4	5	6	7	8
Operating Costs ($ million)	5.6 L4	4.6	4.6	4.7	4.9	4.8	4.8	4.7	4.7
FTEs	16.0 L38	23	26	23	28	23	27	26	26

Operating costs are decreasing by approximately $0.1 million from fiscal 2019 forecast to fiscal 2020 plan due to the transfer of one FTE to the Economic Development Team in the Customer Service KBU. The cost decrease related to this transfer is partially offset by Standard Labour Rate increases. Operating costs and FTEs from fiscal 2020 plan to fiscal 2021 plan are relatively constant.

5F.8 Communications and Community Engagement KBU

5F.8.1 Responsibilities

The Communications and Community Engagement KBU is responsible for the development and delivery of communications to key audiences, including customers, stakeholders, the Government of B.C., local governments, employees and the media. This includes information about BC Hydro's operations, capital projects, safety programs, conservation programs, emergency preparedness and customer service.

Since the Previous Application, the Policy and Reporting KBU has been transferred to the Communications and Community Engagement KBU. In addition, as a result of the Accenture repatriation, the Graphic Design Services team is now part of the Communications and Community Engagement KBU.

The Communications and Community Engagement KBU includes a number of functions not traditionally housed within a typical Communications department. In addition to marketing and media relations, and employee communications functions, the department includes community relations, policy and research. Consolidation of these teams under one umbrella allows BC Hydro to manage communication activities in an effective and collaborative manner. Since fiscal 2017, the Communications and Community Engagement KBU has also reduced its reliance on outside contractors to allow increasingly important digital communication to be completed in-house and at lower cost.

The Communications and Community Engagement KBU consists of the following five departments:

- Marketing Communications Department;
- Communities and Capital Projects Department;
- Media Relations and Issues Management Department;
- Policy, Research and Strategic Communications Department; and
- Employee Communications Department.

5F.8.1.1. Marketing Communications Department

The Marketing Communications department provides both proactive and responsive communications to customers and stakeholders. The department supports a range of communications activities to build public awareness and understanding of energy conservation and management, customer service offerings, electrical safety and power outage preparedness. In addition, in the event of emergencies, the department supports incident response and restoration efforts through 24/7 communication and outreach to customers. More and more, our customers expect BC Hydro to be online to share information, meet their service needs and hear about programs. As a result, marketing strategies, campaigns, programs and content are centred on creating digital experiences.

As the media landscape shifts to digital communication, we see the value of bringing digital creative production services in-house. With this approach, we can be more agile as the landscape evolves while spending less than it would cost to hire consultants.

The Marketing Communications department is comprised of three teams:

- Digital Communications;
- Customer Campaigns; and

- Brand Strategy.

The Digital Communications team leads BC Hydro's digital strategy and 24/7 social media strategy across all digital channels including bchydro.com, powersmart.ca, Hydroweb (employees' intranet site), customer email, e-newsletters and social platforms, developing rich content to engage customers, build followers and stand out in a crowded digital marketplace to convey important messages to customers. The team monitors social media channels closely for a range of topics related to customer feedback and issues. The team also plans campaigns to reach customers online at key points throughout the year and support customers' needs for information. An emphasis is placed on mobile communications, as 48 per cent of the nearly 18 million visits to bchydro.com each year are through mobile devices and these numbers continue to grow. The shift to digital communications also creates a need for data analytics to evaluate the effectiveness of our efforts and adapt accordingly.

The Customer Campaigns team leads the ongoing development of an annual integrated campaign strategy to provide information to customers. By using a combination of paid (advertising), owned (digital and face-to-face) and earned (media) communications strategies, the team designs campaigns that reach customers when they are most receptive to the information. Safety campaigns in the winter and late spring raise awareness of the hazards of electricity; conservation campaigns in the fall and spring encourage customers to save energy through actions in their homes and businesses; and customer service campaigns raise awareness of new offerings and updated services. The team develops strategies and messages to target a range of demographics and in a number of languages.

The Brand Strategy team leads BC Hydro's face-to-face outreach programs including a community marketing team and a K-12 Schools Program. Engaging with customers face-to-face allows for conversations and dialogue that spark an interest in energy, conservation, customer service and safety, leading to customers taking action at home, in businesses and in schools. The team is also responsible for ensuring the BC Hydro brand is applied in a consistent and effective manner which is key to effective communications in an increasingly cluttered media environment. With the repatriation of services provided by Accenture, this team is also responsible for Creative Services, which supports brand management and standards as well as graphics services and support to KBUs across BC Hydro.

5F.8.1.2. Communities and Capital Projects Department

The Communities and Capital Projects department liaises with stakeholders across B.C. to facilitate approvals for operational imperatives, regional programs and capital projects. The department works to help resolve escalated issues between BC Hydro and its customers and helps to manage BC Hydro's relationships in communities where there is a concentration of assets and operational activities.

The Communities and Capital Projects department is comprised of four teams:

- Community Relations;
- Capital Projects Communications;
- Community Investment and Retiree Programs; and
- Visitor Centres.

The Community Relations team builds relationships with local governments in over 160 communities, including mayors, councillors, regional district officials and community leaders. Community Relations is the primary contact for the constituency offices for all 85 Members of the Legislative Assembly.

This team also provides communications support and coordinates with stakeholders on a range of matters including vegetation management, escalated customer issues, planned power outages, local construction projects, and the operations of our generation facilities. During significant emergency events such as storms and fires, Community Relations shares information with and acts as a conduit for elected officials and the community to support a two-way dialogue.

The Capital Projects Communications team works closely with community stakeholders, leading consultation and communications work on BC Hydro's capital projects. The team gathers local feedback from stakeholders to inform the decision-making process on projects. By conducting early and ongoing consultation and communications during all phases of a capital project, risks of delay or cost increases can be mitigated.

The Community Investment and Retiree Programs team administers the award of scholarships to select B.C. students, support non-profit groups and registered charities through grants, and funds organizations and initiatives through sponsorships that support BC Hydro's business objectives. This team also coordinates an annual charity workplace campaign to help BC Hydro employees give back to their community and supports BC Hydro retirees through the Power Pioneers Program.

The Visitor Centres team operates the Revelstoke Dam Visitor Centre, the W.A.C. Bennett Dam Visitor Centre in Hudson's Hope and the Powerhouse at Stave Falls Visitor Centre in Mission. This work builds understanding of BC Hydro operations in communities. Visitor Centre staff provide information about our historic and current operations in the region as well as education on energy conservation and electrical safety.

5F.8.1.3. Media Relations and Issues Management Department

This department is available 24 hours a day, seven days a week to provide information to the public through major and local media about BC Hydro's business and operations. This includes updates on damage caused by major storms and other emergency events, electrical safety information and tips for customers on how to conserve electricity. To build public awareness and understanding, the department also provides timely information to the media about various customer programs and capital projects that impact customers in communities across the province.

This department also provides communications training to dozens of senior leaders and subject matter experts in BC Hydro each year so that they are prepared to speak on behalf of BC Hydro when required.

Lastly, this department works with the Government of B.C. to keep them informed about our business and provide up-to-date information on key topics. This proactive approach mitigates the amount of time spent on escalated or emerging issues.

5F.8.1.4. Policy, Research and Strategic Communications Department

This department provides policy coordination and advice to support BC Hydro’s priorities as well as the policy objectives of the Government of B.C. The department is comprised of the Policy team and the Corporate and Marketing Research team.

The Policy team works with the Ministry of Energy, Mines and Petroleum Resources to deliver on key reporting and legislated requirements, including the Budget Estimates Debate, the Annual Service Plan Report and the Service Plan. This involves providing information to the public about BC Hydro’s performance, corporate governance and strategic priorities. The team also provides strategic advice and communications support, such as developing briefing materials with KBUs across BC Hydro, in response to emerging public policy developments. The Strategic Communications Plan is also prepared by the team to facilitate collaborative communications work across teams within the KBU.

The Corporate and Market Research team supports a number of BC Hydro’s KBUs, most notably the Conservation and Energy Management KBU and the Customer Service KBU. The team is responsible for assessing the effectiveness and awareness of various initiatives and programs as well as tracking customer satisfaction, which is a BC Hydro Service Plan performance measure.

5F.8.1.5. Employee Communications Department

The Employee Communications department provides employees with the information they need to enhance their work and support BC Hydro's strategic and operational initiatives. As a large number of BC Hydro employees work in the field, at BC Hydro facilities and district offices throughout the province, the department uses a variety of communications platforms to engage employees and meet a growing demand for information. These platforms include an employee intranet, newsletters, executive messages and company-wide conference calls. The department also provides members of BC Hydro's Executive Team with strategic communications support to promote employee engagement and enhance the visibility of senior leadership.

5F.8.2 Overview of Operating Costs and FTEs

Table 5F-13 Communications and Community Engagement KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Chief Communications Officer	0.4	0.0	0.0	0.0	0.0	0.0	0.0	**0.4**	2
2	Marketing Communications	2.3	0.0	3.0	0.0	0.2	0.0	0.0	**5.5**	48
3	Communities and Capital Projects	3.1	0.0	1.4	0.1	0.1	0.0	0.0	**4.7**	38
4	Media Relations and Issue Management	0.5	0.0	0.0	0.0	0.0	0.0	0.0	**0.6**	5
5	Policy, Research and Strategic Comm	0.7	0.0	0.4	0.0	0.0	0.0	0.0	**1.1**	6
6	Employee Communications	1.3	0.0	0.1	0.0	0.0	0.0	0.0	**1.3**	9
7	**Total (Sch 5.6 L5, Sch 16.0 L39)**	**8.3**	**0.0**	**4.9**	**0.1**	**0.3**	**0.0**	**0.0**	**13.6**	**107**

5F.8.2.1. Chief Communications Officer Department

This department's budget consists of labour for two FTEs - the Chief Communications Officer and an administrative assistant.

5F.8.2.2. Marketing Communications Department

This department consists of 48 FTEs. Many of these FTEs support BC Hydro's DSM programs and initiatives. Accordingly, 58 per cent of the costs associated with these FTEs are treated as deferred expenditures and are charged to the DSM Regulatory Account. These FTEs are divided into the following teams:

- Two FTEs represent the Director of Marketing Communications and an administrative assistant;
- 15 FTEs on the Digital Communications team. This team responds to an average of 10,000 social media posts from customers each year, including significant activity during storms and other major emergencies and operational events. The team also delivers 12 million transactional emails annually including email bill delivery, collections notices and notifications related to customer accounts. Lastly, this team manages the employee intranet which receives approximately 1.4 million visits each year. To support this work, the Digital Communications operating budget includes $0.8 million for advertising, software licenses, specialized application support, content development, video production, and other incidental expenses;
- Six FTEs on the Customer Campaigns team. This team delivers more than 20 conservation, safety and other customer information campaigns each year. Examples of other customer information campaigns include BC Hydro's paperless adoption campaign, which supports a reduction in postage, paper and printing costs as described in section 5F.5.2.1. To support this work, the Customer Campaigns operating budget includes $0.7 million for advertising. The fiscal 2019 forecast amount also includes one-time funding of $1.2 million for customer campaigns to promote affordability and conservation measures. This one-time funding is not included in the fiscal 2020 plan or fiscal 2021 plan amounts; and
- 25 FTEs on the Brand Strategy team, including:
  - Two FTEs supporting BC Hydro's Schools and Education Program which provides energy conservation and safety information to approximately 10,000 students each year. The program has substantially increased its reach with the launch of a new online platform which was completed with no increase in budget. The program maintains a teacher mailing list with

approximately 10,000 subscribers, 3,800 teacher user accounts and a web site which received 25,800 visits during the 2017/2018 school year (up from 8,800 visitors in 2016/2017). The program's operating budget includes $0.2 million for advertising, supplies, application support and education consultants to support electrical safety awareness in schools;

- Eight FTEs on the Creative Services team responds to requests from across BC Hydro to create visual content (print, digital and video) to support consistent communication and customer understanding. From fiscal 2016 to fiscal 2018, this team completed approximately 2,200 requests each year. Depending on complexity, the average number of hours spent on each request ranges from five to 12 hours. The Creative Services operating budget includes $0.1 million non-labour for specialized software, application support and supplies;
- 13 FTEs on the Community Outreach team. This includes three FTEs on the core planning team, eight FTEs are a Team Lead, year-round outreach and retail representatives and two FTEs represent casual employees who support the spring and fall awareness campaigns for approximately 10 weeks per year. This team visits 80 communities across the province and engages with over 50,000 customers a year both in-person and through digital channels in conversations about energy conservation and management as well as customer service priorities; and
- The remaining two FTEs represent the department manager and a brand standards lead who is responsible for the development, maintenance and enforcement of all brand assets for employees and suppliers.

5F.8.2.3. Communities and Capital Projects Department

The 38 FTEs in this department are divided into the following teams:

- 14 FTEs on the Community Relations team. Approximately 15 per cent of the cost for these FTEs are charged to capital projects that are supported by BC Hydro's community relations managers;
- Nine FTEs on the Capital Projects Communications team. The FTEs in this department charge approximately 80 per cent of their time to the capital projects they are supporting. In fiscal 2019, the team supported over 180 capital projects;
- Four FTEs on the Community Investment and Retirees Program team. The Community Investment operating budget includes $0.6 million for donations and sponsorships and $0.2 million for advertising. In fiscal 2016, BC Hydro revamped its sponsorships program, reducing the overall funding by 50 per cent and targeting sponsorships to areas that support BC Hydro's operations, such as building a skilled workforce, supporting safe and smart energy use and fostering strong relationships in the communities where our operations have the most impact; and
- 11 FTEs on the Visitor Centres team. In calendar 2019, there were more than 41,000 visitors to BC Hydro's Visitor Centres. The visitor centre's operating budget includes $0.5 million for materials and supplies, advertising (signage, displays, ads), security and janitorial services and travel costs. Costs related to BC Hydro's visitor centres are partially offset by revenue from entrance fees.

5F.8.2.4. Media Relations and Issues Management Department

The majority of this department's budget is related to labour for five FTEs.

The media landscape has changed. Traditional media is shrinking and more outlets are moving online. However, the demand for news is higher than ever and has become a 24/7 business that takes no breaks. Stories will not wait for BC Hydro's comment, which is why BC Hydro's media relations team needs to be available 24 hours a day, seven delays a week.

In addition, as storms and extreme weather have become more frequent over the past five years, so have the after-hours demands on the team. In fiscal 2018, BC Hydro responded to approximately 1,000 media requests.

This department also prepares more than 100 earned media pieces each year ranging from news releases and information bulletins to operational updates and reports to provide customers with important information when and where they need it. Earned media efforts avoid the need to purchase additional advertising spots. Between April and December 2018, BC Hydro's earned media efforts generated over 1,500 stories, with estimated 100 million media impressions.

5F.8.2.5. Policy, Research and Strategic Communications Department

The majority of this department's budget is related to labour for six FTEs.

- Three FTEs on the Policy team provide coordinated advice and information to Government so that the impacts of various policy decisions on ratepayers are understood and considered. In calendar year 2018, this team responded to over 60 requests from the Ministry of Energy, Mines and Petroleum Resources. Between fiscal 2016 and fiscal 2018, the team also prepared an average of 75 briefing notes each year for the Government of B.C.; and
- Three FTEs on the Research team support KBUs across BC Hydro by conducting surveys and focus groups. Feedback gained through this work provides valuable insights so that BC Hydro can better serve its customers and employees. The Research team uses an in-house polling tool called Your Power Poll to survey a group of 4,000 customers, at a lower cost than using an outside vendor. BC Hydro completes an average of 60 surveys through Your Power Poll each year at a cost of approximately $0.08 million. BC Hydro estimates that using an outside vendor for these surveys would cost approximately $0.4 million per year. The Research team also uses Insite Software to conduct customer panel research. BC Hydro completes an average of 12 projects through this software each year at a cost of approximately

$8,000. BC Hydro estimates that using an outside vendor for these projects would cost approximately $0.08 million per year.

The department's operating budget includes $0.4 million for specialized software and application support and research services such as customer satisfaction surveys.

5F.8.2.6. Employee Communications Department

The majority of this department's budget is related to labour for nine FTEs. These FTEs support BC Hydro's KBUs and provide overall and targeted communications to BC Hydro's 6,500 employees, including approximately 2,000 field and stations based workers with limited computer access.

There is a strong correlation between engaged and committed employees and employee retention, productivity and organizational effectiveness. In a time of change in our industry and our company, effective, directed and clear employee communication is essential to keeping employees informed and connected to their work.

Activities carried out by these FTEs include:

- The development of over 140 internal communications plans each year;
- Drafting over 100 Executive Team messages per year, researching and preparing responses to hundreds of employee e-mails and developing speaking notes and supporting visuals for internal and external presentations;
- Developing and executing between 10 to 15 employee campaigns per year on monthly priorities as well as safety and workplace initiatives;
- Executing four safety conference calls per year as well as additional employee calls to respond to operational and emerging issues; and

- Managing six internal communications channels (an employee intranet, executive communications, 75 office and field TV screens, poster boards, all-employee calls and lobby displays).

The department's operating budget includes $0.1 million for promotional materials and supplies.

5F.8.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5F-14 Communications and Community Engagement KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.6 L5	12.8	12.4	12.6	13.7	12.7	13.6	12.9	13.0
2	FTEs	16.0 L39	86	94	86	95	86	107	107	107

Operating costs are decreasing by approximately $0.7 million from fiscal 2019 forecast to fiscal 2020 plan due to the removal of one-time funding of $1.2 million for customer advertising campaigns focused on affordability and conservation, partially offset by Standard Labour Rate increases of approximately $0.4 million.

Operating costs are increasing by approximately $0.1 million from fiscal 2020 plan to fiscal 2021 plan due to Standard Labour Rate increases.

FTEs are planned to remain constant during the test period. The increase in FTEs from fiscal 2019 RRA to fiscal 2019 forecast was primarily driven by the Workforce Optimization program, described in Chapter 5, section 5.6.1 and the Accenture Repatriation, described in Chapter 5, section 5.6.2.

5F.9 Regulatory and Rates KBU

5F.9.1 Responsibilities

This KBU is responsible for providing regulatory advice to KBUs across BC Hydro, developing regulatory strategies and managing applications and initiatives through the regulatory process. BC Hydro believes that an open and transparent regulatory process leads to better decisions and improved outcomes for our customers. This KBU supports this approach, acting as the main interface between the Commission and BC Hydro and managing relationships with interveners during and outside regulatory proceedings.

There have been no material changes to the nature of the responsibilities of the Regulatory and Rates KBU since the Previous Application.

This KBU is organized into the following four teams:

- Capital Projects and Resource Planning;
- Rates and Finance;
- Tariffs; and
- Compliance and Filings.

The Capital Projects and Resource Planning team is responsible for providing strategic planning, regulatory advice and support to KBUs regarding capital projects, EPAs, Mandatory Reliability Standards, and resource planning. This includes leading regulatory applications and related compliance filings and providing monthly customer outage reporting to the Commission.

Capital Planning and Resource Planning team also includes the Reliability Compliance group which is responsible for BC Hydro's Mandatory Reliability Standards Program. The Mandatory Reliability Standards, which are approved by the BCUC, define requirements for planning, maintaining and operating the Bulk Electric System such as transmission system planning and modelling, protection system maintenance, critical infrastructure protection and real-time operations.

The Mandatory Reliability Standards Program governs the oversight activities associated with these requirements including the development of recommendations to the BCUC for adopting new or revised Mandatory Reliability Standards in B.C. These activities include:

- The development of annual Assessment Reports for filing with the BCUC;
- Education about and implementation of the Mandatory Reliability Standards with impacted KBUs; and
- Monitoring of Mandatory Reliability Standards compliance including annual self-certifications and on-site audits.

The Rates and Finance team is responsible for providing strategic planning, regulatory advice and support to KBUs regarding accounting, financial and revenue requirement regulatory matters. This includes leading BC Hydro's revenue requirements applications to the Commission, as well as finance-related compliance filings.

The Tariffs team is responsible for residential, general service, transmission service and Open Access Transmission Tariff (**OATT**) rates; administering the Standards of Conduct program[282]; and managing permits and reporting related to BC Hydro's international power lines. To support these responsibilities, the department carries out the following activities:

- Providing regulatory advice and research related to tariffs and rate design;
- Responding to external and internal tariff and rate queries;
- Managing OATT applications, administration and technical issues; and
- Providing support and guidance for customer complaints and compliance filings.

[282] The Standards of Conduct Program is an internal program developed by BC Hydro to support compliance requirements for the management of non-public transmission function information in the provision of wholesale electricity sales.

The Compliance and Filings team is responsible for coordinating and implementing activities to meet regulatory requirements. This includes:

- Preparation, review, quality control and tracking of regulatory materials;
- Research and training to support the development of applications; and
- Coordination and preparation of public workshops and hearings.

5F.9.2 Overview of Operating Costs and FTEs

Table 5F-15 Regulatory and Rates KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Regulatory and Rates	4.8	0.0	1.4	0.0	0.0	0.0	0.0	**6.2**	28
2	**Total (Sch 5.6 L6, Sch 16.0 L40)**	**4.8**	**0.0**	**1.4**	**0.0**	**0.0**	**0.0**	**0.0**	**6.2**	**28**

Approximately 77 per cent of the Regulatory and Rates KBU budget is related to labour. This represents 28 FTEs as follows:

- A Chief Regulatory Officer and an Administrative Assistant;
- One Manager and two Regulatory Specialists in Capital Projects and Resource Planning;
- One Manager and four Reliability Compliance Specialists in Mandatory Reliability Standards;
- One Manager and three Regulatory Specialists in Rates and Finance;
- One Manager and nine Regulatory Specialists in Tariffs; and
- One Manager and three Regulatory Coordinators in Compliance and Filings.

From fiscal 2016 to fiscal 2018, BC Hydro submitted an average of approximately 300 filings to the BCUC each year. This equates to a ratio of approximately 14 filings each year for each manager or specialist in the KBU. The complexity of these filings ranges from recurring compliance reports with no or minimal process, to standard applications which may have an information request and argument phase, to major applications which may span multiple years with multiple rounds of information requests, intervener evidence, oral hearings and arguments. All of these filings, small to large, require varying degrees of regulatory oversight and expertise from employees in this KBU. BC Hydro expects the number and complexity of filings to the BCUC to increase going forward as a result of the Government of B.C.'s Comprehensive Review, which has enhanced the BCUC's regulatory oversight of BC Hydro.

The remaining 23 per cent of the Regulatory and Rates KBU budget consists of the following material costs in Services – Other:

- BCUC Hearing Room Rental Fee;
- BCUC Fees;
- Participant Assistance / Cost Awards awarded by the BCUC to facilitate intervener participation in regulatory proceedings; and
- Consultant resources.

The BCUC Hearing Room Rental Fee is relatively constant and budgeted at $0.2 million annually. The remaining costs are driven by the number, type, complexity and length of regulatory proceedings in a given year and can vary.

- BCUC fees are budgeted at $0.3 million but ranged from approximately $0.2 million to $0.4 million during the fiscal 2016 to fiscal 2018 period. These fees are directly related to the number, length and complexity of regulatory proceedings;
- Participant Assistance / Cost Awards are budgeted at $0.4 million but ranged from approximately $0.3 million to $0.9 million during the fiscal 2016 to fiscal 2018 period. These amounts are also directly related to the number and complexity of regulatory proceedings; and

- Consultant resources are retained to provide expertise in specialized subject areas during regulatory proceedings. They are budgeted at approximately $0.4 million. We expect this budget to be fully utilized going forward as a result of the Government of B.C.'s Comprehensive Review, which has provided the BCUC with enhanced oversight of BC Hydro. Potential applications during the test period, which will require consultant resources, include a performance based regulation application, a cost of capital proceeding and the 2021 Integrated Resource Plan. This budget also covers specialized consultant resources to assist with Mandatory Reliability Standards audits.

5F.9.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5F-16 Regulatory and Rates KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.6 L6	6.0	5.8	6.1	5.4	6.2	6.2	6.3	6.4
2	FTEs	16.0 L40	28	23	27	26	27	28	28	28

Operating costs are increasing by approximately $0.1 million from fiscal 2019 forecast to fiscal 2020 plan and by approximately $0.1 million from fiscal 2020 plan to fiscal 2021 plan, due to Standard Labour Rate increases. FTEs are planned to remain constant.

5F.10 Ethics and Merit Office KBU

5F.10.1 Responsibilities

The Ethics and Merit KBU supports BC Hydro's efforts to provide a safe and respectful work environment, serving as a neutral party to support all BC Hydro employees. This KBU is led by the Ethics Officer and provides independent expert advice to employees, managers, contract managers and contractors promoting respect, dignity, integrity and fairness.

The responsibilities of this KBU have increased since the Previous Application as the Ethics and Merit Office is now also responsible for overseeing fair hiring and merit-based practices.

This KBU is responsible for BC Hydro's Code of Conduct, Contractor Standards for Ethical Conduct, Respectful Workplace, Ombudsperson and Merit Programs.

- The Code of Conduct program provides employees with access to expert advice on Code of Conduct related matters, including consistent and clear interpretation of its standards of business conduct as well as guidelines to mitigate and avoid conflicts of interest. The Contractor Standards for Ethical Conduct program provides these same services to BC Hydro's contractors;
- The Respectful Workplace Program is consistent with WorkSafe BC and Human Rights Code requirements. It provides a variety of services to employees and managers so that employees at BC Hydro are treated respectfully and work in a harassment-free environment;
- The Ombudsperson serves as an impartial intermediary between BC Hydro and its employees. This function has existed within BC Hydro since 1998 and acts as a neutral third party to assist employees with fairness concerns related to employment; and
- The Merit Program was introduced in July 2018 to improve employee trust in BC Hydro's hiring practices. The Ethics and Merit Office KBU conducts reviews so that the principle of fairness is consistently applied in the recruitment process. It provides a mechanism for employees to report hiring concerns for further investigation.

5F.10.2 Overview of Operating Costs and FTEs

Table 5F-17 Ethics and Merit Office KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Ethics and Merit Office	0.5	0.0	0.3	0.0	0.0	0.0	0.0	**0.8**	4
2	**Total (Sch 5.6 L7, Sch 16.0 L41)**	**0.5**	**0.0**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	0.8	**4**

The Ethics and Merit Office KBU budget primarily consists of labour for four FTEs including the Ethics Officer, Ethics Advisor, Merit Advisor and an administrative assistant.

From fiscal 2017 to fiscal 2018, demand for the services provided by this KBU increased significantly. Code of Conduct inquiries increased from 104 to 149 and Respectful Workplace cases increased from 52 to 92. These numbers reflect the ongoing promotion of this KBU's services and do not include the additional responsibility for the Merit Program.

This KBU's budget also includes $0.3 million in non-labour costs. This includes funding for a secure confidential reporting line managed by a third-party service provider for individuals who prefer to report an incident anonymously. It also includes funding to retain independent subject-matter experts as required to provide independent investigations or to meet peak caseload and training volumes.

5F.10.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5F-18 Ethics and Merit Office KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.6 L7	0.4	0.5	0.4	0.6	0.4	0.8	1.0	1.0
2	FTEs	16.0 L41	1	2	1	3	1	4	5	5

Operating costs are increasing by approximately $0.2 million from fiscal 2019 forecast to fiscal 2020 plan, primarily due to the addition of one FTE to respond to the increase in demand for this KBU's services. The costs related to this FTE are offset by a reduction in operating costs in the Human Resources KBU. Operating costs are relatively constant from fiscal 2020 plan to fiscal 2021 plan.

5F.11 Business Unit Support KBU

5F.11.1 Responsibilities

The People, Customer and Corporate Affairs Business Unit Support KBU holds the budget for the Office of the Executive Vice-President of People, Customer and Corporate Affairs.

5F.11.2 Overview of Operating Costs and FTEs

Table 5F-19 Business Unit Support KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	EVP, People, Customer and Corp Affair	0.7	0.0	0.1	0.0	0.0	0.0	0.0	**0.8**	3
2	**Total (Sch 5.6 L8, Sch 16.0 L43)**	**0.7**	**0.0**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.8**	**3**

5F.11.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5F-20 Business Unit Support KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.6 L8	0.7	0.8	0.8	0.7	0.8	0.8	0.8	0.8
2	FTEs	16.0 L43	3	3	3	3	3	3	3	3

Operating costs and FTEs are planned to remain relatively constant during the test period.

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Chapter 5G

Operating Costs

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5G.1 Introduction – Other

Chapter 5G provides and explains in detail the composition of, and rationale, for the operating costs of the Other category.

The Other category includes two KBUs: The Office of the General Counsel, which reports directly to the President and Chief Operating Officer and the Office of the President and Chief Operating Officer.

Also included in this Other category are FTEs and operating costs related to:

- **Site C Project:** FTEs for the Site C Project are increasing during the test period as the project staffs up to a full complement of resources for the peak construction period. The project has no operating expenditures as all Site C costs are charged to capital or the Site C Regulatory Account. These costs will not impact rates until the project's assets are placed into service;
- **Independent Power Producer Capital Leases:** Under IFRS 16, BC Hydro has one EPA that is accounted for as a capital lease during the test period. However, there are no planned operating costs associated with this lease during the test period;
- **Corporate Costs:** Corporate Costs is used to manage the flow of payroll, benefits and current service pension costs to the business through Standard Labour Rates. It also receives general expenses that are not specifically related to any single Business Group or KBU and are captured centrally;
- **Capitalized Costs:** This includes costs that are eligible for capitalization under IFRS IAS 16 Property, Plant and Equipment, which are recorded in operating expenses and allocated to capital projects using a capital overhead loading rate. This also includes a credit for IFRS ineligible capital overhead costs, which are being phased into operating costs over a 10-year period. This phase-in will be complete by the end of fiscal 2022; and

- **Post-Employment Benefit Costs:** This consists of current service costs and non-current service costs. Current service costs are included in the Standard Labour Rates and charged to current work (capital and operating). Therefore, these costs are reflected in the costs presented throughout this Application. Non-current service costs are comprised of plan income on pension plan assets and interest expense on post-employment benefit liabilities. While non-current service costs are included in finance charges, the discussion on non-current service costs is included in this chapter so that current and non-current service costs are discussed together in one section within this Application.

Chapter 5G is organized as follows:

- Section 5G.2 provides the operating costs and FTE information for the Other category as a whole;[1] and
- Sections 5G.3 to 5G.9 provide more detailed information on the costs within the Other category.[283]

5G.2 Fiscal 2020 and Fiscal 2021 Plan Operating Cost and FTE Summaries

The operating costs for the Other category are summarized in Table 5G-1 below.

Table 5G-1 Other Net Operating Costs

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Office of the General Counsel	5.7 L1	12.2	11.1	12.3	10.6	12.3	12.2	11.7	11.8
2	Office of the President and Chief Operating Officer	5.7 L2	0.9	1.0	1.0	0.8	1.0	0.8	0.9	0.9
3	Site C Project	5.7 L3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Independent Power Producers Capital Leases	5.7 L8	28.2	28.2	63.6	63.6	54.3	54.3	0.0	0.0
5	Corporate Costs	5.7 L4	17.2	13.1	18.4	28.4	19.7	38.9	13.0	13.0
6	Capitalized Costs	5.7 L5+L7	(180.2)	(179.0)	(158.6)	(158.6)	(136.9)	(137.6)	(115.8)	(93.8)
7	Total	5.7 L12	(121.7)	(125.6)	(63.4)	(55.2)	(49.6)	(31.4)	(90.2)	(68.1)

FTEs in the Other category are summarized in Figure 5G-1. Additional detail is provided in Table 5G-2 below.

283 Please note the amounts presented in the tables in these sections may not add due to rounding.

Figure 5G-1 Other FTEs (Fiscal 2020 Plan)

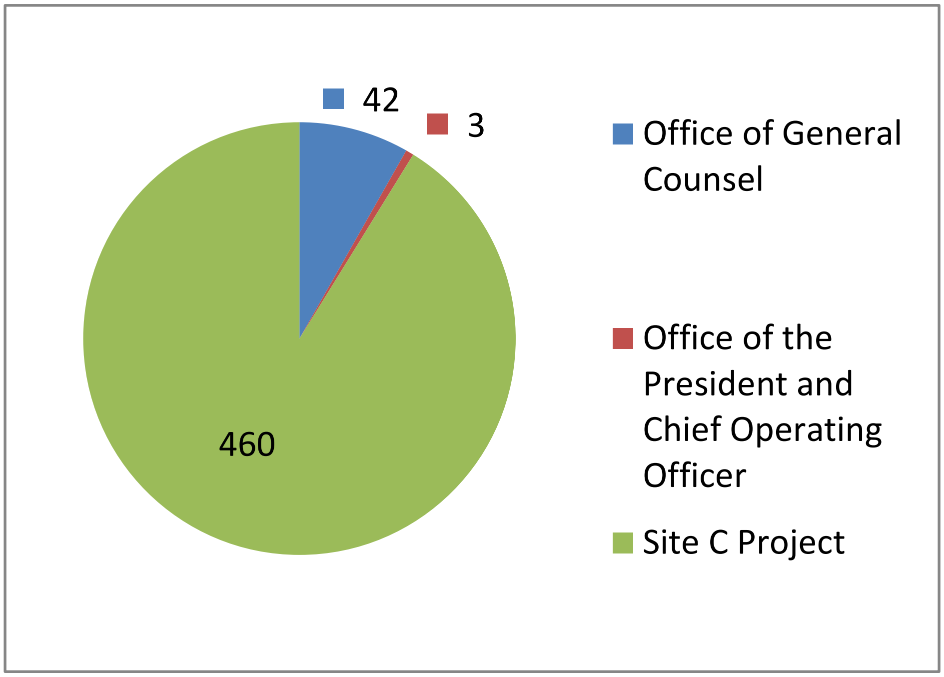

Table 5G-2 Other FTEs

	(FTEs)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Office of the General Counsel	16.0 L45	37	36	37	35	37	43	42	42
2	Office of the President and Chief Operating Officer	16.0 L46	4	4	4	3	4	3	3	3
3	Site C Project	16.0 L47	186	167	189	226	199	389	460	472
4	Independent Power Producer Capital Leases	16.0 L48	0	0	0	0	0	0	0	0
5	Corporate Costs	16.0 L49	0	0	0	0	0	0	0	0
6	Capitalized Costs	16.0 L50	0	0	0	0	0	0	0	0
7	Total	16.0 L51	227	208	231	264	241	434	505	516

Table 5G-3 below provides a continuity table which highlights changes to the Other category from the Previous Application. An overall discussion of these changes, at a company-wide level, is provided in Chapter 5, section 5.5.2. Further details are provided in the sections below.

Table 5G-3 Other Operating Costs Continuity Schedule [284]

	($ million)		F2020 Plan	F2021 Plan
1	F2019 Revenue Requirement Application Plan (Operations Support)		225.6	
2	Reorganization Impacts		(275.1)	
3	F2019 Revenue Requirement Application Plan (Other)		(49.6)	
4	Compliance Filing Adjustment (Schedule 5.0, line 8)		10.4	
5	Budget Transfers Between Business Groups		7.8	
6	Adjusted F2019 Revenue Requirement Application Forecast (Other) / carry forward plan (Schedule 5.7, line 12)	A	(31.4)	(90.2)
7	Independent Power Producer Capital Leases	B	(54.3)	-
8	IFRS Ineligible Capital Overhead	C	22.4	22.4
9	Current Year Budget Transfers Between Business Groups	D	(11.7)	
10	Test Period Savings			
11	Fleet capital overhead adjustment		(0.6)	(0.4)
12	Vacancy factor savings		(0.3)	
13	Miscellaneous savings		(0.2)	
14		E	(1.0)	(0.4)
15	Test Period Cost Increases (Decreases)			
16	Labour		(7.1)	0.1
17	Unallocated costs		(7.0)	
18		F	(14.1)	0.1
19	Test Period Net Increase/(Decrease)	G=E+G	(15.1)	(0.3)
20	Net Operating Costs (Schedule 5.7, line 12)	A+B+C +D+G	(90.2)	(68.1)

5G.3 Office of the General Counsel KBU

5G.3.1 Responsibilities

The Office of the General Counsel KBU reports directly to the President and Chief Operating Officer and provides guidance, expertise and oversight throughout BC Hydro on legal matters, corporate governance and freedom of information and

[284] Row 4 of Table 5G-3 relates to the current pension cost adjustment corresponding with BCUC Order No. G-47-18, Directive 18, which directed BC Hydro to use the discount rate in effect at the time the forecast was prepared to calculate current service costs;
Row 7 relates to the impact of the new accounting standard on leases, IFRS 16 which is further explained in section 5G.6 Independent Power Producers Capital Leases;
Row 8 represents IFRS ineligible capital overhead costs that are being phased in to operating costs over a 10-year period. Please refer to section 5G.8 for further information on IFRS ineligible capital overhead;
Row 16 represents the allocated labour costs to the Business Groups including the allocation of the compliance filing adjustment related to pension costs shown on row 4 above. The net labour cost increase for the Other category is $3.3 million (row 4 Compliance Filing Adjustment of $10.4 million plus row 16 labour of $(7.1) million).

privacy. There have been no material changes to the responsibilities of this KBU since the Previous Application.

The Office of the General Counsel KBU is comprised of the following three departments:

- Legal Services Department;
- Freedom of Information Coordinating Office Department; and
- Office of the Corporate Secretary Department.

5G.3.1.1. Legal Services Department

Legal Services is responsible for providing legal advice and support to the Board of Directors, the Executive Team, senior management, the Site C Project and all KBUs and departments across BC Hydro. BC Hydro operates in a complex and challenging legal environment, particularly given our significant presence across the province, increased regulatory compliance requirements and our status as both a regulated utility and a Crown Corporation.

5G.3.1.2. Freedom of Information Coordinating Office Department

The Freedom of Information Coordinating Office (**FOICO**) department is responsible for responding to, advising on, and addressing requests and issues related to access to information and privacy under the B.C. *Freedom of Information and Protection of Privacy Act* (**FOIPPA**) and other applicable legislation. Each year, the FOICO department responds to a large volume of direct requests as well as referrals from other agencies, working across BC Hydro to gather records and respond to requests within the time requirements in legislation. The work often involves detailed reviews of every record, which may involve hundreds or thousands of pages per request, to ensure responses are consistent with FOIPPA. This department oversees the implementation of BC Hydro's privacy policies and undertakes required privacy impact assessments for programs, projects and initiatives. In addition, the department provides compliance training and advice to managers and employees across BC Hydro.

5G.3.1.3. Office of the Corporate Secretary Department

The Office of the Corporate Secretary department organizes, facilitates and records all meetings of the Board of Directors and responds to internal and external inquiries concerning Board decisions. This department also supports the Board of Directors, the Executive Team, management and employees on corporate governance.

5G.3.2 Overview of Operating Costs and FTEs

Table 5G-4 Office of the General Counsel KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Legal Services	4.9	0.0	5.4	0.1	0.0	0.0	0.0	**10.4**	36
2	Freedom of Information	0.6	0.0	0.1	0.0	0.0	0.0	0.0	**0.7**	5
3	Office of the Corporate Secretary	0.3	0.0	0.8	0.0	0.0	0.0	0.0	**1.1**	2
4	**Total (Sch 5.7 L1, Sch 16.0 L45)**	**5.7**	**0.0**	**6.3**	**0.1**	**0.0**	**0.0**	**0.0**	**12.2**	**43**

The operating costs of the Office of the General Counsel KBU are largely comprised of labour costs and external legal fees. This KBU is also responsible for fees and expenses for BC Hydro's Board of Directors.

While the total operating costs of the KBU have remained stable from fiscal 2017 to fiscal 2019, the number of FTEs increased from 37 to 43. The additional FTEs were added through the Workforce Optimization Program, which is discussed in Chapter 5, section 5.6.1.

5G.3.2.1. Legal Services Department

The Legal Services department represents approximately 85 per cent of the General Counsel Office KBU operating costs. Legal services are provided by a team of in-house lawyers, supported by a paralegal and an administrative staff, as well as external lawyers. The department's costs are divided almost equally between labour and external legal support.

In-house lawyers are more cost-effective than external lawyers. For example, in fiscal 2019, the weighted average hourly cost of external counsel was more than three times the cost of our in-house counsel. Given this cost difference, as well as the benefits of having an in-house legal team knowledgeable about BC Hydro’s business, BC Hydro employs a team of in-house lawyers with expertise in a range of subjects.

The department retains external counsel for specialized legal expertise, large regulatory filings, litigation, large transactions and projects and to assist during periods of higher than expected work volumes. The department manages law firm retainers, including costs and work scope, so that external counsel are used appropriately and cost-effectively in conjunction with in-house lawyers.

5G.3.2.2. Freedom of Information Coordinating Office Department

The FOICO department represents approximately six per cent of the Office of the General Counsel KBU’s operating costs. The majority of costs in this department are related to labour. There are five FTEs in the department which consists of two information coordinators, one privacy specialist, one administrative assistant and one manager.

In fiscal 2017, this department was not able to respond to information requests within the statutory time requirements. Therefore, one FTE was added to help respond to the increased volume and backlog of requests. This backlog has now been addressed and to date in fiscal 2019, all FOIPPA information requests have been responded to within statutory time requirements. This additional FTE did not increase operating costs as the costs were fully offset by a reduction in consultant costs.

5G.3.2.3. Office of the Corporate Secretary Department

The Office of the Corporate Secretary department represents approximately nine per cent of the operating cost of the General Counsel Office KBU, including labour costs for two FTEs as well as fees and expenses for BC Hydro's Board of Directors. Labour costs are for the Corporate Secretary and an administrative assistant, who also supports the Executive Chair.

5G.3.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5G-5 Office of the General Counsel KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.7 L1	12.2	11.1	12.3	10.6	12.3	12.2	11.7	11.8
2	FTEs	16.0 L45	37	36	37	35	37	43	42	42

Operating costs are decreasing by approximately $0.5 million from fiscal 2019 forecast to fiscal 2020 plan due to vacancy factor savings and reductions to external services costs, which are partially offset by Standard Labour Rate increases. Operating costs are increasing by approximately $0.1 million from fiscal 2020 plan to fiscal 2021 plan due to Standard Labour Rate increases. FTEs are planned to remain constant.

5G.4 President and Chief Operating Officer KBU

5G.4.1 Responsibilities

The President and Chief Operating Officer KBU includes the President and Chief Operating Officer and two support staff.

5G.4.2 Overview of Operating Costs and FTEs

Table 5G-6 President and Chief Operating Officer KBU Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Office of the President and COO	0.7	0.0	0.1	0.0	0.0	0.0	0.0	**0.8**	3
2	**Total (Sch 5.7 L2, Sch 16.0 L46)**	**0.7**	**0.0**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.8**	**3**

5G.4.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

Table 5G-7 President and Chief Operating Officer KBU Operating Costs and FTEs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.7 L2	0.9	1.0	1.0	0.8	1.0	0.8	0.9	0.9
2	FTEs	16.0 L46	4	4	4	3	4	3	3	3

Operating costs are increasing slightly during the test period due to Standard Labour Rate increases.

5G.5 Site C Project

5G.5.1 Responsibilities

Given its size, complexity and duration, the Site C Project has been set up as its own group with a complement of resources to support all components of successful project execution. This project team reports directly to the President and Chief Operating Officer through the Executive Vice President of the Site C Project. Construction of the Site C Project began in July 2015 and is scheduled to complete in 2024. The project cost is $10.7 billion, consisting of an expected project budget of $10.0 billion and a project reserve subject to Treasury Board control of $0.7 billion. These costs will not impact rates until the project's assets are placed into service.

The Site C Project team works closely with other departments in BC Hydro to align with financial, legal, procurement, environmental, contract management, engineering, safety and project delivery policies and practices.

5G.5.2 Overview of Operating Costs and FTEs

Table 5G-8 Site C Project Fiscal 2019 Forecast Operating Costs and FTEs by Department

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Site C Project	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	389
2	**Total (Sch 5.7 L3, Sch 16.0 L47)**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**389**

The Site C Project has no operating expenditures as all costs are charged to capital or to the Site C Regulatory Account.

5G.5.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs and FTEs

**Table 5G-9 Site C Project
Operating Costs and FTEs**

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.7 L3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	FTEs	16.0 L47	186	167	189	226	199	389	460	472

FTEs for the Site C Project are planned to increase by 71 from fiscal 2019 forecast to fiscal 2020 plan and by 12 from fiscal 2020 plan to fiscal 2021 plan, as the project staffs up to a full complement of resources for the peak construction period.

5G.6 Independent Power Producer Capital Leases

5G.6.1 Description

BC Hydro has three Electricity Purchase Agreements (**EPAs**) that are accounted for as capital leases up until the end of fiscal 2019, under International Accounting Standard (IAS) 17 and IFRIC 4, the current accounting standards for Leases.

BC Hydro is required to review all EPAs to assess whether these agreements qualify as leases under IFRS 16, the new accounting standard for Leases that comes into effect starting in fiscal 2020. Please refer to Chapter 8, section 8.12.1 on the related accounting treatment on EPAs and Chapter 8, section 8.13.3 on the adoption of IFRS 16.

5G.6.2 Fiscal 2020 and Fiscal 2021 Plan Operating Costs

**Table 5G-10 Independent Power Producer Capital
Lease
Operating Costs**

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.7 L8	28.2	28.2	63.6	63.6	54.3	54.3	0.0	0.0

Due to the adoption of IFRS 16, starting in fiscal 2020, the operating costs for the three EPAs currently accounted for as capital leases will be recorded as Cost of Energy because these EPAs do not qualify as leases under IFRS 16. In addition, one EPA which was previously accounted for as Cost of Energy will be accounted for as a lease under IFRS 16; however, there are no planned operating costs associated with this lease for fiscal 2020 and fiscal 2021.

5G.7 Corporate Costs

5G.7.1 Description

Corporate Costs is used to manage the flow of payroll, benefits and current service pension costs to the business through Standard Labour Rates as described in Chapter 5, section 5.6.5.3. In addition, Corporate Costs receives general expenses that are not specifically related to any single Business Group or KBU and are captured centrally.

5G.7.2 Overview of Operating Costs and FTEs

Table 5G-11 Corporate Costs
Fiscal 2019 Forecast Operating Costs

	($ million)	Labour	Services - ABSU	Services - Other	Materials	Building & Equipment	Capitalized Overhead	External Recoveries	Total Operating	Total FTEs
1	Corporate Costs	8.9	0.0	29.8	0.0	0.2	0.0	0.0	**38.9**	-
2	**Total (Sch 5.7 L4, Sch 16.0 L49)**	**8.9**	**0.0**	**29.8**	**0.0**	**0.2**	**0.0**	**0.0**	**38.9**	**-**

The labour budget in Corporate Costs is typically zero as 100 per cent of the labour, benefit and current service pension costs planned are allocated out to the KBUs through Standard Labour Rates. In fiscal 2019, the budget of $8.9 million is primarily a result of the Previous Application compliance filing adjustment, pursuant to the BCUC's decision on the forecasting methodology to be used for current service pension costs. This budget has been included in the Standard Labour Rates for fiscal 2020 and fiscal 2021.

The fiscal 2019 forecast non-labour budget consists of the following services and building and equipment costs:

- $9.0 million for premiums on insurance policies including property, general liability, directors' and officers' liability, cyber liability and several other small, miscellaneous insurance policies;
- $4.0 million for annual cost recovery levies from the BCUC and the National Energy Board, as well as various other memberships;
- $15.0 million unallocated funds in fiscal 2019; and
- $1.9 million for trailing costs related to the Accenture repatriation in fiscal 2019. Further information on the Accenture repatriation is provided in Chapter 5, section 5.6.2.

The 2013 10 Year Rates Plan prescribed certain operating cost and rate increase targets, To manage unanticipated cost pressures within these targets, BC Hydro maintained a budget of unallocated funds. Starting in fiscal 2020, the budgets related to unallocated funds and trailing costs for the Accenture repatriation have been repurposed.

- A reduction of $7.0 million will be used to help fund labour cost pressures described in Chapter 5, section 5.5.2;
- A transfer of $7.9 million to the Integrated Planning Business Group will be used to fund maintenance cost pressures, as discussed in Chapter 5, section 5.8; and
- A transfer of $2.0 million to the Operations Business Group will be used to provide supplemental funding for the annualized cost of the John Hart operating agreement with InPower, as described in Chapter 5, section 5C.6.3.

5G.7.3 Fiscal 2020 and Fiscal 2021 Plan Operating Costs

Table 5G-12 Corporate Costs Operating Costs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Operating Costs ($ million)	5.7 L4	17.2	13.1	18.4	28.4	19.7	38.9	13.0	13.0

Corporate Costs are decreasing by $25.9 million from the fiscal 2019 forecast to fiscal 2020 and fiscal 2021 plan. As discussed above, the budgets related to unallocated funds and trailing costs for the Accenture repatriation are being repurposed and the compliance filing adjustment is included in the Standard Labour Rate.

The remaining $13.0 million in Corporate Costs is for insurance policies and annual recovery levies, as described above.

5G.8 Capitalized Costs

5G.8.1 Description

In this Application, eligible and a portion of ineligible capitalized overhead costs have been consolidated under Capitalized Costs. In the Previous Application, eligible capital overhead costs were included in the Business Unit Support KBU of the Capital Infrastructure Project Delivery Business Group while IFRS ineligible capital overhead costs were included in Corporate Costs in the former Operations Support Business Group.

Capitalized Costs consists of two components:

- Eligible capital overhead; and
- IFRS ineligible capital overhead.

Eligible capital overhead costs are costs that are eligible for capitalization under IFRS IAS 16, Property, Plant and Equipment. These costs are recorded in operating expenses and then allocated to capital projects using capital overhead loading rates (i.e., capitalized).

These costs are determined by multiplying the forecast eligible operating expenses by resource (e.g., materials, labour and services) by the eligible capital overhead percentages of each organizational group.

The eligible capital overhead percentages for each organizational group are based on the IFRS Capital Cost Allocation study completed in 2012 with subsequent adjustments for changes in resourcing, work responsibilities and the cost distribution approach (e.g., direct charging to capital rather than allocating through capital overhead), that have occurred since the completion of the study. The study was reviewed by KPMG and was undertaken for the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application. The study's purpose was to determine the amount of costs eligible for allocation to capital under IFRS.

The IFRS ineligible capital overhead reflects the amount of operating costs that were previously eligible for capitalization under Canadian Generally Accepted Accounting Principles (**CGAAP**), Section 3061, Property, Plant & Equipment, but are ineligible for capitalization under IFRS IAS 16. IFRS IAS 16 requires that additions to Property, Plant and Equipment must be "directly attributable" to the asset. Unlike previous CGAAP, costs related to administration and general overhead are excluded from Property, Plant and Equipment.

The IFRS ineligible capital overhead amount determined at the time of transition to the Prescribed Standards (which include the principles IFRS), is being phased into operating expenses over a 10-year period, starting in fiscal 2013, rather than immediately being absorbed in rates. This means that IFRS ineligible capital overhead will be fully phased into operating costs by the end of fiscal 2022. This approach avoided an immediate and significant rate impact in fiscal 2013. The IFRS ineligible capital overhead annual credit amounts planned in Capitalized Costs are the annual amounts transferred to the IFRS Property, Plant and Equipment Regulatory Account. The amounts transferred to this regulatory account are reduced by $22.4 million each year, consistent with the 10-year phase-in approach. Further information on the IFRS Property, Plant and Equipment Regulatory Account is provided in Chapter 7, section 7.8.20.

5G.8.2 Fiscal 2020 and Fiscal 2021 Plan Operating Costs

Table 5G-13 Capitalized Costs Operating Costs

		Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Eligible Capital Overhead ($ million)		(68.2)	(67.0)	(69.0)	(69.0)	(69.7)	(70.4)	(71.0)	(71.4)
2	Ineligible Capital Overhead ($ million)		(112.0)	(112.0)	(89.6)	(89.6)	(67.2)	(67.2)	(44.8)	(22.4)
3	Total Overhead	5.7 L18	(180.2)	(179.0)	(158.6)	(158.6)	(136.9)	(137.6)	(115.8)	(93.8)

The decrease in the planned credits in Capitalized Costs for fiscal 2020 and fiscal 2021 compared to fiscal 2019 forecast is primarily due to the annual reduction of $22.4 million per year to phase the IFRS ineligible capital overhead costs into operating costs over a 10-year period, as described above.

5G.9 Post-Employment Benefit Costs

Post-employment benefit costs are comprised of a number of components that are categorized as either current service costs or non-current service costs:

- **Current service costs** are the annual costs of accruing employees' post-employment benefits. These costs recognize the cost of the future benefits earned by the employees in the current year. Current service costs are included in the Standard Labour Rates and charged to current work (capital and operating). Therefore, these costs are reflected in the costs presented throughout this Application; and
- **Non-current service costs** are comprised of plan income on pension plan assets and interest expense on post-employment benefit liabilities. While non-current service costs are included in finance charges, the discussion on non-current service costs is included below so that current and non-current service costs are discussed together in one section within this Application.

This section has been prepared under International Accounting Standard 19, Employee Benefits (**IAS 19**), with the exception of the return (investment income) on pension plan assets which is determined and based on the expected long-term rate of return rather than the liability discount rate as specified by IAS 19. The expected long-term rate of return reflects BC Hydro's expected earnings on pension plan assets. This forecast methodology is consistent with the methodology used in previous revenue requirement applications.

BC Hydro's external actuary performs an actuarial valuation of its post-retirement benefit plans for accounting purposes using the actuarial cost method prescribed by IAS 19. An actuarial valuation estimates the plans' funded status (assets less liabilities) at a specific point in time. In addition, an actuarial valuation also estimates the annual current service costs. At each actuarial valuation, the plan membership is updated, and all economic and demographic assumptions are reviewed and updated as required. An actuarial valuation is required to be performed at least every three years and actuarial projections are performed in between actuarial valuation years. The last actuarial valuation was performed as at December 31, 2015, and an actuarial valuation is currently being performed as at December 31, 2018 which will be completed by September 2019.

In accordance with BCUC Order No. G-47-18 to the Previous Application, the discount rate used to forecast post-employment benefit plan costs is based on the market discount rate in effect at the time the forecast was prepared. The discount rate is calculated in accordance with IAS 19 by BC Hydro's external actuary and is based on a hypothetical basket of high quality corporate debt (AA) that has the same cash flow as the BC Hydro post-employment benefit plans, in terms of both timing and amount. The discount rate in effect at the time the fiscal 2020 and fiscal 2021 forecast was prepared (as at September 30, 2018), was 3.83 per cent for the pension plans and 3.79 per cent for the other post-employment benefit plans.

5G.9.1 Current Service Costs

Current service costs are the annual costs of accruing employees' post-employment benefits. These costs recognize the cost of the future benefits earned by the employees in the current year. Current service costs are included in the Standard Labour Rates and charged to current work (capital and operating). Therefore, these costs are reflected in the costs presented throughout this Application.

Current service costs are sensitive to changes in the discount rate. A decrease in the discount rate will increase current service costs while an increase in the discount rate will decrease current service costs.

Current service costs are shown below in Table 5G-14.

Table 5G-14 Current Service Costs

($ million)	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Current Service Costs	103.8	103.8	105.3	101.2	107.0	107.0	103.5	105.6

The decrease in the planned current service costs for fiscal 2020 and fiscal 2021 compared to fiscal 2019 forecast is primarily due to the elimination of Medical Services Plan premiums. In the Budget 2017 Update, the Government of B.C. announced a 50 per cent reduction to Medical Services Plan premiums, effective January 1, 2018. In February 2018, as part of Budget 2018, the Government of B.C. announced that Medical Services Plan premiums will be eliminated effective January 1, 2020. Current service costs are forecast to increase slightly from fiscal 2020 plan to fiscal 2021 plan due to forecast salary increases.

5G.9.2 Non-Current Service Costs

Non-current service costs are comprised of plan income on pension plan assets and interest expense on post-employment benefit liabilities:

- Plan income (i.e., investment income on pension plan assets) is calculated by multiplying the expected long-term rate of return by the market value of the plan assets at the beginning of the fiscal year, adjusted for expected contributions and benefit payments during the year.

The expected long-term rate of return on the pension plan assets is determined based on the actual asset allocation of the BC Hydro registered pension plan. A decrease in the expected long-term rate of return on pension plan assets will decrease the amount of plan income recognized, while an increase in the expected long-term rate of return on pension plan assets will increase the amount of plan income recognized. The market value of the plan assets is provided by the British Columbia Investment Management Corporation; and

- Interest expense, also known as interest accretion, relates to the expected increase in the discounted pension benefit obligation to recognize the passage of time.

  Interest expense is calculated by multiplying the discount rate by the amount of the pension obligation at the beginning of the fiscal year adjusted for the accrual of current service costs and expected benefit payments during the year. A decrease in the discount rate will result in a decrease in interest expense, while an increase in the discount rate will result in an increase in interest expense.

Non-current service costs are shown below in Table 5G-15.

Table 5G-15 Non-Current Service Costs

	F2019 RRA			F2020 Plan			F2021 Plan		
($ million)	**Pension Benefit**	**OPEB**	**Total**	**Pension Benefit**	**OPEB**	**Total**	**Pension Benefit**	**OPEB**	**Total**
Plan Income	(235.8)	N/A	(235.8)	(256.9)	N/A	(256.9)	(268.2)	N/A	(268.2)
Interest Expense	200.6	24.3	224.9	210.1	13.6	223.7	217.8	13.7	231.5
Total	(35.2)	24.3	(10.9)	(46.8)	13.6	(33.2)	(50.4)	13.7	(36.7)

Plan income and interest expense costs are separated into the portion related to the BC Hydro registered pension plan and the portion related to other post-employment benefit plans which includes post-retirement medical, extended health, dental benefits and the supplemental pension plan. Other post-employment benefit plans do not have plan income as they are unfunded plans and therefore have no assets in which to earn income.

Non-current service costs are included in finance charges, as shown in Appendix A, Schedule 8.0, line 17.

BC Hydro
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Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Chapter 6

Capital Expenditures

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6.1 Introduction

This chapter explains BC Hydro's capital planning and delivery processes as well as our planned capital expenditures and additions in fiscal 2020 and fiscal 2021. Capital "additions" are the capital investments that are affecting rates during the test period, which occur when the capital assets enter service. Capital "expenditures" reported in this chapter represent spending incurred on capital assets that will not affect rates until the capital assets enter service.

The capital forecasts in this chapter are derived from the fiscal 2020 to fiscal 2024 Capital Plan (**Capital Plan**) that BC Hydro finalized in October 2018. The Capital Plan supported the Comprehensive Review and contains investment-level detail for fiscal 2020 to fiscal 2024, and a high-level investment projection for fiscal 2025 to fiscal 2029.

BC Hydro has well-established and well-performing practices for the planning and delivery of capital investments. In December 2018, the Office of the Auditor General of B.C. released an independent audit of Capital Asset Management in BC Hydro. The audit found that BC Hydro has good asset management practices as a result of a decade-long plan and associated efforts and had no recommendations for improvement. This audit is included as Appendix F. In 2016, BC Hydro completed its second Organizational Project Management Maturity Model Assessment and placed in the top-tier of participating organizations from around the world. Also in 2016, BC Hydro received the Project Management Office of the Year Award from the Project Management Institute, recognizing superior organizational project management capabilities.

A key metric to evaluate BC Hydro's performance in the delivery of capital projects is to compare the actual project costs for in-service projects to the original approved expected cost, over an aggregated five-year period. Projects included in this metric for the five-year period of fiscal 2014 to fiscal 2018, had an aggregate original approved expected cost of $6.936 billion. The actual aggregate costs for these projects were $27.9 million (or 0.40 per cent) over the original approved expected cost. Since 2014 when BC Hydro began measuring its capital delivery performance with a five-year aggregate, it has ranged from -4.75 per cent to +0.40 per cent of the original approved expected cost.

Planned capital expenditures and additions in fiscal 2020 and fiscal 2021 are lower than the fiscal 2017 to fiscal 2019 period[285] due to the completion of major projects such as the John Hart Generating Station Replacement project.

This chapter is organized around the following key points:

- Section 6.2 explains how the information provided in this application is aligned with BC Hydro's Revised Proposal filed on June 13, 2018 in the Capital Expenditures and Projects Review proceeding. It also identifies how BC Hydro has responded to the BCUC's Decision on our Previous Application;
- Section 6.3 describes our four-step Enterprise Capital Planning Process which balances affordability and system performance. It explains how this process was applied to create the Capital Plan that forms the basis of the capital investment information in this application;
- Section 6.4 describes how our Power System capital investments, which includes Generation, Transmission and Distribution Assets, are appropriately planned, delivered and forecast for the test period. The section describes the nature of the assets, the bottom-up planning processes, the delivery processes, and provides the forecast capital expenditures and additions; and
- Sections 6.5 through 6.9 describe our Technology, Properties, Fleet and Business Support and other capital investments including the nature of these investments and how they are appropriately planned, delivered and forecast for the test period.

[285] Based on average annual amounts and excluding the Site C Project and BC Hydro's acquisition of Teck Resources Ltd.'s two-thirds interest in the Waneta generation facility.

6.1.1 Capital Appendices in the Application

In this application, BC Hydro has made efforts to provide additional information on planned capital investments, to improve the presentation of that information and to provide the BCUC with additional comfort around our planning and delivery processes. To that end, the information in this chapter is supplemented by the following capital-related information in the appendices of this application:

- Appendix A, Schedule 13 compares planned and actual capital expenditures and additions for fiscal 2017 to fiscal 2018, planned and forecast capital expenditures and additions for fiscal 2019 and planned capital expenditures and additions for fiscal 2020 and fiscal 2021;
- Appendix F provides the Office of the Auditor General of B.C. Report, titled Independent Audit of Capital Asset Management in BC Hydro. This report, which was published in December 2018 found that BC Hydro is managing its assets well, with appropriate information, practices, processes and systems and had no recommendations for improvement;
- Appendix G, section 5 provides explanations of material variances between planned and actual capital expenditures and additions for fiscal 2017 and fiscal 2018. As discussed in the appendix, variances are generally due to the timing of project cash flows or changes in project schedule;
- Appendix H provides BC Hydro's Capital Plan with an outline of major investments, related risks, and opportunities. It provides an overview of the capital investments that BC Hydro expects to undertake in the test period, within the context of BC Hydro's Capital Plan for the next five years (fiscal 2020 to fiscal 2024);[286]

[286] In this application, the Capital Plan provides investment-level details for the fiscal 2020 to fiscal 2024 period, and a high level investment projection for the fiscal 2025 to fiscal 2029 period. Detailed capital investment requirements beyond fiscal 2024 will be informed by future initiatives, including BC Hydro's next Integrated Resource Plan (**IRP**). The first two years of planned capital expenditures and additions contained within the Capital Plan form the basis for the capital-related evidence contained within this application.

- Appendix I provides capital investment information for projects that are greater than $2 million for technology or greater than $5 million for other projects, with planned capital expenditures or additions in the test period. In this application BC Hydro has provided additional project related information, consistent with BC Hydro's Revised Proposal filed on June 13, 2018 in the Capital Expenditures and Projects Review proceeding;
- Appendix J provides capital project descriptions for 75 projects and programs of projects with planned total capital expenditures greater than $20 million, with planned capital expenditures or additions in the test period. This information includes a project description, key drivers, issues addressed by the project, and where relevant, a discussion of project alternatives, implementation risks and risk treatment;
- Appendix K provides summaries of Strategies, Plans, and Studies. These documents are developed to seek solutions to invest effectively in the Power System and related infrastructure. These Strategies, Plans, and Studies investigate and/or recommend broader regional, system, or business unit solutions or policies. The summaries provided in Appendix K provide context for the projects listed in Appendix I;
- Appendix L provides BC Hydro's Technology Strategy and Five-Year Plan. This document provides guidance and direction for BC Hydro's future technology investments to manage compliance and security, manage risk and sustain productivity, and enhance business capability. The Plan is evolving and is updated annually;
- Appendix M provides asset health indices for BC Hydro's generation assets. Compared to the Previous Application, the asset health has improved for Key generation facilities, remained variable for Strategic facilities and reduced for Available Energy facilities; and

- Appendix N provides asset health indices for BC Hydro's transmission and distribution assets. The asset health indices indicate that approximately 55 per cent of transmission and distribution assets are in Good or Very Good condition, 35 per cent are in Satisfactory condition and 10 per cent are in Poor or Very Poor condition. It is expected that a certain portion of assets will be in Poor or Very Poor condition at any point in time.

6.1.2 Summary of BC Hydro's Actual and Planned Capital Expenditures and Additions

BC Hydro's actual and planned capital expenditures and additions for fiscal 2017 to fiscal 2021 are provided in Table 6-1 and Table 6-2 below.[287] As shown in these tables:

- Planned capital expenditures and additions in fiscal 2020 and fiscal 2021 are lower than the fiscal 2017 to fiscal 2019 period; and
- BC Hydro's actual capital expenditures and additions in fiscal 2017 and fiscal 2018, as well as forecast capital expenditures and additions in fiscal 2019, are generally expected to be within 5 per cent of planned amounts.[288]

[287] The forecasts for the capital projects and programs included in the fiscal 2020-fiscal 2021 Capital Plan shown in Table 6-1 and Table 6-2 are based on capital project estimates developed as part of the capital planning process. For capital projects that were in progress as of April 1, 2018, the project forecast information reflected in the Application is current as of that date but information for certain projects in progress has been updated for significant events subsequent to this date. As discussed in section 6.4.7.5 to 6.4.7.8, project cost estimates will have different degrees of accuracy depending on the lifecycle phase of the capital project and the project's stage within each phase.

[288] Based on average annual amounts and excluding the Site C Project and BC Hydro's acquisition of Teck Resources Ltd.'s two-thirds interest in the Waneta generation facility. The Site C Project is excluded from this assessment because it is an exempt project and is planned and managed by a separate Business Group within BC Hydro. The Waneta acquisition is excluded because the acquisition opportunity arose after BC Hydro's fiscal 2019 Revenue Requirements Application plan was prepared. Detailed variance explanations for fiscal 2017 and fiscal 2018 are included in Appendix G, section 5.

Table 6-1 BC Hydro Actual and Planned Growth and Sustaining Capital Expenditures Fiscal 2017 to Fiscal 2021[289]

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Generation								
Growth (Schedule 13, Line 1)	20.0	21.2	2.4	10.2	0.7	4.0	3.2	-
Sustaining (Schedule 13, Line 3)	530.0	563.6	534.1	533.9	424.3	365.9	341.8	435.5
Total Generation	550.0	584.8	536.5	544.1	425.0	369.9	345.1	435.5
Site C Project (Schedule 13, Line 8)	742.5	662.7	716.5	704.8	829.2	1,186.8	1,530.0	1,535.5
Generation - Waneta 2/3 (Schedule 13, Line 2)						1,219.5		
Transmission								
Growth (Schedule 13, Line 4)	262.0	247.3	222.0	280.5	192.7	223.7	185.0	198.9
Sustaining (Schedule 13, Line 5)	255.5	268.1	326.3	218.3	373.9	209.1	222.6	286.5
Total Transmission	517.5	515.4	548.3	498.8	566.6	432.8	407.6	485.4
Distribution								
Growth (Schedule 13, Line 6)	224.7	226.0	233.4	287.6	209.5	305.7	300.0	284.6
Sustaining (Schedule 13, Line 7)	185.0	224.5	160.1	235.2	187.6	190.9	187.5	176.8
Total Distribution	409.8	450.5	393.4	522.8	397.0	496.6	487.5	461.4
Business Support								
Technology (Schedule 13, Line 9)	83.9	76.5	93.4	71.2	78.8	95.6	95.6	56.0
Properties (Schedule 13, Line 10)	95.7	86.6	75.0	63.5	88.3	43.5	58.9	55.3
Fleet / Other (Schedule 13, Line 11)	204.7	58.9	48.6	59.6	39.6	67.4	63.6	75.1
Total	2,604.0	2,435.4	2,411.9	2,464.8	2,424.6	3,912.2	2,988.3	3,104.1
Less: Contribution in Aid	(86.4)	(138.4)	(100.2)	(156.3)	(106.4)	(146.9)	(157.8)	(148.4)
TOTAL	2,517.6	2,297.0	2,311.7	2,308.5	2,318.2	3,765.3	2,830.5	2,955.7

289 Variances between actual and Revenue Requirements Application Plan capital expenditures for fiscal 2017 and fiscal 2018 are discussed in Appendix G, section 5.

Table 6-2 BC Hydro Actual and Planned Growth and Sustaining Capital Additions Fiscal 2017 to Fiscal 2021[290, 291]

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Generation								
Growth	26.6	24.2	0.9	9.6	0.2	(1.3)	2.7	-
Sustaining	486.4	318.5	386.2	397.6	1,332.1	1,304.7	312.0	297.0
Total Generation (Schedule 13, Line 13)	513.0	342.7	387.1	407.2	1,332.3	1,303.3	314.7	297.0
Site C Project (Schedule 13, Line 17)						-	27.9	189.4
Generation - Waneta 2/3 (Schedule 13, Line 14)						1,219.5	-	-
Transmission								
Growth	237.1	255.8	222.8	176.9	213.8	309.9	97.9	83.3
Sustaining	255.2	227.1	216.9	230.8	245.0	223.5	195.9	146.3
Total Transmission (Schedule 13, Line 15)	492.3	482.9	439.7	407.7	458.8	533.4	293.8	229.6
Distribution								
Growth	189.8	232.7	241.6	232.2	229.0	305.2	306.9	344.2
Sustaining	182.3	188.3	157.7	213.3	184.0	222.3	195.3	196.5
Total Distribution (Schedule 13, Line 16)	372.1	421.0	399.3	445.5	413.0	527.5	502.2	540.7
Business Support								
Technology (Schedule 13, Line 18)	81.6	81.6	91.1	97.2	112.6	67.1	147.6	75.5
Properties (Schedule 13, Line 19)	68.3	54.8	118.2	126.9	25.5	28.7	39.9	55.6
Fleet / Other (Schedule 13, Line 20)	210.3	85.6	54.5	59.4	45.7	69.8	64.9	71.3
Total	1,737.6	1,468.5	1,489.8	1,543.8	2,387.8	3,749.4	1,391.0	1,459.1
Less: Contribution in Aid	(90.1)	(103.6)	(88.0)	(129.5)	(84.6)	(148.5)	(146.1)	(165.8)
TOTAL	1,647.5	1,364.9	1,401.8	1,414.3	2,303.2	3,600.8	1,244.9	1,293.2

BC Hydro's capital investments generally fall into two broad categories - sustaining and growth:

- Sustaining investments will address reliability, asset condition, regulatory, safety, security and environmental risks, issues and opportunities associated with existing assets. Sustaining investments also include all business support expenditures such as those related to Property, Technology and Fleet assets; and
- Growth projects will help meet load and system growth through the addition of system capacity and by connecting new electricity supply. Growth expenditures and additions include BC Hydro's acquisition of Teck Resources Ltd.'s

290 Variances between actual and Revenue Requirements Application Plan capital additions for fiscal 2017 and fiscal 2018 are discussed in Appendix G, section 5.

291 The fiscal 2019 forecast amount of $(1.3) million in Generation Growth relates to the return to stock of materials that were not required for a project.

two-thirds interest in the Waneta generation facility and the Site C Project expenditures, which have been individually identified in Table 6-1 and Table 6-2.

Planned capital expenditures and additions in fiscal 2020 and fiscal 2021 are lower than the fiscal 2017 to fiscal 2019 period[292] due to the completion of major projects such as the John Hart Generating Station Replacement project.

As discussed in Chapter 7, section 7.8.2, any differences between the forecast and actual amortization of capital additions are captured in the Amortization of Capital Additions Regulatory Account. This means that the actual amount recovered from ratepayers is ultimately based on the actual capital additions.

BC Hydro's actual capital expenditures and additions in fiscal 2017 and fiscal 2018, as well as forecast capital expenditures and additions in fiscal 2019 are generally expected to be within 5 per cent of planned amounts.[292] Detailed variance explanations for fiscal 2017 and fiscal 2018 are included in Appendix G, section 5.

6.2 The Application Provides Additional Information and Reflects the BCUC's Decision

This section identifies how BC Hydro has responded to the BCUC's recommendations on capital investments in its Decision on our Previous Application. It also explains how the information provided in this application is aligned with BC Hydro's revised proposal to the BCUC's Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding.

[292] Based on average annual amounts and excluding the Site C Project and BC Hydro's acquisition of Teck Resources Ltd.'s two-thirds interest in the Waneta generation facility.

6.2.1 We Have Performed Well in the Planning and Delivery of Large Capital Projects

In the Previous Application, BC Hydro discussed its strong track record in delivering the overall capital portfolio on budget. From fiscal 2012 to fiscal 2016, projects were delivered 0.18 per cent under budget in aggregate.

In its Decision on the Previous Application, the BCUC recommended that the adequacy of BC Hydro's planning and execution related to large capital projects be explored.[293] In the sections below, we describe how BC Hydro's project management processes have been endorsed by independent third-parties and provide statistics that demonstrate that BC Hydro's performance on large projects is similarly strong.

6.2.1.1 Independent Third-Parties Have Endorsed BC Hydro's Project Management Processes

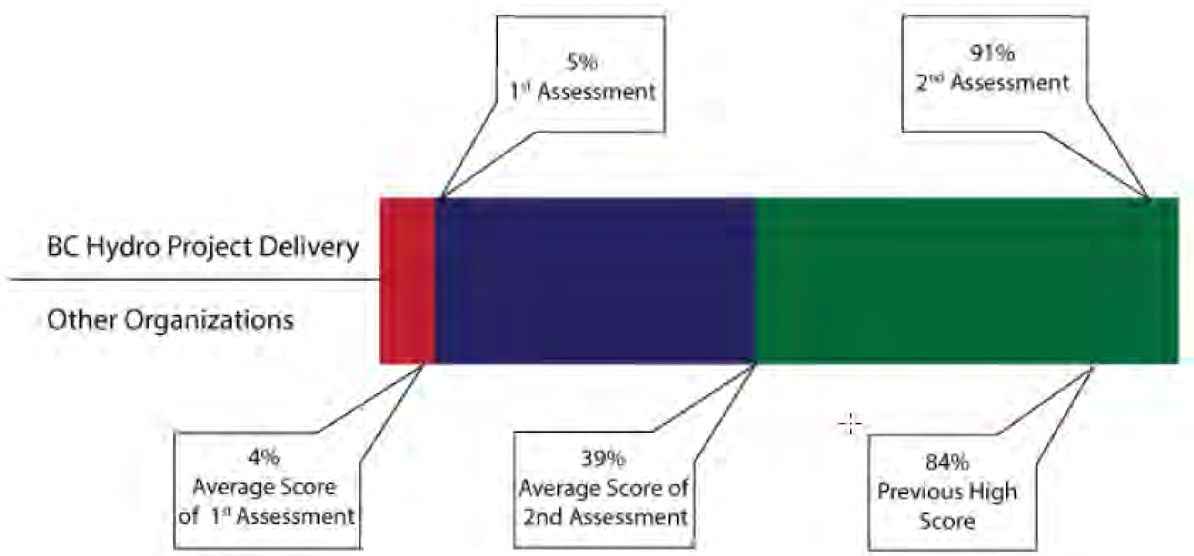
BC Hydro has well-established and well-performing practices for the planning and delivery of capital investments. These practices have recently been recognized and endorsed by the following independent bodies:

- In December 2018, the Office of the Auditor General of B.C. released an independent audit of Capital Asset Management in BC Hydro. The audit found that BC Hydro has good asset management practices as a result of a decade-long plan and associated efforts, with no recommendations for improvement. On page 17 of the report the Auditor General stated: *"BC Hydro has a generally advanced level of maturity in asset management. Its success in this regard is a result of concerted effort over several years by a set of skilled professionals focused on ensuring that a reliable source of electrical power will be supported by a mature asset management practice."* This audit is included as Appendix F.

[293] The BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 45.

- In 2016, BC Hydro completed its second Organizational Project Management Maturity Model Assessment, receiving the highest score among approximately 50 participating organizations from around the world. BC Hydro received a score of 91 per cent, which represents a significant increase in maturity from our first assessment in 2010. This is shown in Figure 6-1 below.

Figure 6-1 Project Delivery Organizational Project Management Maturity Model 2016 Assessment



- Also in 2016, BC Hydro received the Project Management Office of the Year Award from the Project Management Institute, competing against finalists Entel S.A. and Parker Aerospace. The Project Management Institute was founded in 1969 and matures the profession of project management through globally recognized standards, certifications, resources, tools, academic research, publications, professional development courses and networking opportunities.

6.2.1.2 BC Hydro Has Delivered $6.9 Billion of Projects Within 0.4 per cent of Budget

A key metric that we use to evaluate our performance in the delivery of capital projects is to compare the actual project costs for in-service projects to the Original Approved Expected Cost, over an aggregated five-year period. On this metric, we perform very well.

This performance measure is included in BC Hydro's Service Plan, with a target of actual costs falling within +5 per cent to -5 per cent of the original approved expected cost (First Full Funding) in aggregate, excluding project reserve amounts. This metric is calculated using the results of all Generation and Transmission projects as well as major Distribution and Properties projects.

Projects included in this metric for the five-year period of fiscal 2014 to fiscal 2018 had an aggregate original approved expected cost of $6.936 billion. The actual aggregate costs for these projects were $27.9 million (or 0.40 per cent) over the Original Approved Expected Cost. Table 6-3 below summarizes the aggregate results over the past five years.

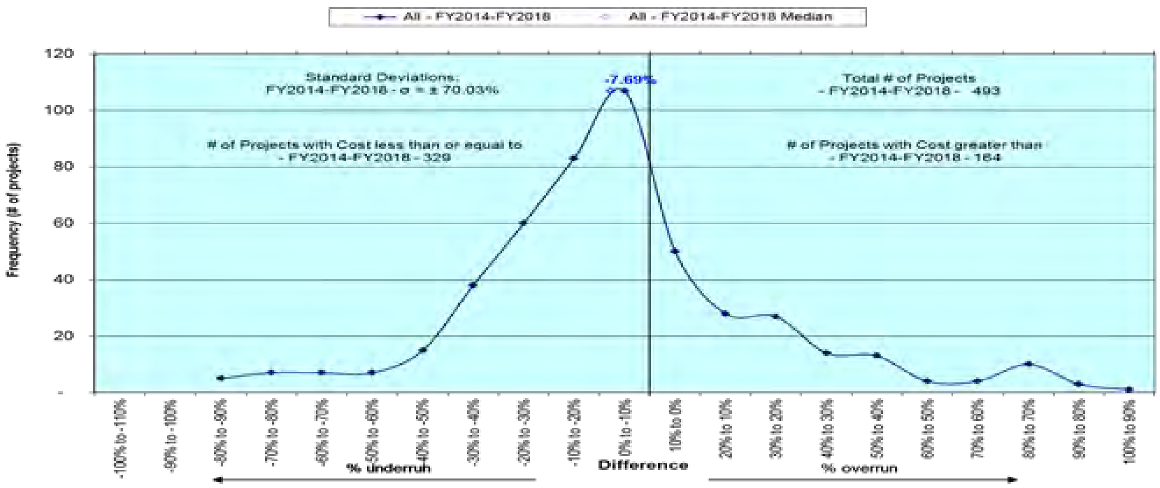
Table 6-3 Five-Year Aggregate Project First Full Funding to Actual Cost (2010 to 2018)

	Capital Infrastructure Project Delivery Project Budget to Actual Cost (2010 - 2018)				
	F2010-F2014	F2011-F2015	F2012-F2016	F2013-F2017	F2014-F2018
# of Projects	661	563	563	540	493
Original Aggregate Budget ($ millions)	3,330	3,924	6,491	6,363	6,936
Actual Aggregate Cost ($ millions)	3,184	3,852	6,479	6,303	6,963
Aggregate Cost Variance ($ millions)	-146.2	-71.8	-12.0	-59.9	27.9
% variance from original budget	-4.39	-1.83	-0.18	-0.94	0.40

Of the 493 projects included in this analysis, 66.5 per cent had an Actual Cost that was less than the original approved expected cost. The median project was 7.7 per cent below the Original Approved Expected Cost.

Figure 6-2 below provides a visual summary of the performance of all 493 projects against the Original Approved Expected Cost.

Figure 6-2 Summary of Actual Cost to Original Approved Expected Cost



6.2.1.3 BC Hydro Performed Well Across Projects of All Sizes, Including Large Projects

The data on completed projects shows that BC Hydro has performed well across projects of all sizes, including large projects. From fiscal 2014 to fiscal 2018, the average variance between the Expected Cost and Actual Cost is:[294]

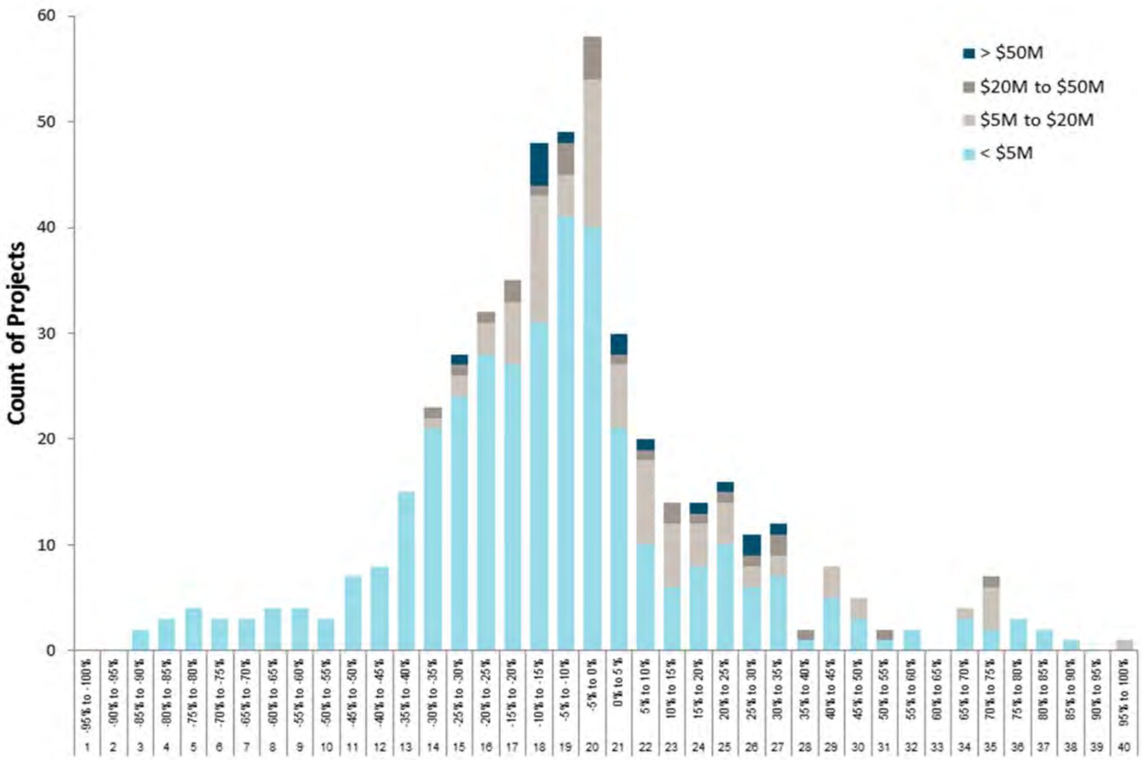
- 1.20 per cent for projects greater than $50 million;
- 0.27 per cent for projects between $20 million and $50 million;
- 2.83 per cent for projects between $5 million and $20 million; and
- -9.82 per cent for projects less than $5 million.

Figure 6-3 below illustrates the distribution of completed projects managed by the Project Delivery KBU within different cost ranges[295] from fiscal 2014 to fiscal 2018.

[294] Based on the most recent Estimate at Completion (**EAC**) amount.

This chart demonstrates that on average, projects fall well within the +15 per cent to -10 per cent preliminary design estimate range, across all four project cost categories, including large projects. Further information on project cost estimate ranges is provided in sections 6.4.7.5 to 6.4.7.8.

Figure 6-3 In-Service Projects (Expected Cost vs Actual Cost) – Fiscal 2014 to Fiscal 2018[296]



The following table provides further information on projects greater than $50 million.

[295] The project categories shown in Figure 6-3 are greater than $50 million EAC (14 projects), between $20 million and $50 million EAC (25 projects), between $5 million and $20 million EAC (87 projects), and less than $5 million EAC (367 projects).

[296] Ten projects had a variance that exceeded 100 per cent and do not appear on the chart. The total EAC for the ten projects is $24.8 million and the total variance was $14.9 million.

Table 6-4 Original Approved Expected Cost vs. Estimate at Completion - Projects Greater Than $50 million (Fiscal 2014 to Fiscal 2018)

Project Title	Original Approved Expected Cost ($000)	Estimate at Completion (EAC) ($000)	Variance ($000)	Variance (%)
GMS G1-5 Turbine Rehabilitation	246,704	183,000	(63,704)	(26)
Mica Unit 5 and Unit 6	700,000	601,385	(98,615)	(14)
Vancouver City Central Transmission	201,000	173,438	(27,562)	(14)
Ruskin Dam and Powerhouse Upgrade[297]	718,036	636,348	(81,688)	(11)
Iskut Extension	126,828	113,300	(13,528)	(11)
Smart Metering Infrastructure	840,000	780,000	(60,000)	(7)
Mica SF6 GIS Replacement	180,625	188,378	7,753	4
Surrey Area Substation	76,405	79,800	3,395	4
Merritt Area Transmission	55,834	58,809	2,975	5
Dawson Creek / Chetwynd Area Transmission	254,100	294,301	40,201	16
Interior to Lower Mainland	657,000	820,100	163,100	25
Northwest Transmission Line	560,998	704,666	143,668	26
Hugh Keenleyside Spillway Gate Upgrade	90,226	114,277	24,051	27
Big Bend Substation	51,299	68,259	16,960	33

In fiscal 2018, BC Hydro completed a total of 58 projects with a total Original Expected Cost of $1.1663 billion and an actual cost of $1.0746 billion, resulting in a favourable variance of $91.6 million (7.8 per cent).

6.2.1.4 A Number of Improvements in Project Delivery Have Been Introduced

Over the past several years, BC Hydro has implemented a number of improvements to the delivery of its capital projects. Further information on these improvements is provided in section 6.4.11.

297 The numbers in this table are different from the numbers in the Ruskin Compliance reports because those reports exclude Implementation Phase capital overhead.

6.2.2 Capital Investment Information In This Application is Aligned with BC Hydro's Capital Expenditures and Projects Review Proposal

On June 13, 2018, BC Hydro filed its Revised Proposal in the Capital Expenditures and Projects Review proceeding. The BCUC established that proceeding to examine how the BCUC reviews BC Hydro's capital expenditures and projects. While that proceeding is ongoing, the information provided in this application reflects BC Hydro's Revised Proposal, which includes additional information to address concerns identified in the scope of that proceeding. Table 6-5 below provides an overview of where this information can be found.

Table 6-5 Capital Related Information Provided in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application

Information Included Consistent with BC Hydro's Proposal	Location
(a) The project's unique planning identification number;	Appendix I Column A
(b) The project's driver;	Appendix J
(c) The project's lifecycle stage or phase;[298]	Appendix I Column D
(d) Key project milestone dates;	Appendix I Columns E, F, G
(e) Project forecast capital additions and expenditures;	Appendix I Columns M, N, O and Q, R, S
(f) An indication of whether a project will be subject to a CPCN or expenditure schedule application;	Appendix I Column U
(g) An indication whether a project is an extension;	Appendix I Column T
(h) If applicable, an indication of which strategies, plans, or studies a project is linked to;	Appendix I Column W
(i) Summaries of the strategies, plans, or studies identified in (h) above;	Appendix K
(j) If applicable, an indication of which projects are part of a Program of Projects;	Appendix I Column X
(k) Description, objectives, scope, schedule, risk and mitigation strategies, and, if available, cost estimates for the programs identified in (j) above.	Appendix J

298 The project's lifecycle stage or phase is referred to as the "Development Stage" in Appendix I.

6.2.3 The Application Provides Additional Information on Technology Investments

This Application also provides additional information on Technology investments in response to the BCUC's comments in its Decision on the Previous Application.

6.2.3.1 Technology Strategy and Five-Year Plan Outline the Supporting Analysis for Technology Investments

In its Decision, the BCUC stated that it was unclear on the types of analysis performed by BC Hydro to support its technology investments. BC Hydro's Technology Strategy and Five-Year Plan (Appendix L) describes the analysis performed to support technology investments, including working with business group leaders and technology teams to move from the current state of technology toward desired business outcomes via an achievable capital portfolio plan. The Technology capital expenditures and additions in the test period have been organized by investment driver categories and are presented in section 6.5.2.

6.2.3.2 BC Hydro Has Implemented a New Benefits Realization Process

The BCUC also stated it was unable to assess how technology investments would result in quantifiable efficiencies and cost savings.[299] BC Hydro has implemented a benefits realization process for technology projects which is described further in section 6.5.5. This process is in place so that:

- Benefits claimed in business cases are realized once projects are in service; and
- Ownership for benefits included in technology project business cases extends beyond project completion.

299 The BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 34.

6.3 BC Hydro's Capital Investment Planning Process

This section describes BC Hydro's enterprise wide capital planning process for capital investments and how this process was applied to create the Capital Plan that forms the basis for the capital-related evidence contained in this application. BC Hydro has planning and governance processes in place across the organization so that the capital investments required to sustain, expand and operate its assets appropriately balance affordability and system performance.

This section is organized around the following points:

- Section 6.3.1: BC Hydro's Enterprise Capital Planning Process facilitates the use of a common approach to planning, prioritizing and governing investments across the company.
- Section 6.3.2: BC Hydro's Executive Team sets the strategic direction and priorities for the annual capital planning process.
- Section 6.3.3: A bottom up planning process is used for each of the asset categories.
- Section 6.3.4: BC Hydro uses a collaborative approach to review the capital portfolios across the enterprise and to develop the Capital Plan.
- Section 6.3.5: BC Hydro has robust processes for the governance, oversight and ongoing management of the Capital Plan.

6.3.1 The Enterprise Capital Planning Process Facilitates a Common Approach Across the Company

In 2017, BC Hydro established an Enterprise Capital Planning Working Group. The purpose of the Enterprise Capital Planning Working Group is to apply a common approach to planning, prioritizing and governing investments across the company.

6.3.1.1 There is Now a Dedicated Working Group With Responsibility for Planning Approach

The Enterprise Capital Planning Working Group includes representatives of all of the KBUs with responsibility for capital investment: Dam Safety, Stations Asset Planning, Lines Asset Planning, Energy Planning and Analytics, Properties, Technology, Finance KBUs, as well as the Fleet department of the Supply Chain KBU.

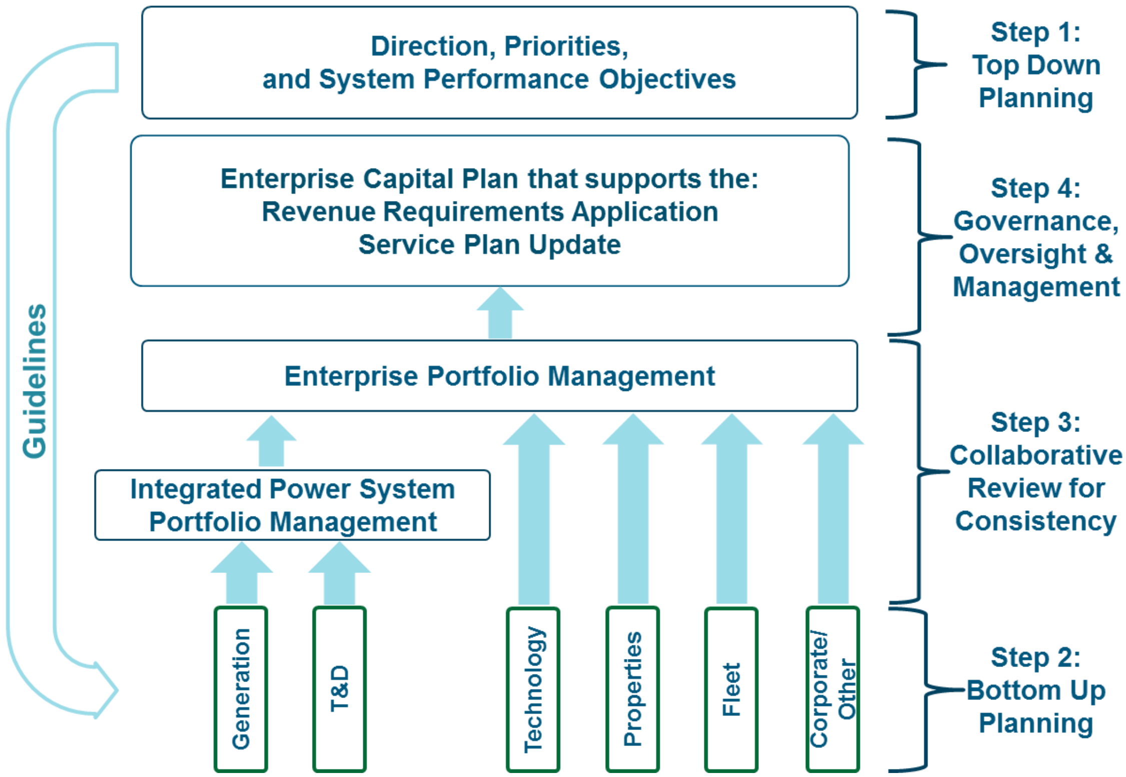
BC Hydro must be flexible and responsive to the investment needs of the system. The Enterprise Capital Planning Working Group manages the annual capital planning process so that the Capital Plan is updated and prioritized to respond to the latest information on the system risks and needs.

6.3.1.2 The Capital Planning Process and Deliverables Are Clearly Articulated

The enterprise wide capital planning process that is overseen by the Enterprise Capital Planning Working Group is clearly defined and the deliverables are well understood by the relevant areas of the business.

Figure 6-4 below provides a simplified depiction of our capital planning process and identifies major outcomes and deliverables of the process. Each step of the process is described in the following sections.

Figure 6-4 Annual Enterprise Capital Planning Process

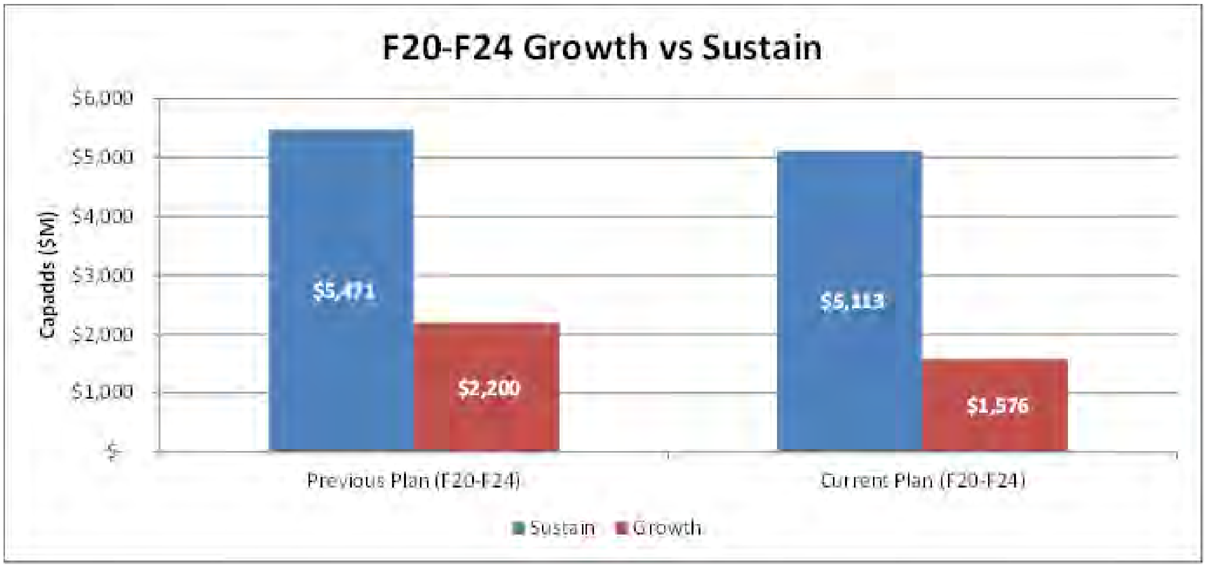


6.3.2 Step 1 - Load Forecast and System Performance Trends Inform Capital Investment Levels

A key element of the annual enterprise capital planning process is the direction provided by the Executive Team on long-term capital investment levels. In providing this direction the Executive Team considers BC Hydro's capital investment needs while balancing affordability, system performance and the need to continue to safely manage our assets. For the planning cycle that informed this application, the Executive Team direction on long-term capital investment levels considered recent trends in forecast load and system performance.

In the following sections, we describe how these trends informed the Capital Plan in this application. Figure 6-5 below illustrates the outcome of this process for the overall level of planned capital additions in the fiscal 2020 to fiscal 2024 period.

Figure 6-5 Comparison of Fiscal 2020 to Fiscal 2024 Planned Capital Additions



6.3.2.1 The Recent Moderation of Forecast Load Growth Allows Moderation of Growth Capital Investment

As discussed in Chapter 3, the demand for electricity is growing at a more moderate rate than previously anticipated. This means that the timing of some planned investments to expand BC Hydro's system has changed and may not be required within the next ten years.

6.3.2.2 Investment in Sustainment Can Be Moderated Due to Strong System Performance

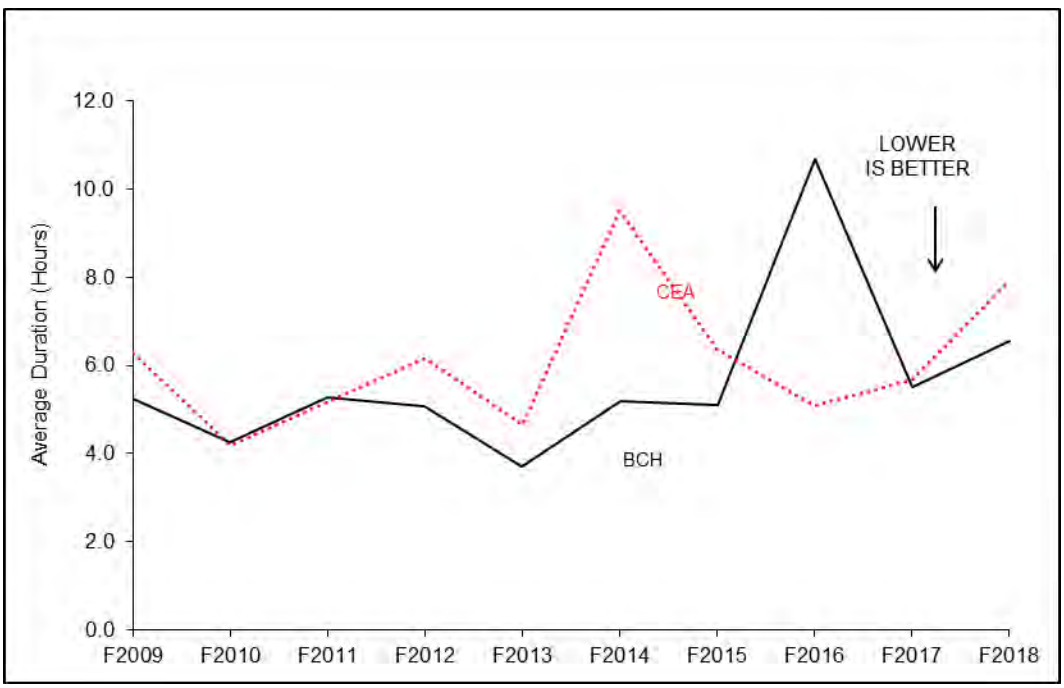
BC Hydro's fiscal 2019 to fiscal 2028 Capital Plan (Previous Capital Plan) had included an increasing level of sustaining expenditures over the ten-year period, primarily driven by the aging system assets and the expected rate of replacement required to maintain system performance.

In recent years, BC Hydro has made significant investments to maintain and, in some areas, improve the Power System. However, over time, the condition of some of the Power System assets has degraded. To this point in time, this degradation has not resulted in a corresponding decline in system performance or customer reliability as measured by two industry-standard metrics. The consistently high level of performance has allowed us to moderate the planned investment in sustainment in the interest of mitigating impacts on customers.

System Average Interruption Duration Index (**SAIDI**) and the System Average Interruption Frequency Index (**SAIFI**) measure the duration and frequency of customer interruptions. BC Hydro tracks these metrics on an ongoing basis. Our performance on SAIDI and SAIFI metrics is also compared regularly with utility industry peers by the Canadian Electricity Association (**CEA**).

Figure 6-6 below shows that in the past decade BC Hydro's unadjusted system average duration ("all-events" SAIDI) trend has performed as good as or better than the CEA composite,[300] with the exception of fiscal 2016 due to the August 2015 summer wind storm.

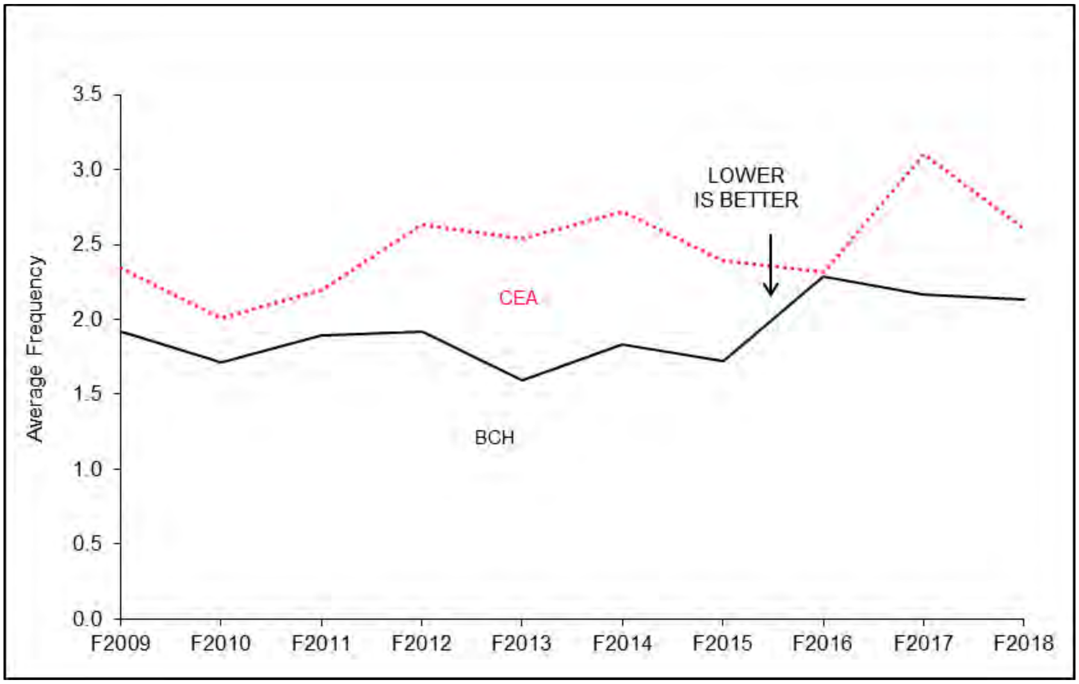
Figure 6-6 SAIDI (All Events, Not Normalized) – Average Interruption Duration per Average Customer



[300] BC Hydro is included in the CEA composite.

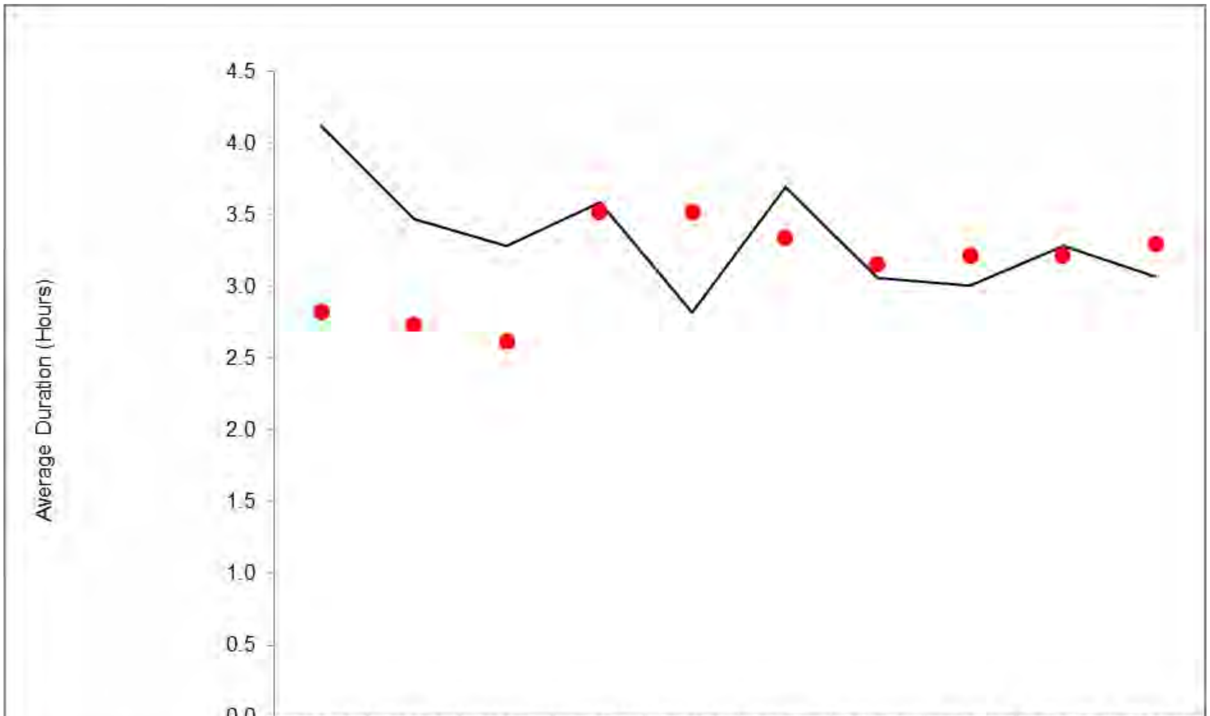
In addition, as shown in Figure 6-7 below, BC Hydro's unadjusted system average frequency ("all-events" SAIFI) trend has consistently out-performed the CEA SAIFI composite.

Figure 6-7 SAIFI (All Events, Not Normalized) – Average Number of Interruptions per Average Customer



As shown in Figure 6-8 below, when outage impact related to uncontrollable major weather events are removed, normalized SAIDI, which measures the total outage duration with storm impact adjustments, experienced by an average customer in a year, was 3.28 hours in fiscal 2017, and further improved to 3.07 hours in fiscal 2018.

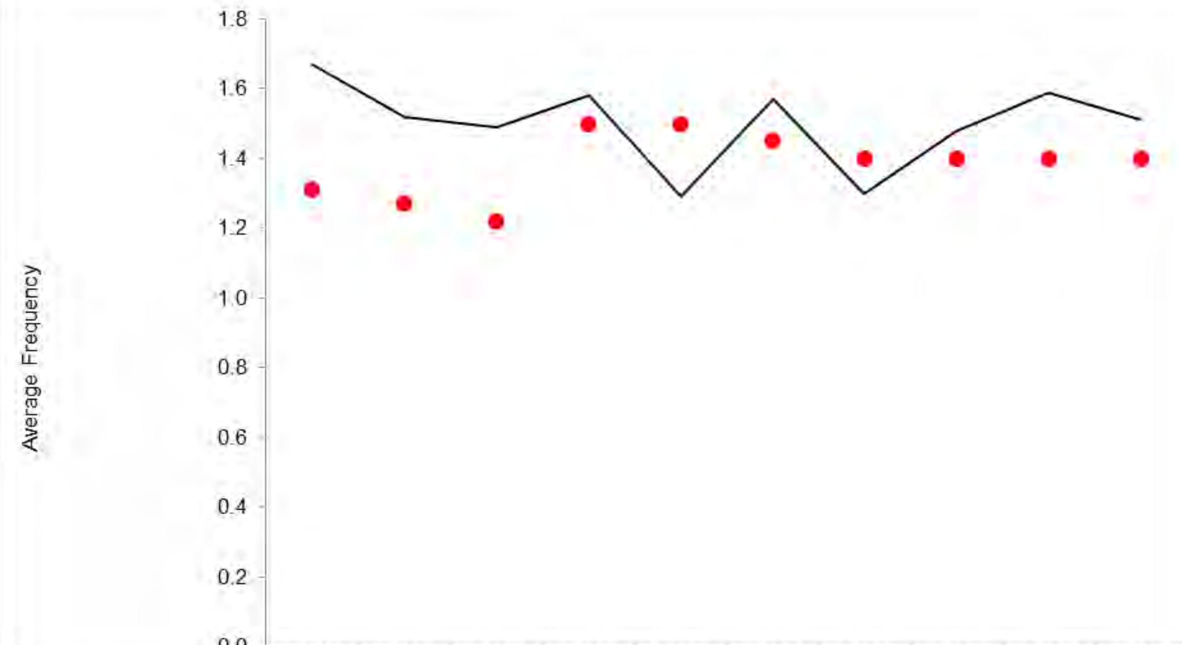
Figure 6-8 SAIDI (Normalized)



	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018
Historical SAIDI	4.12	3.47	3.28	3.59	2.82	3.69	3.06	3.01	3.28	3.07
Historical Targets	2.82	2.73	2.62	3.52	3.52	3.34	3.15	3.22	3.22	3.30

As shown in Figure 6-9 below, normalized SAIFI, which measures the number of sustained disruptions per year excluding major events, was 1.59 disruptions in fiscal 2017, and 1.51 disruptions in fiscal 2018.

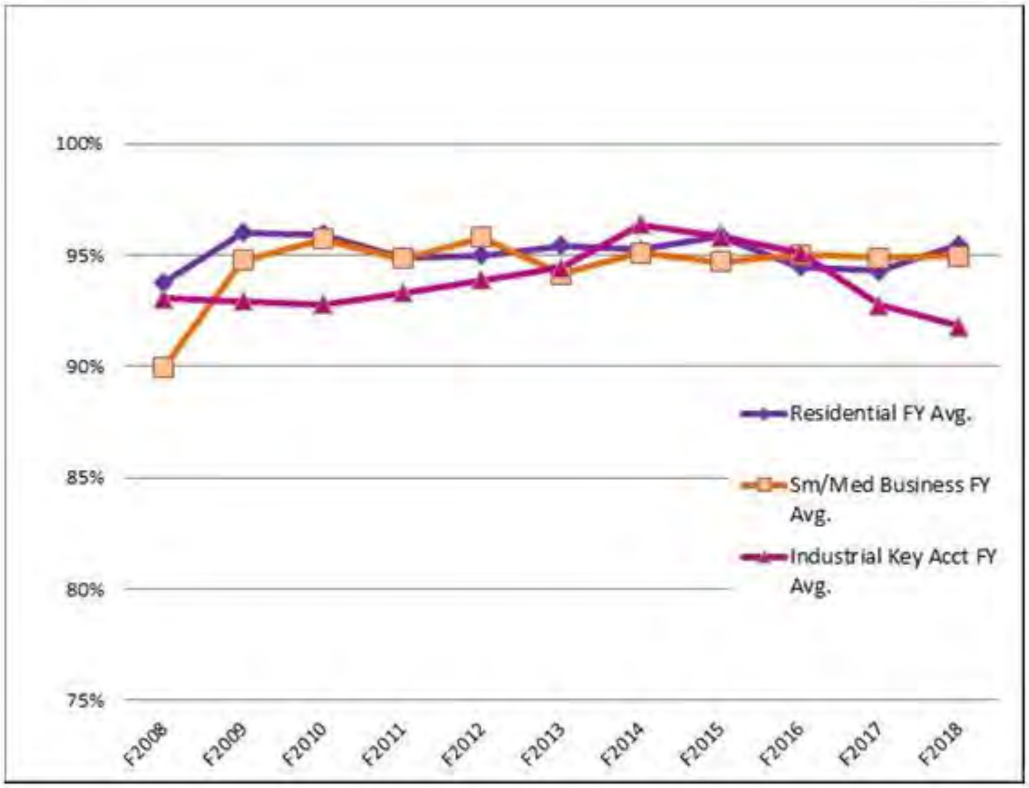
Figure 6-9 SAIFI (Normalized)



	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018
Historical SAIFI	1.67	1.52	1.49	1.58	1.29	1.57	1.30	1.48	1.59	1.51
Historical Targets	1.31	1.27	1.22	1.50	1.50	1.45	1.40	1.40	1.40	1.40

In addition, the reliability scores in BC Hydro's Customer Satisfaction Index indicate that customers continue to be satisfied with the level of reliability they are receiving. This is shown in Figure 6-10 below.

Figure 6-10 Customer Satisfaction Index on Reliability



Lastly, asset-related safety incidents on the transmission and distribution system have declined. This indicates that BC Hydro's investment plans are addressing safety-related risks on the system.

The consistently high level of historic system performance described above presented an opportunity to reconsider the appropriate level of sustaining expenditures. Specifically, for this Capital Plan, BC Hydro considered, at the portfolio level, how to moderate the level of planned sustaining investments, without materially impacting system performance.

As a result of this analysis, the overall portfolio level of sustainment expenditures over the ten-year period was reduced, relative to previously planned amounts. These reductions are targeted as follows:

- **Reductions focused on the last five years**: The majority of the impact was in the last five years of the Capital Plan period (fiscal 2025 to fiscal 2029). Relative to the Previous Capital Plan, expenditures during the first five years of the Capital Plan were relatively unchanged by these planning decisions. Investments in the early years of the Capital Plan were mostly underway and were considered appropriate to continue.
- **Dam safety spending is preserved:** Despite the overall reduction of capital expenditures, Dam Safety investments have not been reduced in response to these planning decisions. Dam Safety risk reduction targets remain consistent with previous capital plans and with the approach approved by the BC Hydro Board of Directors in 2014 to “manage the whole fleet of dams so that there is no significant deterioration in the risk position and that the overall level of risk is kept well within the limits considered to be tolerable.”

6.3.2.3 Reduced Investment Must Be Accompanied by Monitoring of Load Forecasts, Asset Condition and Performance

BC Hydro recognizes that the planned reduction in sustainment expenditures relative to the previous plan must be accompanied by careful monitoring of asset condition and performance. Our objective is to implement the reduction without compromising long-term performance of key assets.

The impact on asset health is expected to vary across the system:

- As explained further in section 6.4.1.2, BC Hydro’s generation facilities are categorized as “Key”, “Strategic” or “Available” according to the significance of the facility to BC Hydro’s system. Under the Capital Plan, the condition of BC Hydro’s “Key” and “Strategic” generation facilities is expected to improve. For example, investments are planned for the G.M. Shrum, Mica, Bridge River and Cheakamus facilities; and
- The recent trend of asset health degradation within some parts of the Power System is expected to continue at this level of capital investment. For example,

over the next five years, the percentage of substation assets in Poor and Very Poor condition is expected to increase from 16 per cent to 19 per cent and the percentage of distribution assets in Poor and Very Poor condition is expected to increase slightly from 13 per cent to 14 per cent. The condition of the assets within BC Hydro's "Available" generation facilities, which provide less than 1 per cent of BC Hydro's annual energy, are expected to continue to deteriorate.

The linkage between asset health and reliability is complex. For example, most of BC Hydro's substations have built in redundancy so that the failure of a single asset will not result in a customer outage. In addition, the installation of automated devices, such as circuit re-closers, on BC Hydro's distribution system, has mitigated the risk of declining reliability from deteriorating asset health. BC Hydro continues to refine the appropriate balance between asset life, system performance and affordability and believes that this reduction in sustainment expenditures will provide more value to both current and future customers.

BC Hydro monitors system performance and forecast demand for electricity at both a system and regional level. Changes in system performance and load forecasts are likely to materialize over time, rather than suddenly. If system performance were to decline or if forecast demand were to change, BC Hydro has options to respond, including:

- Adjusting the level of asset condition driven replacements by redirecting funding from other parts of the BC Hydro capital investment portfolio;
- Updating operational or maintenance practices; and
- Bringing forward investments through our ex-plan governance process, which is described in section 6.3.5.

Overall, based on forecast load growth and system performance, BC Hydro believes that the balance reflected in the planned level of capital investment from fiscal 2020 to fiscal 2024 is appropriate.

6.3.3 Step 2 - Each Asset Category Uses Bottom-Up Planning Processes

Once the long-term capital investment levels have been established, preliminary financial targets are developed for each of the asset categories considering the factors discussed in the previous section as well as the historical composition of the capital plan. These preliminary financial targets are an input into the bottom-up planning process, as shown in Figure 6-4 above.

Within the common Enterprise Capital Planning process, each asset category uses a bottom-up planning process that is tailored to the characteristics of the portfolio, considering:

- The function, criticality, volume and complexity of the different assets;
- The magnitude of the risks, issues and opportunities;
- The size, scope, complexity and costs of the capital investments; and
- The internal stakeholders that should be involved in the process.

The processes used for the asset categories are scaled as required. For example, the largest and most complex portfolios such as Generation or Transmission and Distribution, which collectively comprise the Power System, generally require more complex and detailed planning processes, and involve a broader discussion with internal stakeholders across BC Hydro.

Further information on the specific bottom up planning processes for the Power System, Technology, Properties and Fleet and Business Support/Other can be found in sections 6.5 to 6.8, respectively.

6.3.4 Step 3 - Enterprise Portfolio Management Process Validates and Prioritizes Capital Work Based on Risk and Drivers

Once bottom up planning has concluded, capital planning information is consolidated for:

- Collaborative peer reviews at the enterprise level;
- Validation of alignment with BC Hydro's strategic direction and priorities; and
- Identification of any potential areas for improvement in the process for the next annual capital planning cycle.

Peer reviews are conducted by the Enterprise Capital Planning Working Group, before the enterprise capital plan is submitted to BC Hydro's Executive Team and Board of Directors. The reviews focus on three main areas:

- An overall summary of each asset category portfolio;
- The quality of information used to develop the capital plan; and
- The risk profile of the consolidated capital plan.

The risk profile of the capital plan is based on BC Hydro's enterprise-wide framework for capital prioritization. This framework describes the assessment and prioritization process related to proposed capital investments. Investments are assessed based on the primary driver of the proposed investment, as follows:

- Investments that primarily mitigate risk are scored for prioritization using a methodology that is aligned with the BC Hydro Corporate Risk Matrix; and
- Investments that primarily create value are scored for prioritization using a net value per dollar invested metric. The value prioritization is mainly used for some capital expenditures in the Technology Portfolio.

Through BC Hydro's enterprise-wide framework for capital prioritization, capital investments are classified into one of three categories:

- Mandatory investments driven by legal and regulatory requirements;
- Committed investments not to be postponed. This category includes projects that were prioritized in previous capital plans and are now economically unreasonable to cancel; and
- Investments to be prioritized. This category includes projects that could be re-prioritized without significant costs.

The peer reviews conducted for the Capital Plan in this application resulted in the reallocation of some funding from the Power System portfolio to the Technology and Properties portfolios in the earlier years of the plan. This reallocation was cost neutral and offset by reallocations from Technology and Properties to Power Systems in the later years of the plan. This reallocation increased the amounts allocated to Technology and Properties assets in the earlier years of the plan to smooth the level of investment in these portfolios over the ten-year period and to avoid disrupting BC Hydro's ability to deliver planned investments. As a result, investments in these asset categories are more evenly distributed over the long-term.

6.3.5 Step 4 - Executive Team Reviews and Approves the Capital Plan

The final step in BC Hydro's annual enterprise capital planning process is the review and approval of the capital plan by the Executive Team and Board of Directors, which occurs as part of the annual budget and five-year forecast approval process. This review is conducted to assess whether the plan meets overall business objectives and provides a consistent and appropriate management of risks across all asset categories.

Once the capital plan is approved by the Executive Team, it is monitored, on an ongoing basis, by the Capital Delivery Management Committee. The committee focuses on the early years of the capital plan so that actual and forecast capital expenditures remain aligned with the original capital plan. This management is done at a portfolio level so that, if required, adjustments can be made to re-direct the capital budget, as new information becomes available. To make these decisions, the committee considers financial impacts, the enterprise risk profile, and labour resource availability.

Decisions to reallocate the budget within the capital plan are governed through an ex-plan governance process, which considers the size of the ex-plan request. Requests less than $3 million are reviewed at the Enterprise Capital Planning Working Group level, while requests greater than $3 million are reviewed and approved at the Capital Delivery Management Committee level. Reallocations may result in the approval of new projects to address emerging issues, the advancement of future investments based on new information or the increase of funding to existing programs, in response to identified needs.

6.4 Power System Assets Capital Investments

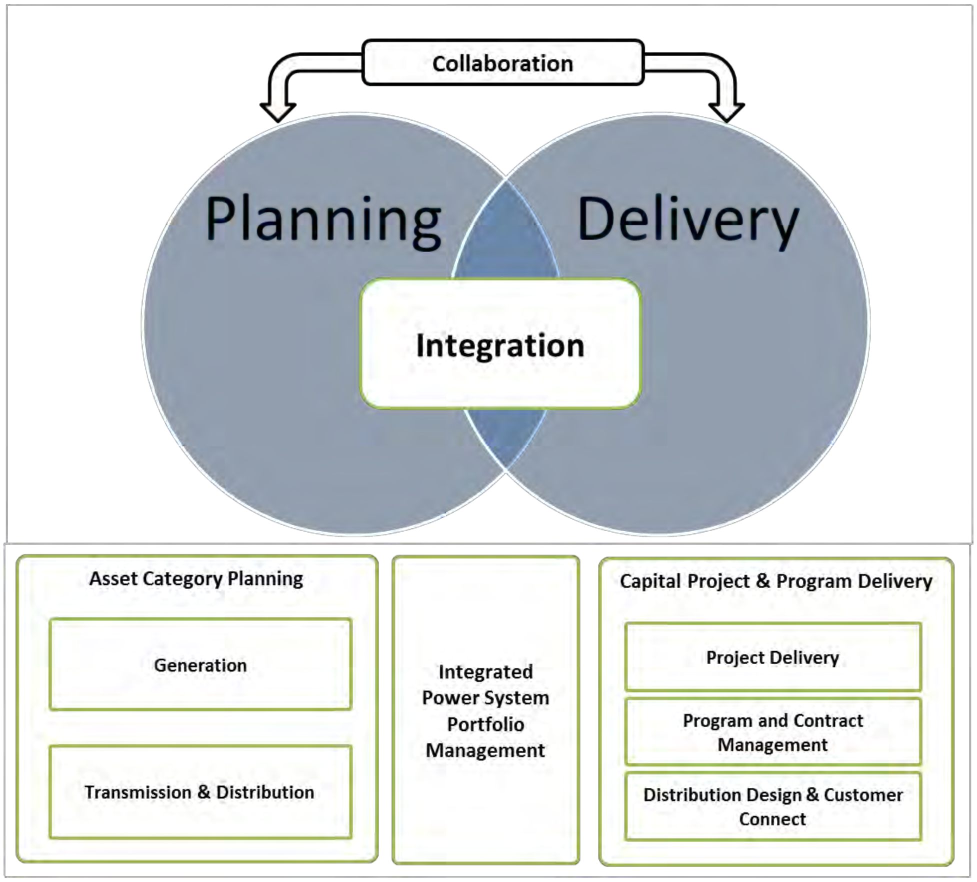
The Power System includes BC Hydro's Generation, Transmission and Distribution assets.

Over time, the condition and performance of existing assets degrade, regulatory and safety requirements change and new assets are required to address load growth and connect new customers. Together, these factors create issues, risks and opportunities to be addressed through capital investment.

The planning and delivery processes for the Power System are integrated, requiring a high degree of collaboration across the organization.

Figure 6-11 below represents a high level depiction of the interaction between functional groups responsible for asset management and planning, and portfolio delivery when planning and delivering capital investments for the Power System.

Figure 6-11 Integrated Power System Planning and Delivery



Planning processes are in place to understand the issues, risks and opportunities associated with the assets and to identify the recommended capital investments.

- Sections 6.4.1 to 6.4.4 provide further information on the Power System assets, the bottom-up planning processes for each asset category and the integrated portfolio planning process for the Power System; and
- Sections 6.4.5 to 6.4.6 provide an overview of the collaboration and integration between planning and delivery through the annual capital planning process, the work planning process and the release of projects and programs to the KBUs responsible for delivery.

Delivery processes are in place to deliver projects and programs on time and on budget, and within scope. Investments associated with the Power System are delivered by three different KBUs: Project Delivery, Program and Contract Management and Distribution Design and Customer Connect.

- Sections 6.4.6 to 6.4.9 explain how investments are assigned to each KBU as well as the project delivery practices used to deliver those investments;
- Section 6.4.10 describes the financial approval policies and procedures applicable to all capital investments; and
- Section 6.4.11 describes recent improvements to our project delivery practices.

Lastly, sections 6.4.12 to 6.4.15 present our forecast capital expenditures and additions for the Power System by asset category.

6.4.1 Generation Assets Capital Investments

During the test period, capital investments in generation assets include asset sustainment, dam safety and growth investments. Generation capital expenditures represent approximately 30 per cent of the BC Hydro Capital Plan during the fiscal 2020 to fiscal 2021 test period. The majority (75 per cent) of capital investments in the Generation portfolio during the test period are driven by the need to address issues and risks associated with existing facilities that are aging.[301]

6.4.1.1 Generation Assets Are Aging and a Number Are at End-of-Life

BC Hydro's generation assets are aging, and a number of generation assets are now at end of life. BC Hydro's generation assets include 83 generating units at 30 hydroelectric generating facilities as well as 81 dams located at generating stations and at additional locations to provide water storage and water diversion functions. Generation assets also include three gas-fired units at BC Hydro's two thermal generating stations and four synchronous condenser units at a dedicated synchronous condenser station. BC Hydro also has 17 diesel generating

[301] Excluding the Site C Project.

stations and one hydroelectric generating station in areas not connected to the integrated electric system.

Construction of most of BC Hydro’s large capacity generating facilities occurred in the 1960s, 1970s and 1980s, while the majority of BC Hydro’s medium capacity facilities were constructed in the 1950s. The age of BC Hydro’s generating facilities ranges from new to 94 years, with an average facility age of 52 years. Asset Health assessments indicate that a number of generation assets are now at end of life. An overview of generation asset health is provided in Appendix M.

BC Hydro manages its generation assets over their lifecycle by:

- Maintaining the assets so that they perform safely and reliably throughout their operating lives;
- Investing in the assets to extend their operating lives, enhance capability, manage risk, and increase efficiency and cost-effectiveness; and
- Managing public and worker safety risks associated with facilities, especially around reservoirs and dams.

Planning processes are in place to support these objectives and to align the portfolio of investments to effectively manage risk and customer needs within financial and labour resource constraints.

With the exception of the Site C Project, which is a growth project, the majority of capital investments in the Generation portfolio during the test period are driven by the need to address issues and risks associated with existing facilities. These investments are categorized as Generation Asset Sustainment and Dam Safety investments. The following sections describe BC Hydro’s Generation Asset Sustainment and Dam Safety portfolios in more detail and then explain BC Hydro’s bottom-up planning process for generation assets.

6.4.1.2 Generation Asset Sustainment Addresses the Highest Risks

The planned generation sustainment capital investments for the fiscal 2020 to fiscal 2021 test period will continue to mitigate or resolve the highest risks identified with BC Hydro's generation assets. Asset Sustainment represents 75 per cent of the Generation expenditures over the fiscal 2020 to fiscal 2021 test period.[302]

The risk assessment considers how important generation facilities are to the overall system, as well as the asset condition.

BC Hydro's generation facilities are categorized as "Key", "Strategic" or "Available", according to the significance of the facility to BC Hydro's system. An investment strategy is in place for each category which reflects the significance of the category of facility to the power system. Table 6-6 below provides a list of BC Hydro's generation facilities by category.

[302] Excluding the Site C Project.

1 Table 6-6 BC Hydro's Generating Facilities by
2 Category

Facility Abb'n	Facilities	Facility Category	Year of Initial Operation	Current Age (Years) 2018	Current Maximum Capacity (MW)	Number of Units
BRR	Bridge River 1 & 2 (Originally developed 1934)	Key (Hydro)	1948	70	417	8
GMS	GM Shrum	Key (Hydro)	1968	50	2916	10
KCL	Kootenay Canal	Key (Hydro)	1975	43	582	4
MCA	Mica	Key (Hydro)	1976	42	2781	6
PCN	Peace Canyon	Key (Hydro)	1980	38	736	4
REV	Revelstoke	Key (Hydro)	1984	34	2368	5
SEV	Seven Mile	Key (Hydro)	1979	39	817	4
WAN	*Waneta (Acquired 2018)*	*Note 1*	*1954*	*64*	*492*	*4*
ALU	Alouette	Strategic (Hydro)	1928	90	9	1
ASH	Ash River	Strategic (Hydro)	1959	59	26	1
BSY	Burrard Synchronous Condenser note 2	Strategic (Synchronous Condenser)	1962	56	N/A	4
CMS	Cheakamus	Strategic (Hydro)	1957	61	160	2
COM	Clowhom	Strategic (Hydro)	1957	61	30	1
FNG	Fort Nelson	Strategic (Thermal)	1999	19	72	2
JHN	John Hart (Originally developed 1947)	Strategic (Hydro)	2018	0	135	3
JOR	Jordan River (Originally developed 1912)	Strategic (Hydro)	1971	47	167	1
LAJ	La Joie	Strategic (Hydro)	1957	61	22	1
LB1	Lake Buntzen (Originally developed 1903)	Strategic (Hydro)	1951	67	60	1
LDR	Ladore	Strategic (Hydro)	1956	62	52	2
PUN	Puntledge (Originally developed 1912)	Strategic (Hydro)	1955	63	26	1
RPG	Prince Rupert Gas	Strategic (Thermal)	1973	45	46	2
RSN	Ruskin (Originally developed 1930)	Strategic (Hydro)	2016	2	106	3
SCA	Strathcona	Strategic (Hydro)	1958	60	63	2
SFN	Stave Falls	Strategic (Hydro)	1999	19	90	2
SON	Seton	Strategic (Hydro)	1956	62	44	1
WAH	Wahleach	Strategic (Hydro)	1952	66	61	1
ABN	Aberfeldie (Originally developed 1922)	Available Energy (Hydro)	2008	10	25	3
ELK	Elko	Available Energy (Hydro)	1924	94	11	2
FLS	Falls River	Available Energy (Hydro)	1930	88	7	2
SHU	Shuswap	Available Energy (Hydro)	1929	89	6	2
SPN	Spillimacheen	Available Energy (Hydro)	1955	63	5	3
WGS	Whatshan (Originally developed 1951)	Available Energy (Hydro)	1972	46	60	1
WHN	Walter Hardman	Available Energy (Hydro)	1960	58	10	2

Note 1	On July 26, 2018, BC Hydro became the sole owner of Waneta. Teck Metals Ltd ("TML") continues to act as the Operator of the facility during the 20 year lease term, and is required to operate, manage, and maintain Waneta in accordance with the terms of the Co-Possessors and Operating Agreement ("COPOA").
Note 2	Burrard Synchronous Condenser facility was previously the Burrard Thermal generating facility.

- **"Key" generating facilities:** Seven "Key" generating facilities represent the largest hydro-electric facilities on the BC Hydro system and produce approximately 90 per cent of BC Hydro's average annual energy;
- **"Strategic" facilities**: Eighteen "Strategic" facilities represent all generating stations on Vancouver Island, all stations located on cascading systems, all thermal generation stations and generating stations required to provide voltage support to the transmission network. These facilities produce approximately 9 per cent of BC Hydro's average annual energy and provide significant additional value to BC Hydro due to their geographic location and system support services;
- **"Available" facilities:** Seven "Available" facilities represent those facilities that are of lower strategic importance and produce less than 1 per cent of BC Hydro's average annual energy; and
- **Waneta two-thirds:** On July 26, 2018, BC Hydro became the sole owner of Waneta. Teck Metals Ltd. continues to act as the Operator of the facility during the 20-year lease term. In that role, Teck is required to operate, manage, and maintain Waneta in accordance with the terms of the Co-Possessors and Operating Agreement ("COPOA"), which includes capital planning and operating to a prudent owner standard, exercising the degree of care and skill of an experienced dam operator and acting in accordance with Good Utility Practice.

  As Teck is the Operator of Waneta, processes that BC Hydro generally uses for internal asset management and planning purposes will not be applied. BC Hydro will retain an oversight role as part of the Waneta Operating Committee, including reviewing the annual operating plans for Waneta.

The condition of assets across BC Hydro's generation fleet is a foundational input to the planning process. BC Hydro evaluates the condition of its major equipment (turbines, generators, governors, exciters, transformers, and circuit breakers) based on the latest available maintenance test and inspection data, following BC Hydro's Equipment Health Rating methodology. This provides a systematic, objective, repeatable, and transparent assessment of equipment health. Factors influencing the Equipment Health Rating include:

- Equipment health;
- Maintenance history;
- Equipment reliability;
- Availability of spare parts;
- Availability of technical support; and
- Known equipment type design problems.

Asset health or condition information is used to assess and manage risk and to prioritize the need to make investments to preserve and sustain the generating units. Each health assessment results in a rating of Good, Fair, Poor, or Unsatisfactory.

Over the test period, sustaining capital expenditures will be focused at the G.M Shrum, Bridge River 1 and 2, Mica, and Cheakamus generating stations.

6.4.1.3 Dam Safety Is Another Focus of Generation Expenditures

Dam Safety represents 25 per cent of the Generation expenditures over the test period,[303] recognizing the potential for catastrophic consequences in the unlikely event of a failure.

BC Hydro's dams are subject to the British Columbia Dam Safety Regulation, which defines a "Dam" as:

(a) A barrier constructed for the purpose of enabling the storage or diversion of water diverted from a stream or an aquifer, or both; and

[303] Excluding the Site C Project.

(b) Other works that are incidental to or necessary for the barrier described in paragraph (a).

Consistent with the Dam Safety Regulation, BC Hydro's Dam Safety portfolio comprises all physical features, structures and mechanisms - both constructed and natural - that retain the reservoirs and control the passage of flows past the dam.

The Dam Safety Regulation classifies dams according to the consequences of their failure, such as the potential for loss of life, environmental damage and economic impacts. Classifications range from "Low Consequence" to "Extreme Consequence". These classifications dictate the required frequency of safety activities performed on the dam and are further used to guide the selection of the dam's design and performance criteria.

Dam Safety issues and risks involve:

- The safe storage and controlled passage of water under normal conditions;
- The ability to pass floods (from the annual freshet to extreme events); and
- The ability to withstand a major earthquake without any harmful release of water.

Dam Safety risks generally have a relatively low probability of occurrence but, if realized, a very high consequence. Key drivers of Dam Safety capital investments in the test period include:

- ***Seismic Risk:*** The seismic performance at a number of BC Hydro's major dams is below current Canadian guidelines. For example, the John Hart Dam is classified as an "Extreme Consequence" dam under the British Columbia Dam Safety Regulation. This means that, under the 2007 Canadian Dam Association Guidelines, the expected seismic performance of this dam is to have no uncontrolled release of the reservoir during and following earthquake ground motions that would be expected to occur on that site no more than once every

10,000 years. Seismic upgrades to the John Hart Dam and spillway are required and planned to achieve this level of seismic performance.

- ***Reliability of Spillway Gates:*** A spillway is an essential component of any dam facility. It provides a means for passing sufficient quantities of water from the reservoir to the downstream water course when power generation is unavailable or insufficient to maintain required downstream flows or prevent the reservoir from rising above its maximum safe elevation. Discharge through a spillway may also be required for emergency reservoir drawdown, such as in the event that a defect develops and/or is identified within the dam and there is a need to reduce the load on the dam. Discharge through a spillway is regulated by gates located at its upstream end. Some of BC Hydro’s spillway gates have design or condition-based deficiencies that impinge upon their operational reliability and which, due to their critical safety function, pose a risk. To address this risk, the Capital Plan includes investments to improve the reliability of spillway gates at the W.A.C. Bennett Dam, Ladore Dam, Strathcona Dam, John Hart Dam and Mica Dam.
- ***Condition of Civil Structures:*** BC Hydro has a number of facilities where the integrity or degradation of the existing civil structures poses a risk to the ability to store or pass water safely. For example, reservoir booms throughout BC Hydro’s system are aging and deteriorating. Poorly functioning booms can allow large debris in the reservoir to reach the dam, blocking spillways and other water passages and interfering with or preventing the proper function of these critical features of a dam. Projects to replace a number of reservoir booms will proceed within and beyond the test period.

6.4.2 Generation Bottom-Up Capital Planning Process

The following sections describe the steps of BC Hydro's bottom-up capital planning process for generation assets.

6.4.2.1 Step 1 - Generation Strategic Asset Management Plan

First, BC Hydro considers its Generation Strategic Asset Management Plan. This plan sets out ten year strategies for each facility category – Key, Strategic and Available - to support appropriate resource allocations and performance targets for the facilities.

- **Key facilities:** BC Hydro has implemented a component replacement strategy for its Key facilities. Under this strategy, all major equipment at Key facilities will be restored to Good or Fair condition or will have work underway to restore them to Good or Fair condition, within ten years. This strategy means that, in aggregate, the reliability of Key facilities will be maintained at or slightly above the average of similar facilities, as reported by the Canadian Electricity Association;
- **Strategic facilities:** Equipment in "Poor" or "Unsatisfactory" condition at Strategic facilities will either be refurbished or replaced within ten years, will have work underway to be refurbished or replaced within ten years or will have a long-term plan developed to mitigate the risk of equipment failure. This strategy means that, in aggregate, the reliability of Strategic facilities will be maintained at or restored to the average of similar facilities, as reported by the Canadian Electricity Association; and
- **Available facilities**: With the exception of Whatshan and Aberfeldie (the largest and newest Available facilities) all other Available facilities will receive minimal capital investment and will be taken out of service when they are no longer able to safely generate electricity. BC Hydro will perform regular maintenance and inspection on these assets to keep them safe and inform investment and operating decisions. Options to re-furbish, re-develop or

decommission Available energy facilities that have been taken out of service will be developed as required. Decisions on these options will be informed by BC Hydro’s long-term load resource balance. Over time, this strategy may result in a gradual reduction of the energy produced by Available facilities.

6.4.2.2 Step 2 - Dam Safety Investment Strategy

Second, BC Hydro’s level of investment in Dam Safety is targeted to address identified deficiencies in the dams and their appurtenant structures so that:

- There is no significant deterioration of BC Hydro’s overall risk position with respect to these assets; and
- The overall level of risk is kept well within tolerable limits as guided by the Canadian Dam Association’s Dam Safety Guidelines and the International Commisison on Large Dams’ Bulletin on Dam Safety Management.

In addition, BC Hydro’s dam safety investments also consider qualitative judgements made, on a case by case basis, with regulators and government representatives, First Nations and stakeholders.

This targeted level of investment accounts for the both the experienced and expected future wear and tear of the dams, identification of new issues, and improved understanding of previously identified issues through engineering investigations.

Identified deficiencies are rated by a “Vulnerability Index” that considers:

- The extent to which the design or performance of a particular dam feature (deficiency) differs from accepted good practice;
- The extent to which that feature contributes to the safe performance of the dam;
- The frequency at which the feature is potentially stressed to the limits of its performance; and

- The effectiveness of any interim risk controls that might be in place.

At each dam, issues and risks are grouped to form a project or set of projects based on asset type, similarity of issues or solutions, and location within the facility or system. These projects are then prioritized across the system by considering:

- The potential reduction of the Vulnerability Index;
- The consequence classification of the dam;
- The cost and time to effect remediation compared to the benefits from risk reduction;
- The sequencing of required enabling projects; and
- The completeness of BC Hydro’s understanding of the issue and potential remediation.

BC Hydro’s most recent internal audit of the Dam Safety Program, conducted by a team that included international subject matter experts in Dam Safety management and hazardous process industries, found that

> “BC Hydro continues to be a leader in risk assessment in the international dam safety community with a transparent, systematic and robust risk assessment process.”

6.4.2.3 Step 3 - Growth Driven Generation Investments

Third, BC Hydro identifies opportunities to enhance the capability or increase the efficiency of existing facilities. Generation growth investments are integrated into the capital plan when there is an identified need for increased energy or capacity resources.

6.4.2.4 Step 4 - Facility Asset Plans

Fourth, BC Hydro considers the Facility Asset Plans for its hydroelectric generating facilities, thermal generating and synchronous condenser stations. Facility Asset Plans formulate, document and recommend a ten year investment strategy for each facility, with a focus on the near years of the plan. These strategies account for the facility's role in BC Hydro's system, its Equipment Health Ratings, dam safety issues and deficiencies, performance levels and targets, risks, and growth opportunities. Capital upgrade projects to implement these strategies are carefully planned so that unit outages and maintenance work are coordinated with power system requirements.

As they are developed, each Facility Asset Plan is presented to the Asset and Risk Planning Committee for agreement in principle and endorsement. This committee provides input to the Facility Asset Plan on all issues, risks and planned investments.

Facility Asset Plans are updated periodically to reflect the latest information, including changes in priorities and strategies which influence the scope and timing of facility plans and investments. A Facility Asset Plan may also be updated if new information emerges that affects the investment strategy for the facility. Between updates, BC Hydro continues to monitor the risks and issues associated with the facilities and makes adjustments, if needed.

Summaries of Facility Asset Plans are provided in Appendix K.

6.4.2.5 Step 5 – Annual Capital Planning Review

Fifth, as part of the annual capital planning process, BC Hydro undertakes a review of the planned investments for each facility. Investments are reviewed to check that the facility asset planning process has been applied consistently, the data quality is sufficient and the investments are appropriately prioritized and timed. These investments are then submitted into the Integrated Power System Portfolio Management process, as described in section 6.4.5 below.

6.4.3 Transmission and Distribution Assets Capital Investments

Transmission and Distribution capital expenditures represent approximately 60 per cent of BC Hydro's planned capital expenditures over fiscal 2020 to fiscal 2021.

Over the test period, approximately half of the forecast capital investment in the transmission and distribution systems are investments in sustainment to address issues and risks associated with the asset condition of existing facilities. The other half is related to growth.

6.4.3.1 Transmission and Distribution Assets Are Aging and Many Require Investment in the Near Term

BC Hydro's transmission and distribution assets are aging, and the asset health assessment of these assets indicate that a number of them are now at end of life.

BC Hydro's transmission and distribution assets include over 18,000 circuit km of transmission overhead lines, approximately 350 km of transmission subterranean and submarine cables, 323 substations, an integrated telecommunication system, approximately 58,000 circuit km of distribution overhead lines and 10,000 circuit km of distribution underground lines.

A large portion of the transmission system was built in the 1960s and 1970s and these assets are, or soon will be, reaching or exceeding end-of-life condition. Similarly, a large portion of the distribution system has, or soon will be, exceeding its design life. Asset Health assessments indicate that approximately 10 per cent of the transmission and distribution assets are in poor to very poor condition, which requires either remediation work or replacement within the next ten years. It is expected that a certain portion of assets will be in Poor or Very Poor condition at any point in time. An overview of transmission, distribution and substation asset health is provided in Appendix N.

1 Overall, BC Hydro has approximately four million individual transmission and
2 distribution assets. Table 6-7 below provides the average asset age, by asset class.

3 **Table 6-7 Average Asset Age by Asset Class**

	Asset Class	Number of Assets	Average Age
Distribution	Capacitors	405	22
	Cutouts	408,647	17
	O/H Conductors Primary (circuit km)	48,294	30
	O/H Switches	12,343	18
	O/H Transformers	283,161	25
	Others	39,268	
	Recloser	1,400	5
	Revenue Meter	2,035,097	5
	Street Light	91,977	23
	U/G Cables Primary (circuit km)	10,874	20
	U/G Transformers	67,364	22
	Voltage Regulators (Distribution)	575	7
	Wood Poles	891,328	27
	Total:	**3,890,733**	
Substation	Batteries	338	11
	Circuit Breakers	3,994	19
	Disconnect Switches	14,130	30
	Fire Protection Systems	156	28
	Gas Insulated Switchgear	508	16
	Instrument Transformers	8,455	21
	Mobile Transformers and Substations	9	31
	Others	3,225	
	Protection and Control Systems	12,496	24
	Reactors	1,949	28
	Series Capacitors	14	27
	Shunt Capacitors	434	18
	Standby Generators and Fuel Systems	75	23
	Static Var Compensators	5	18
	Station Insulators	435	42
	Surge Arrestors	6,277	14
	Synchronous Condensers	4	47
	Transformers/Tap Changers	1,437	35

	Asset Class	Number of Assets	Average Age
	Voltage Regulators (Substation)	362	38
	Total:	**54,303**	
Transmission	Conductor Systems (circuit km)	19,349	44
	Line Disconnect Switches	286	26
	Metal Support Structures	24,366	44
	Others	319	
	Underground Cables (circuit km)	346	38
	Wood Pole Structures	82,142	44
	Total:	**126,808**	

BC Hydro has established planning processes in place to:

- Develop transmission and distribution system plans for the safe and reliable delivery of electricity to customers;
- Connect new customers and generators;
- Expand networks with existing capacity constraints to meet anticipated load growth;
- Manage asset performance; and
- Meet regulatory requirements.

Over the test period, the transmission and distribution capital forecast includes investments in both sustainment and growth expenditures. As indicated above, approximately 50 per cent are sustainment expenditures, driven by the need to address the issues and risks associated with existing assets. Sustainment expenditures are made so that the assets perform as required throughout their lifecycle. Investments in existing assets include activities such as:

- Replacement of assets based on condition;
- Enhancements to maintain or improve customer reliability and extend asset life;
- Upgrades to mitigate risks including safety, environment, security and seismic;

- Improvements to meet evolving regulatory standards; and
- Relocations to address third-party requests.

6.4.3.2 BC Hydro Is Investing a Similar Amount as in Past Years to Replace Existing Assets

The replacement of assets represents 75 per cent of transmission and distribution sustainment expenditures, or approximately $640 million over the test period. This level of expenditures is similar to the expenditures in the previous three years. While this level of investment will result in a gradual deterioration in overall asset condition of the transmission and distribution assets, the associated risk is mitigated.

Assets are replaced when the equipment performance can no longer be managed due to comparatively high cost or due to lack of parts and inadequate manufacturer support. Asset replacements are also required to mitigate increasing public and worker safety risks as well as environmental risks, which could result from asset failures.

The Asset Health Index is used to assess the condition of the transmission and distribution assets. This approach considers factors such as asset age and available test and inspection data and then assigns ratings of Very Good, Good, Fair, Poor, or Very Poor to each asset. These ratings can be grouped and analyzed to assist with investment decisions.

Most replacements are the result of proactive inspections and maintenance. For example, cedar wood poles are tested and treated 20 to 29 years after initial installation and then every ten years thereafter. Units that fail the test criteria are then scheduled for replacement.

In cases where the impacts of asset failure on customer reliability are low and proactive maintenance is ineffective in extending asset life, a ‘run to failure’ strategy is used to minimize the life cycle costs of managing the assets. Examples of asset classes that are ‘run to failure’ include overhead distribution transformers.

At the level of capital investment in this Capital Plan, the number of assets in Poor or Very Poor condition is expected to gradually increase, which will increase the probability of failure associated with some components of the transmission and distribution system. The potential impact of asset failures on system performance is mitigated by the redundancy on the system as well as the installation of automated devices.

6.4.3.3 Customer Reliability Investments Are Aimed at Managing Current Reliability Levels

Customer reliability investments include upgrades to existing assets as well as adding new assets to manage reliability. Customer reliability capital expenditures are required during the test period to manage current levels of system performance and total approximately $100 million. Examples of customer reliability projects include backup circuit ties to enable faster restoration in the event of customer outages as well as circuit re-locations and re-configurations to avoid potential outage causes, such as tree and vegetation contacts.

6.4.3.4 A Portion of the Sustainment Budget is Directed at Mitigating Other Risks

A portion of the transmission and distribution capital investment portfolio is to address a variety of other risks including public and worker safety, environment, fire, security, seismic and extreme weather.

Capital expenditures to address other risks associated with transmission and distribution are expected to total approximately $45 million in the test period. This includes:

- **Safety risk mitigation**: Examples of safety projects include the replacement of H-Frame structures in the alleys of downtown Vancouver, which pose a public safety risk due to reduced clearances to buildings as well as a project to replace concrete poles, which pose an employee safety risk due to a lack of adequate integral bonding.

- **Environmental risk mitigation**: Examples of environmental projects include those to manage oil-filled equipment to avoid the risk of spills as well as projects to modify structures in areas where protected bird species congregate in order to avoid electrical contract incidents.
- **Fire and security risk mitigation**: Examples of projects to address fire and security risk at substations include the installation or upgrading of fire protection systems or the installation of access detection and control, video monitoring, perimeter fencing and gate upgrades.
- **Extreme weather risk mitigation**: Examples of projects to address risks related to extreme weather include installing piles, reinforcing foundations and constructing protective structures such as retaining walls, riprap berms and debris deflectors around transmission structures and their foundations, to withstand storms, floods, landslides, and avalanches.

6.4.3.5 Localized Growth Investments Are Driven by Emerging Demand

Growth expenditures are required to expand the transmission and distribution system to accommodate load growth and to connect new customers. This includes:

- Upgrades and additions of station equipment;
- Upgrades and additions of transmission lines and distribution feeders; and
- New service connections and upgrades.

Growth expenditures represent approximately 50 per cent of all transmission and distribution expenditures during the test period.

Demand for electricity continues to increase in some areas of the province and certain parts of the BC Hydro system are reaching capacity. In certain sectors of the economy, such as the oil and gas sector in the Peace and North Coast regions, economic growth is driving the need to reinforce the system in areas that do not have the infrastructure to meet the emerging demand. In addition, new investments continue to be required to connect new customers to the BC Hydro system.

Growth investments and their timing are informed by forecast load growth, resource supply additions and existing system capacity.

Capital investments to interconnect transmission customers are also difficult to forecast. Due to uncertain timing, location and scope, only known transmission interconnection projects are included as specifically identified projects in the forecast capital expenditures for the test period.

BC Hydro also includes provisions for emerging transmission interconnection projects. These amounts are aligned with the historical levels of spend and anticipated future activity. Deviations from these provisions, to respond to emerging interconnection needs, require an adjustment of the timing or scope of other projects and programs within the capital plan.

Due to the continued economic activity expected in the Liquefied Natural Gas and Oil and Gas sectors, there are potentially significant upgrades to the transmission system in the North Coast and Peace region that may be required in the near future. These potential upgrades, including a project to convert the voltage of the electric supply in the Dawson Creek area from 138 kV to 230 kV, are not currently included in BC Hydro's Capital Plan. These projects would allow BC Hydro to serve potential new LNG and oil and gas customers with clean renewable energy from the power grid. BC Hydro will work with the load customers to define the need and scope of these future projects. These projects will proceed once there is a formal commitment from the potential customers. Depending on the timing, these projects will be either incorporated in future annual capital plan updates or initiated under BC Hydro's ex-plan governance process, described in section 6.3.5.

Distribution interconnection expenditures are more stable and are forecast based on historical levels.

6.4.4 Transmission and Distribution Bottom-Up Capital Planning Process

The following sections describe the steps of BC Hydro's bottom-up capital planning process for transmission and distribution assets.

6.4.4.1 Step 1 – Identify the System and Asset Needs

First, BC Hydro identifies system and asset needs to be considered for remediation. This assessment includes reviews of system performance data to identify assets with degrading conditions, representing safety or environmental risks, not performing adequately or not meeting regulatory requirements. System and substation load forecasts are also developed to identify areas in the system that may require reinforcement. Based on these reviews, BC Hydro develops a preliminary approach and timeline for remediation.

The following information and data is used to assess system and asset needs:

- ***Asset Health and Performance:*** BC Hydro evaluates the condition of the Transmission and Distribution assets, based on the latest available maintenance test and inspection data, as well as engineering assessments and assigns an Asset Health Index to each asset. The methodology provides assessments that are objective, repeatable, and consistent across asset classes. Assets with an index of Very Poor are generally considered for reinvestment within three years and assets with an index of Poor are generally considered for reinvestment within ten years. The Asset Health Index methodology and summary ratings for transmission and distribution assets is provided in Appendix N;
- ***Customer reliability:*** BC Hydro also reviews reliability statistics, identifies assets with poor performance and develops solutions for improvement. For example, the worst performing distribution feeders are studied to determine the areas of under-performance, conduct root cause analysis and assess solutions for future investment to improve reliability;

- ***Regulatory Requirements:*** BC Hydro also evaluates the compliance of assets with the regulatory requirements of the *Workers Compensation Act*, the B.C. *Wildfire Act* and environmental laws as well as the requirements of Mandatory Reliability Standards, Measurement Canada, and Transport Canada; Compliance is addressed within the requirements of each regulation;
- ***Load and Energy Forecasts:*** BC Hydro assesses the capability of the transmission and distribution system to meet expected peak demand and accommodate forecast load and generation additions; and
- ***Other Risks:*** BC Hydro assesses the potential severity and likelihood for a range of risks including safety, seismic, environment, fire, extreme weather, and security. High risks, as determined by BC Hydro's enterprise-wide framework for capital prioritization, are considered for remediation. The enterprise-wide framework is discussed further in section 6.3.4.

6.4.4.2 Step 2 – Determine the Scope of the Studies

Second, BC Hydro determines the scope of studies to assess identified needs. These studies integrate multiple needs, impacting the same parts of the system, within a similar timeframe, so that they proceed through the planning process together.

In this step, identified needs are reviewed by regionally-focused cross-functional teams to determine integration opportunities. These teams consider how needs relate to each other as well as the required timelines for remediation and the risks of delay. These reviews may result in certain needs being addressed through province-wide work programs or deferred due to low risk.

Third-party interconnection requests are not typically considered for integration with other needs. These projects normally proceed individually through their respective mandated and schedule-driven processes.

6.4.4.3 Step 3 – Undertake Studies

Third, BC Hydro studies identified needs in detail and identifies technically feasible alternatives to remediate these needs through projects or work programs. There are three types of studies: Area Plans, Substation Asset Plans and Asset Class Strategies. The studies vary from a few weeks to several years depending on the complexity of the needs and alternatives.

- ***Area Plans:*** Area Plans are specialized technical planning studies to identify alternatives to address needs related to issues such as load growth, new generation and system reliability. The Downtown Vancouver Electric Supply Plan and the Squamish Area Reinforcement Study are examples of integrated Area Plans;
- ***Substation Asset Plans:*** Substation Asset Plans are developed for substations with multiple pieces of equipment that require replacement within a similar timeframe. The Barnard Substation Asset Plan is an example of a substation asset plan; and
- ***Asset Class Strategies:*** Asset Class Strategies determine the appropriate remediation approach for each asset class. Asset Class strategies include replacing the asset or continuing to perform maintenance on the existing asset.

Summaries of Area Plans, Substation Asset Plans and Asset Class Strategies are provided in Appendix K.

6.4.4.4 Step 4 – Annual Capital Planning Review

Fourth, as part of the annual capital planning process, BC Hydro undertakes a review of planned investments. Investments are reviewed by cross-functional teams to align investments across the portfolios. In addition, investments are reviewed to check that the data quality is sufficient and the investments are appropriately prioritized and timed. These investments are then submitted into the Integrated Power System Portfolio Management process, as described in section 6.4.5 below.

6.4.5 Integrated Power System Portfolio Management Brings Planned and Ongoing Projects and Programs into One Portfolio

Once a year, forecasts for the planned generation, transmission and distribution projects and programs, developed through the bottom-up processes described in the preceding sections, are brought together with projects and programs already being delivered. This consolidation of a single Power System capital investment portfolio begins the final stage of the preparation of the Power System Capital Plan.

The enterprise-wide framework for capital prioritization, described in section 6.3.4, is used to categorize each investment in the initial portfolio, and assign risk to the deferral of the investments. Where labour resources have been identified as a risk to the delivery of the portfolio, the demands on the labour pool to deliver each investment are assessed and the availability of those resources are estimated.

In the most recent capital planning process, the prioritization of the portfolio for fiscal 2020 to fiscal 2024 was managed within the established level of capital investment, as discussed in section 6.3.2. This review considered the resource availability of various labour groups, including Communications, Protection and Control Technologists as well as Distribution Designers. While in previous planning cycles, the availability of Communications, Protection and Control Technologists has constrained BC Hydro's ability to include certain investments in its portfolio, recent measures have prevented the undue delay of higher risk investments. For example, BC Hydro has increased the availability of these labour resources through improved contract management which has diversified the external suppliers used to perform this work. As a result, in this most recent capital planning cycle, labour resource constraints did not trigger the deferral of investments in the fiscal 2020 to fiscal 2024 period at the portfolio level.

The final step of the process is to review the Power System capital investment portfolio to determine the highest priority projects and programs within the labour and financial constraints that have been identified. These results are then reviewed with the leadership team of the Integrated Planning Business Group. This provides an opportunity for senior leaders to offer input and to align the portfolio business objectives. Once endorsed by the Integrated Planning leadership team, the Power System Capital Plan is submitted into the Enterprise Capital Planning process, which is described in section 6.3.4.

6.4.6 Planning and Delivery Processes Are Well Integrated

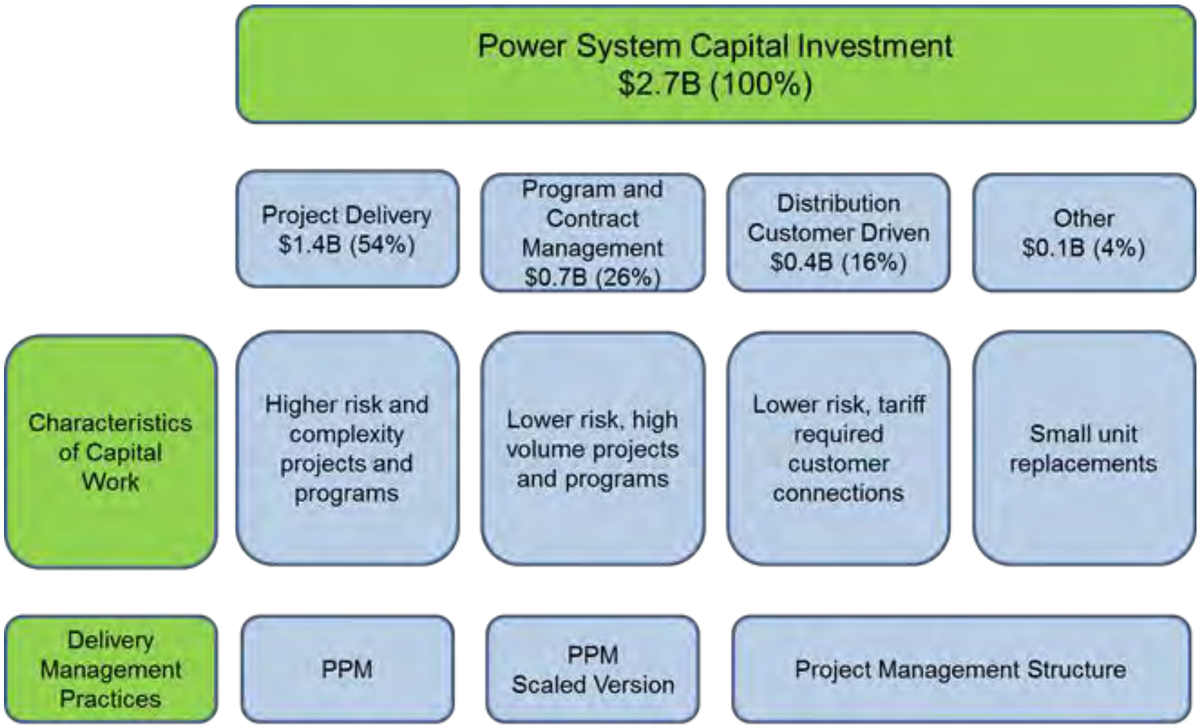
This section provides an overview of the collaboration and integration between planning and delivery through the annual capital planning process, work planning and the release of projects and programs to the KBUs responsible for delivery.

Investments associated with the Power System are delivered by three different KBUs: Project Delivery, Program and Contract Management and Distribution Design and Customer Connect. The processes followed by each KBU are adapted to suit the types of investment that they are responsible for delivering.

Large and complex investments generally require more rigorous delivery processes, involve a larger and broader group of internal and external stakeholders, and call for a high level of oversight and governance. Smaller projects or higher volume replacements of less complex assets require a scaled approach. Therefore, BC Hydro utilizes a range of delivery management practices to suit the range of investments that need to be delivered.

Figure 6-12 below provides a summary of the Power Systems capital investments to be delivered by each KBU for fiscal 2020 to fiscal 2021 as well as the delivery management practice used to deliver those investments.

Figure 6-12 Summary of Power Systems Capital Investments by Delivery KBU for Fiscal 2020 to Fiscal 2021



6.4.6.1 Established Process Allows Early Identification of Issues and Resources

BC Hydro has an established process for early identification of issues and resources, so that work is assigned to the correct KBU with the appropriate delivery process for the nature of the investment and with resources to complete the work.

During the annual capital planning process to develop the capital plan for the Power System, the planning and delivery KBUs collaborate to:

- Consider labour resource availability, and validate that the Power System capital plan can be delivered with available internal and external resources;
- Determine the delivery model and assign capital investments to the appropriate KBU for delivery, considering factors such as:
  - Asset types and characteristics;

- The size, scope, complexity, duration and costs of the projects or programs; and
- The number of internal and external stakeholders that need to be involved.

- Review the larger and more complex projects that are proposed to be delivered by the Project Delivery KBU. This includes a review of the problem statement, possible alternatives, project scope, project duration, delivery risks and potential operational constraints.

6.4.6.2 Integrated Planning Remains Involved Throughout the Delivery Process

After the completion of the annual capital planning process, BC Hydro begins work planning. This involves reviews of specific investments targeted for release in the next fiscal year. The planning and delivery KBUs review the scope of planned capital investments in greater detail and consider the portfolio of planned work as well as investments already underway, to determine the appropriate time to start new work.

After work planning is complete, capital investments are prepared for release to the appropriate KBUs for delivery. This step includes final planning reviews and required financial approvals to initiate the work.

Capital investments to be delivered by the Project Delivery KBU are released on a quarterly basis to respond to changing project and resource load conditions that may require the timing of work to be adjusted. This quarterly release plan is reviewed regularly to confirm that adequate resources are available prior to project release. Capital investments to be delivered by the Program and Contract Management KBU and the Distribution Design and Customer Connections KBU are typically released on an annual basis, prior to the start of the fiscal year. After planned capital investments have been released to the appropriate delivery group, the Integrated Planning Business Group continues to be involved throughout the delivery process and participates in key decisions and accountability meetings as the initiating group representatives.

6.4.7 Project Delivery KBU Uses the Program and Portfolio Management System to Deliver Larger, More Complex Projects

The Project Delivery KBU is responsible for delivering larger, more complex Power System projects. Approximately 54 per cent of the planned capital investments in the Power System for fiscal 2020 to fiscal 2021 will be delivered by the Project Delivery KBU.

A rigorous project delivery process is critical to delivering large or complex projects effectively. The Project Delivery KBU uses the Project and Portfolio Management System (**PPM**) system for consistent management of project risk, scope, schedule and cost.

6.4.7.1 Program and Portfolio Management System is Consistent with Industry Standards

PPM is BC Hydro's framework to manage engineering and construction projects that require engineering and/or project management services. It provides a consistent approach to minimize delivery risks. PPM practices are consistent with industry standards such as the Project Management Institute's Project Management Book of Knowledge and the Association for the Advancement of Cost Engineering International Recommended Practices. PPM is structured as a Quality Management System, consistent with the principles of ISO 9001, 2008 Quality Management Systems - Requirements.

There are three key components to the PPM system: practices, tools and learning. These components are described further in the sub-sections below.

6.4.7.2 PPM Practices Standardize the Management of Large, Complex Projects

All capital projects managed within PPM are delivered using a standard set of defined practices. BC Hydro's six defined Project Delivery Practices are:

- **Project Management** - The objective of this practice is to increase efficiency and discipline in our work by providing a consistent framework for delivering projects and producing associated documentation. Application of these practices increases safety for the public and employees, the quality of work delivered through the projects and our future capacity by sharing knowledge and lessons learned;

- **Design** – This practice aims to increase efficiency and consistency in engineering design to provide facilities and equipment that are fit for purpose and will operate safely, reliably, economically and in an environmentally responsible manner, over the asset lifetime;
- **Construction and Contract Management** - This practice documents the services that we apply to construction projects, programs, and portfolios to achieve project objectives with regards to safety, security, environment, project scope, quality, schedule, and cost;
- **Indigenous Relations** – This practice manages consultation and engagement with First Nations on BC Hydro's capital projects;
- **Procurement** - The objective of this practice is to increase efficiency, consistency and quality in major capital project procurement by providing a framework for producing and delivering contracts that meets project requirements; and
- **Regulatory, Environment, Social Issues and Properties** - The purpose of this practice is to support the delivery of the regulatory, environment, social issues and properties related services to capital projects by developing and maintaining processes, tools, templates and guides to successfully achieve project scope, schedule, quality and cost objectives. This supports regulatory compliance as well as conformance with BC Hydro's policies, strategic objectives and Statements of Strategic Intent.

In addition to the six Project Delivery Practices, PPM also includes Program Management and Portfolio Management Practices.

The specific objectives of the Program Management Practice are to:

- Integrate program management with other Project Delivery practices including portfolio management and project management;
- Provide a common approach to the management of programs within BC Hydro;
- Support the planning and delivery of programs, including objectives, outcomes and benefits; and
- Support program managers with processes, techniques and templates.

The Portfolio Management Practice aims to establish consistent standards to support effective management of portfolios of project, program, and work program expenditures across BC Hydro. In particular, portfolio management guides the creation of a Portfolio Delivery Plan that describes the optimal approach to delivery of the entire portfolio, considering aggregation and coordination of opportunities and risk responses.

The Portfolio Management Practice also supports development of a baseline for measuring actual performance of the Portfolio Delivery Plan against the identified targets. This performance measurement allows management to understand and make more informed decisions on the interactions between projects, programs and work programs, to identify potential problems or opportunities, and to make timely interventions.

Underlying all of the Project, Program and Portfolio Practices are four “global” Practices:

- Document and Records Management is responsible for defining the framework in which documentation and records are required and dealt with for portfolio, program and project delivery;
- Performance Management defines key performance indicators that are implemented to measure the project;

- Reporting provides background on reporting, its structure, the basics about the reporting process as well as what is required to develop quality reports; and
- Resource Management ensures that the correct resources are assigned to complete projects on schedule.

6.4.7.3 PPM Incorporates the Consistent Use of Technology in Project Management

BC Hydro’s PPM process uses technology solutions to manage project components. The following provides a high-level summary of these solutions and their application.

- There are two modules in the SAP system:
    - The Project Systems module provides a single system of record for work breakdown structures and financial data; and
    - The Business Warehouse module provides automated reporting on projects in the PPM process.
- The Primavera system has three components:
    - P6 software provides cost and schedule forecasts for each project;
    - Unifier is a contract management tool that is linked to the project schedules in Primavera P6; and
    - Primavera Risk Analysis performs schedule risk analysis on complex projects with a higher degree of risk.
- The PPM Workspace system (Microsoft SharePoint) provides document management functions.
- The PPM Information Centre is a web-based system that provides a record of the PPM practices.

6.4.7.4 PPM Includes a Learning Component to Support Best Practices

The Learning component of PPM involves the development of BC Hydro's staff and the sharing of knowledge and experience. This is achieved through:

- **PPM Information Centre** – A website of learning and reference materials associated with Project and Portfolio Management;
- **Community of Practice** – Team sessions for all BC Hydro staff and contractors facilitated by internal and external subject matter experts;
- **Communication Hub** – an online newsletter that provides role-specific, directed communications of changes that affect how we deliver PPM projects;
- **Learning Plans** - including role-based learning available online for Document Coordinators, Schedulers and Work Package Managers to provide easy access to role specific training information;
- **Career Development site** – career pathways and progression models based on Project Delivery roles;
- **Training Sessions** – BC Hydro hosts bi-weekly Community of Practice Learning events as well the International Project Management day, where internal and external presenters share their knowledge of best practices, lessons learned and provide an opportunity to network with others; and
- **Industry Organizations** – BC Hydro participates in industry groups to share Project Management best practices, including the Project Management Institute West Coast Chapter, Western Energy Institute, Canadian Electric Utility Project Management Network and Utility Peer Group (consisting of North American utilities).

6.4.7.5 Project Delivery Lifecycle Involves Staged Refinement of Scope and Estimates and Gate Approvals

The delivery lifecycle of PPM projects is divided into four phases: Initiation, Identification, Definition and Implementation. Each phase is further divided into various stages. The lifecycle represents a staged approach to project definition and gate approvals.

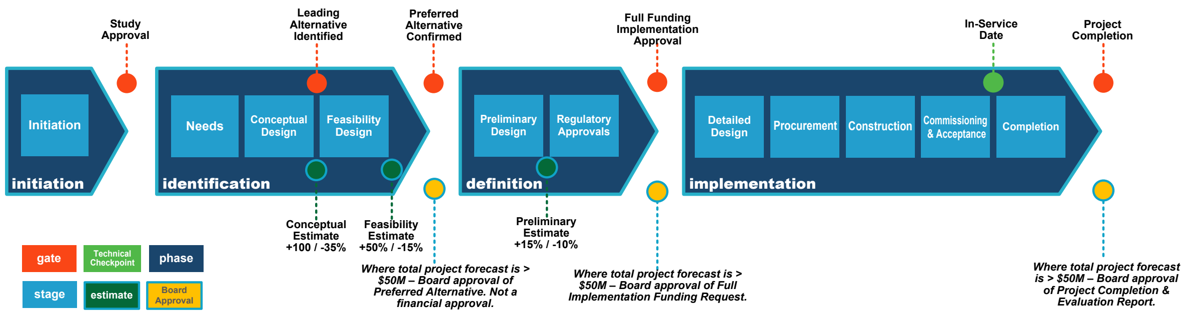
As projects move through this process, they become more defined. The increased level of definition allows for updated cost estimates to be developed. Cost estimates are provided at completion of the following stages:

- Conceptual Design: This estimate has an expected accuracy range of +100 per cent and -35 per cent;
- Feasibility Design: This estimate has an expected accuracy range of +50 per cent and -15 per cent; and
- Preliminary Design: This estimate has an expected accuracy range of +15 per cent and -10 per cent.

Gate approvals also occur at various points of the project lifecycle. Each gate is a formal approval point where key information on project cost, schedule, scope, procurement and risk is presented to the Gate Board. Further information on Gate approvals is provided in section 6.4.7.10 below.

Figure 6-13 below provides a summary of the project delivery lifecycle. The Gates following each phase of the project lifecycle are shown as red circles, and approvals by the Board of Directors are shown in yellow circles. These project lifecycle phases and stages are non-discretionary.

Figure 6-13 PPM Project Lifecycle



The following sections describe the four phases of the PPM Project Lifecycle: Initiation, Identification, Definition and Implementation.

6.4.7.6 Phase 1 in PPM Project Lifecycle: Initiation

The Initiation Phase begins by establishing an issue, risk or opportunity to be addressed through a planned capital project. A Study Approval Gate occurs at the end of the Initiation phase to conclude this phase and provide approval to proceed to the Needs and Conceptual Design Stages of the Identification Phase. This Gate represents the release of the project from Integrated Planning to Project Delivery. A Project Manager is then assigned to manage the specific project through to completion.

6.4.7.7 Phase 2 in PPM Project Lifecycle: Identification (+100/-35 per cent)

The Identification Phase consists of three stages: Needs, Conceptual Design and Feasibility Design.

- **The Needs Stage** clarifies and validates the risk, issue or opportunity to be addressed and develops a selection of high-level solution alternatives for further consideration. In this stage, an initial Work Breakdown structure, Statement of Objectives and Project Plan are developed. This includes the development of documents and systems to support the project delivery process throughout the lifecycle of the project;

- **The Conceptual Design Stage** analyzes the alternatives developed in the Needs stage and selects the alternatives to be carried forward into the Feasibility Design stage. For each selected alternative, an overall concept plan is developed including preliminary drawings of major project features, a general definition of equipment and system requirements and an overview of First Nations, stakeholder, environmental, socio-economic and procurement considerations. The selected alternatives are refined to eliminate the alternatives that do not meet the project objectives and to recommend a Leading Alternative that is technically and economically feasible and should be considered further. The main deliverable in the Conceptual Design stage is a business case which describes the alternatives considered, the methodology for evaluating those alternatives and the recommended Leading Alternative. The recommended Leading Alternative is confirmed through the Leading Alternative Identified Gate. Once this approval is provided, a conceptual design level estimate is prepared, with an expected accuracy range of +100 per cent and -35 per cent; and
- **The Feasibility Design Stage** conducts the investigations and analysis required to confirm that the Leading Alternative should be selected as the Preferred Alternative, to be carried forward to the Preliminary Design Stage of the Definition Phase. This analysis may include field and laboratory investigations as well as further evaluation of First Nations interests, environmental and other non-technical considerations. This analysis provides the required detail to prepare plans for the Definition Phase and to develop a feasibility design level estimate, with an expected accuracy range of +50 per cent and -15 per cent. At the end of the Feasibility Design stage, an updated business case is developed and a Preferred Alternative Gate is held to confirm the Preferred Alternative. After the Gate, for projects with an Estimate at Completion greater than $50 million, the Executive Team reviews the Preferred Alternative before it proceeds to the Board of Directors for approval.

6.4.7.8 Phase 3 in PPM Project Lifecycle: Definition (+15/-10 per cent)

The Definition Phase defines the major project components in sufficient detail to develop a Preliminary Design cost estimate with an accuracy range of +15 per cent and -10 per cent. In this phase, implementation funding and any required regulatory authorizations are obtained. In addition, the Project Manager verifies that sufficient input has been received from First Nations via engagement and/or consultation as well as from internal and external stakeholders. To complete the Definition Phase, the Statement of Objectives, the Project Plan for the Implementation Phase and the final Business Case are examined through the Full Funding Approval Gate. This Gate confirms that the risks associated with executing the work in the Implementation Phase are well managed and acceptable, before proceeding to that phase. After the Gate, for projects with an Estimate at Completion greater than $50 million, the Executive Team reviews the Full Funding Approval request before it proceeds to the Board of Directors for approval. All projects greater than $100 million are reviewed and approved by the BCUC.

6.4.7.9 Phase 4 in PPM Project Lifecycle: Implementation

The Implementation Phase consists of five stages: Detailed Design, Procurement, Construction, Commissioning and Acceptance, and Completion.

- The Detailed Design stage is the final stage in the design process. This stage refines the Preferred Alternative so that it can be represented in a manner that allows work to be procured, manufactured and constructed in accordance with objectives, requirements, industry standards and accepted practices. Drawings and specifications are prepared in this stage and depending on the scale of the project, several design reviews may be required.
- The Procurement Stage initiates the sourcing process and issues tenders or requests for bids and proposal documents. In this stage, contracts are awarded for the supply, installation and construction of required work.

- The Construction Stage develops, manufactures, supplies, installs and constructs the required work in accordance with the contract specifications, drawings, and criteria.
- The Commissioning and Acceptance Stage tests and commissions the constructed facility or component in accordance with the prescribed criteria. Once the facility or component has been successfully commissioned, accepted and is fit for service, operational authority is transferred from the Project Delivery KBU to the appropriate KBU within the Operations Business Group.
- During the Project Completion Stage, the Project Delivery KBU provides a list of post-project commitments and conditions of permits, approvals and agreements to the responsible KBU within the Operations Business Group. The final deliverable in this stage is the project completion and evaluation report. Once this report is accepted, the project is classified as complete.

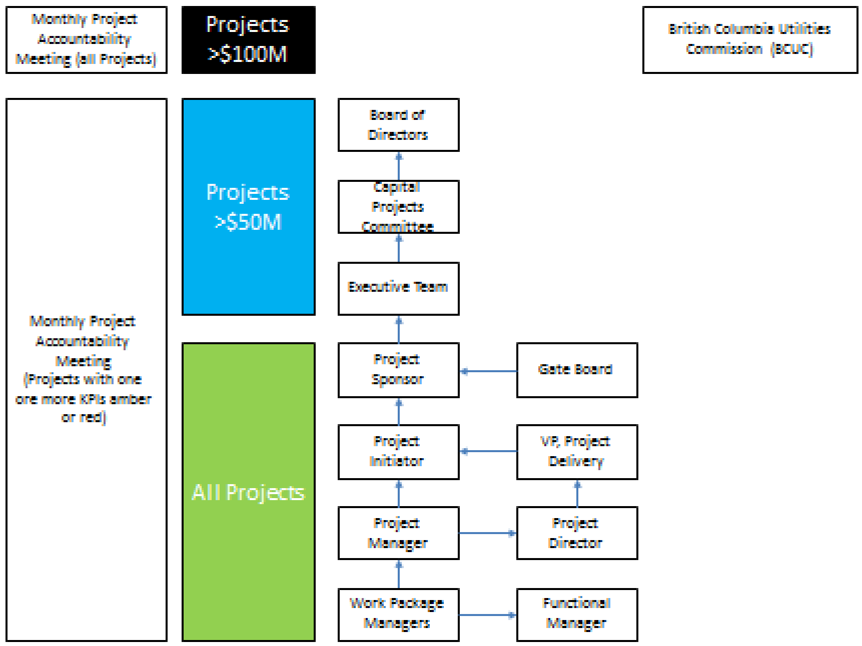
6.4.7.10 Project Delivery Roles and Responsibilities are Well Defined

Another important attribute of our project delivery process is that roles and responsibilities are well-defined in advance. The process we employ streams projects based on their size and complexity, with additional levels of oversight for complex or higher risk projects.

BC Hydro deploys a matrix organization for resourcing and managing people assigned to capital investments delivered by the Project Delivery KBU. This means that staff are assigned to a project from various KBUs across the company to perform the required roles. Staff can be assigned to a project on a full-time or part-time basis and are accountable to the Project Manager for all project related work and decisions. The Project Manager is responsible for the day to day direction and decisions on the project. The KBUs that assign staff are responsible for setting standards, process and practices for their staff, conducting training on those practices and processes and for providing collegial support, approval of expenses and performance management.

Figure 6-14 below illustrates the project governance structure for projects delivered by Project Delivery.

Figure 6-14 Project Delivery KBU - Project Governance Structure



The following provides a summary of the various roles within this governance structure;

- ***Work Package Manager:*** The Work Package Manager is responsible and accountable for the planning and delivery of the Work Package within the approved scope, cost, and schedule as detailed in the Work Package Agreement. The Work Package Manager works with the Project manager and related Work Package Managers to create and develop the Work Package agreement (an element of the project scope);
- ***Functional Manager:*** The Functional Manager is responsible for the review of the Work Package agreement with the Work Package Manager to assess expectations for resource needs and review assumptions, scope, deliverables, milestones and activities related to the Work Package Agreement;

- ***Project Manager:*** The Project Manager is responsible for leading the project team to complete the objectives of the project. The Project Manager is accountable to the Project Initiator to determine the need, justification and objectives (scope, schedule and cost) of the project as well as to the Project Delivery Director for the delivery of the project against approved objectives and in accordance with approved policy and practice;
- ***Project Delivery Director:*** The Project Delivery Director is accountable to the Vice President of Project Delivery and is responsible for the execution of the projects in their portfolio against approved objectives and in accordance with approved policy and practice. The Project Delivery Directors chair the gate board meetings for projects with a cost of less than $10 million;
- ***Vice President, Project Delivery:*** The Vice President, Project Delivery is responsible for the delivery of the projects assigned to the Project Delivery KBU and is accountable to the Senior Vice President of Capital Infrastructure Project Delivery. The Vice President, Project Delivery chairs the gate board meetings for projects with a cost of greater than $10 million;
- ***Project Initiator:*** The Project Initiator is the person with the authority to initiate work and is responsible for defining the work through the Statement of Objectives and justifying the work through the Business Case. The Project Initiator is also responsible for securing all required financial approvals. The Project Initiator sets project requirements which are then translated by the Project Manager into project scope, schedule and cost. The Project Initiator is accountable to the Project Sponsor for the definition and justification of the project; and
- ***Project Sponsor:*** The Project Sponsor supports the success of the project, by approving the project and liaising with senior management. At Gate board meetings, the Project Sponsor receives and considers Gate board recommendations to decide whether to approve key project decisions.

The following committees provide oversight of projects and endorsement of project funding requests:

- **Project Accountability Meetings:** BC Hydro conducts monthly Project Accountability Meetings to allow the Project Manager to update Gate Board members and internal stakeholders on the ongoing status of each project and provide a forum for participants to ask questions and deliver input and guidance. All projects with forecast capital costs greater than $100 million and projects under $100 million where one or more Project Key Performance Indicators are amber or red are reviewed monthly. The discussion at these meetings includes items such as project schedule, cost, scope, safety, operations, Indigenous relations, stakeholder engagement and project risks.

Table 6-8 below identifies Project Accountability Meeting attendees.

Table 6-8 Project Accountability Meeting Attendees

Senior Vice President, Integrated Planning	Senior Vice President, Capital Infrastructure Project Delivery
Senior Vice President, Safety	Executive Vice President, Operations
General Manager, Engineering	Vice President, Project Delivery (*Chair*)
Director, Stations Asset Management	Director, Indigenous Relations
Director, Dam Safety	Director, Environment
Director, Line Asset Planning	Director, Properties
Director, Interconnections	Director, Line Field Operations
Director, Finance	Director, Stations Field Operations

- **Gate Board Meetings:** Depending on the stage of the capital project, the project's estimated cost, scope, alternatives assessment, and implementation plans are subject to endorsement by a review at a Gate Board Meeting, before a funding request is approved. The Gate Board reviews the project to determine if it is ready to progress to the next stage of its lifecycle. In addition to funding and stage progression approvals, these meetings provide an avenue for discussions with, and guidance from, key delivery partners on the status of projects and potential future issues.

As shown in Table 6-9 below, there are two types of Gate Board Meetings, depending on the cost of the capital project:

Table 6-9 Types of Gate Board Meetings

Meeting Type	Capital Project Size
Major Gate Meeting	Projects ≥ $10 million
Non- Major Gate Meeting	Projects < $10 million

Table 6-10 below identifies major and non-major Gate members.

Table 6-10 Major and Non-Major Gate Board Members

Major Gate Board Members	Non-Major Gate Board Members
Executive Vice President, Operations	Project Director(s) (*rotating chair*)
Senior Vice President, Integrated Planning	Manager, Project Environmental Risk Management
Senior Vice President, Capital Infrastructure Project Delivery	Manager, Indigenous Relations
Senior Vice President, Safety	Director, Stations Asset Planning
Vice President, Project Delivery (*Chair*)	Director, Dam Safety
Director, Environment	Director, Stations Field Operations
Director, Indigenous Relations	Director, Line Asset Planning
Director, Stations Asset Management	Director, Line Field Operations
Director, Dam Safety	Director, Interconnections
Director, Stations Field Operations	General Manager, Engineering
Director, Line Asset Planning	Finance Manager, Business Planning
Director, Line Field Operations	Capital Safety Manager
General Manager, Engineering	
Director, Finance	
Director, Properties	

The following additional governance roles are performed for all projects with a forecast cost greater than $50 million:

- ***Executive Team:*** The Executive Team reviews the project to determine if the project is the appropriate response to the identified risk, issue or opportunity.

This review occurs at the end of the Identification Phase. The Executive Team also conducts a review at the end of the Definition Phase to determine whether the project is ready to proceed to the Implementation Phase, given the assessment of residual risks. This review supports the recommendation for approval to the Board of Directors;

- ***Capital Projects Committee:*** The Capital Projects Committee is one of the standing committees of BC Hydro's Board of Directors. This committee assists the Board of Directors in fulfilling its obligations and oversight responsibilities related to the delivery of capital projects. Specifically, this includes, but is not limited to, dam safety, the execution of long-term capital plans and budgets, project oversight and relationships with First Nations. For capital projects with a forecast cost greater than $50 million, the Committee reviews the status of capital projects during the Identification and Definition phases, reviews and recommends the preferred alternative for approval by the Board of Directors, following the completion of the Identification Phase, and reviews and recommends financial approval by the Board of Directors, before the start of the Implementation Phase. When making its recommendations to the Board of Directors, the Capital Projects Committee reviews potential impacts to Aboriginal rights and title as well as planned mitigations and considers whether, in moving forward with a project, BC Hydro's consultations with First Nations uphold the honour of the Crown. The Capital Projects Committee meets quarterly in conjunction with the Board of Directors Meeting; and
- ***Board of Directors:*** BC Hydro's Board of Directors is appointed by and accountable to the B.C. Government. The Board of Directors is responsible for safeguarding BC Hydro's resources by approving annual operating and capital budgets as well as individual capital projects with a forecast cost greater than $50 million. For these projects, BC Hydro has established processes in place to facilitate Board of Directors review and approval of the preferred alternative, following the completion of the Identification Phase, and financial approval, prior

to the start of the Implementation Phase. When considering approval, the Board of Directors reviews potential impacts to Indigenous peoples as well as planned mitigations and ensures that in moving forward with a project, the honour of the Crown is maintained.

In addition to the roles and responsibilities described above, the BCUC provides independent third-party review and approval of the need for projects greater than $100 million or of significant public interest, unless a project has been exempted by government regulation. The BCUC also reviews the status of projects through quarterly or semi-annual progress reporting, and may undertake a prudency review of projects, once implementation is complete.

6.4.8 We Use a Simplified Framework for Routine Power System Investments

The Program and Contract Management KBU is responsible for delivering less complex and repetitive Power System capital investments on BC Hydro's power system. The KBU is the single point of contact for the annual delivery of the maintenance and small capital investment portfolio that is developed and optimized by the Integrated Planning Business Group.

Approximately 26 per cent of planned capital investments in the Power System for fiscal 2020 to fiscal 2021 will be delivered by Program and Contract Management.

When the annual maintenance and small capital investment portfolio is received from the Integrated Planning Business Group, the Program and Contract Management KBU develops annual program and project delivery plans in collaboration with the KBUs in the Integrated Planning and Capital Infrastructure Project Delivery Business Groups. This includes consideration of First Nations and environmental issues. Internal resource commitments to deliver the work are obtained from the Engineering, Distribution Design and Customer Connect, Line Field Operations, Stations Field Operations and Construction Services KBUs. Contracting plans are then developed to deliver the balance of the portfolio. Internal

FTEs are used to deliver a significant volume of the small capital work, with external contractors being used to provide scalability due to fluctuations in demand. Additional discussion on how Program and Contract Management delivers work is provided in Chapter 5C, section 5C.4.

The capital investments delivered by Program and Contract Management are typically “like for like” replacements of assets or system upgrades that are based on pre-defined design standards, developed by BC Hydro’s Engineering KBU. Examples of capital investments delivered by the Program and Contract Management KBU include duct-bank construction, some end-of-life equipment replacement and overhead line relocations within an existing or public right-of-way. These investments are routine in nature, have a lower risk profile and require minimal, if any acquisition of property or rights of way. The standardized nature of these investments means that there are limited, if any alternatives to evaluate. Standard procedures are established to select the most feasible alternative when required.

These investments generally do not require specific equipment procurement and the required materials are typically inventoried by BC Hydro’s Materials Management department. When specialized services, equipment or materials are required, standing blanket services contracts or master purchasing agreements are used. Work is completed through unit-based contracts with external contractors.

The Program and Contract Management KBU applies a simplified version of the PPM practices that is suited to the lower complexity of the projects it delivers. For program investments that involve standardized units of work, the Program and Contract Management KBU applies simplified work management processes.

6.4.9 We Use a Standardized Process for Routine Customer Driven Work

The Distribution Design and Customer Connections KBU is responsible for work related to customer requests for new or upgraded connections to BC Hydro's distribution system. This KBU provides technical design services and project management for customer driven new connections work, under 5 MW in size. More complex projects over 5 MW or over $2 million in cost are managed by Program and Contract Management, with Distribution Design and Customer Connections providing design services. Approximately 16 per cent of the planned capital investments in the Power System for fiscal 2020 to fiscal 2021 will be delivered by the Distribution Design and Customer Connections KBU.

The Distribution Design and Customer Connections KBU designs to standards, with engineering support where required, and follows a project management structure that involves standardized work order packages, with environmental, archeological, safety and job planning processes and checklists. This simplified process enables project cycle times to align with customer requirements.

The Distribution Design and Customer Connections KBU issues approximately 5,000 work orders for new customer connections and 10,000 work orders for internal distribution growth and sustaining capital work programs each year. These work orders require design work and project coordination. A dedicated Express Connections Contact Centre within this KBU issues 35,000 express service orders per year. Express service orders are very simple customer connections which do not require design work.

While the Distribution Design and Customer Connections KBU plans for customer connections at a system level, individual customer connection projects depend on actual customer requests. Therefore, these projects are driven by customer timelines and are not planned in detail. Program volumes and characteristics are forecast based on historical trends. The staffing model for the Distribution Design and Customer Connections KBU includes full-time regular designers, full-time temporary designers and contractor engineering resources to provide flexibility and to balance internal work program and customer program demands so that customer requests are prioritized for delivery to the agreed in-service dates.

6.4.10 Financial Approval Policies and Procedures Apply to All Capital Investments

BC Hydro has well established Management and Accounting Policies (**MAPP**) and Procedures and Financial Approval Authority Policy (**FAAP**) that set funding approvals required for capital investments through each phase of the project lifecycle. These approval requirements and processes have been developed to balance financial controls with operational efficiency, based on the nature and risk of the capital investments. The policies and procedures apply to all groups delivering BC Hydro's capital investments.

6.4.10.1 Company-Wide Approval Policies Are Documented

The policies that govern capital investment approvals are primarily included in:

- Management and Accounting Policies and Procedures 1.2.31A (Expenditure Authorization Requirements Policy);
- Management and Accounting Policies and Procedures 1.2.3B (Expenditure Authorization Requirements Procedure); and
- Management and Accounting Policies and Procedures 1.2.1B.2 (Financial Approval Authority Procedure).

The required financial approval processes set out in these documents depend on the type of capital investment. Capital investments are categorized into the following four main categories for financial approval processes:

- Phased Capital Projects;
- Non-Phased Capital Projects;
- Recurring Capital Investments; and

- Expenditure Authorization Request Exempt Capital Investments.

The financial approval processes for each category are discussed further in the sections below.

6.4.10.2 Phased Capital Projects Require Phase-by-Phase Funding Approval

For capital projects which are delivered using PPM phases, funding approval is required prior to the commencement of work for that stage or phase. Typically, funding is approved only for the next stage or phase once the required work for the prior stage or phase has been completed. The financial approver level is dependent on the stage or phase as well as the funding amount being requested. For projects that meet the BCUC thresholds for Certificate of Public Convenience and Necessity (**CPCN**) and section 44 reviews, applications are generally submitted to the BCUC during the Definition Phase.

Table 6-11 below provides information on the funding approval process for phased capital projects, delivered by the Project Delivery KBU and Technology.

Table 6-11 Funding Approval Process for Phased Capital Projects (Project Delivery KBU)

Phase	Primary Budget	Estimate Accuracy Level	Funding Approval Documents	Project Approvers and Finance Review	Basis of Approval	FAAP Approver
Identification Phase (Needs Stage)	O&M (CPI)[304]	N/A	• Annual Release Plan from Capital Plan • Maximum request is generally $200,000	• Project Release Committee • No Finance Review	Amount requested	Director Project Delivery
Identification Phase (Conceptual Design stage)	O&M (CPI)	End of Stage provides +100% / -35%	• Statement of Objective (**SOO**) • If over $2M, business case and Expenditure Authorization Request (**EAR**) Form also prepared	• Project Sponsor • Project Initiator • No Finance Review unless requested amount is more than $2M	Based on cumulative O&M amount requested	Chief Operating Officer (**COO**): Up to $50M Others: 25% of FAAP Planning limit
Identification Phase (Feasibility Design Stage)	Capital	End of Stage provides +50% / -15%	• SOO • Business Case • EAR Form	• Gate Board • Project Sponsor • Project Initiator • Finance Review required	Based only on amounts requested going forward	COO: Up to $50M Others: 25% of FAAP Planning limit
Definition Phase	Capital	End of Stage provides +15% / -10%	• SOO • Business Case • EAR Form	• Gate Board • Project Sponsor • Project Approver • Finance Review required	Based on cumulative amount requested starting from Feasibility Design Stage	COO: Up to $50M Others: 25% of FAAP Planning limit
Definition Phase with Partial Implementation Phase costs (not including construction)	Capital	End of Stage provides + 15% / - 10%	• SOO • Business Case • EAR Form	• Gate Board • Project Sponsor • Project Initiator • Finance Review required	Based on cumulative amount requested starting from Feasibility Design Stage	COO: Up to $50M Others: 25% of FAAP Planning limit

304 CPI refers to Capital Project Investigation cost.

Phase	Primary Budget	Estimate Accuracy Level	Funding Approval Documents	Project Approvers and Finance Review	Basis of Approval	FAAP Approver
Partial Implementation Phase costs including construction	Capital	N/A	• SOO • Business Case or CPCN if applicable • EAR Form	• Gate Board • Project Sponsor • Project Initiator • Finance Review required	Based on cumulative amount requested starting from Feasibility Design Stage	Ultimate FAAP approver for total project estimate
Implementation Phase	Capital	N/A	• SOO • Business Case or CPCN if applicable • EAR Form	• Gate Board • Project Sponsor • Project Initiator • Finance Review required	Based on cumulative amount requested starting from Feasibility Design Stage	Ultimate FAAP approver for total project estimate

Table 6-12 below provides information on the general funding approval process for phased capital projects delivered by other KBUs.

Table 6-12 Funding Approval Process for Phased Capital Projects (Projects Delivered by Other KBUs)

Phase	Primary Budget	Estimate Accuracy Levels	Approval Documents	Project Approvers and Finance Review	Basis of Approval	FAAP Approver
Identification	O&M	N/A or Various	• SOO or business case or equivalent • EAR form (Technology)	• Business group dependent • Finance Review dependent on amount requested and type of capital	Amount requested or based on Total Project Estimate (Technology)	COO: Up to $50M Others: 25% of FAAP Planning limit
Definition	Capital	Various	• Business Case • EAR Form	• Business group dependent • Finance Review required	Cumulative amount being requested or based on Total Project Estimate (Technology)	COO: Up to $50M Others: 25% of FAAP Planning limit
Implementation	Capital	Various	• Business Case • EAR Form	• Business group dependent • Finance Review required	Total Project Estimate	Ultimate FAAP approver for total project estimate

6.4.10.3 Non-Phased Capital Projects Require Business Case and Authorization

Non-Phased Capital Projects are capital investments that are not delivered using project phasing but are similar to a one-time capital investment. Examples include the purchase of new equipment or office furniture. For Non-phased capital investments over $0.5 million, an approved business case and Expenditure Authorization Request (**EAR**) form are required prior to any capital spending. These authorization documents are approved based on the total investment amount, in accordance with BC Hydro’s Financial Approval Authority Policy guidelines.

6.4.10.4 Recurring Capital Investments are Approved Annually

Recurring Capital Investments are generally completed each year, on an ongoing basis. This work is generally lower risk, involving like-for-like unit replacements, such as the annual distribution wood pole replacement program. These investments are authorized at the beginning of each fiscal year using the Recurring Capital Annual Expenditure Authorization Form.

6.4.10.5 Approved Work Orders Are Required for Low Cost Recurring Capital Projects

Expenditure Authorization Request Exempt Capital Investments are recurring capital projects with a low cost and high volume. Examples include work activities to connect distribution customers, which are required under the Electric Tariff and less than $1 million in cost. These investments are operationally approved through BC Hydro’s Work Order system. A business case is required for any projects with a forecast cost of more than $1 million.

6.4.11 Our Project Delivery Practices Reflect Many Recent Improvements

The project delivery practices outlined above reflect a number of improvements that have been introduced over the past several years. Specifically, BC Hydro has:

- Created a PPM Governance Committee that is accountable for the ongoing sustainment, ongoing realization of benefits and continuous improvement of the PPM System, including prioritizing and implementing enhancements;
- Created a PPM Practices Development and Review Committee that is responsible for development and continuous improvement of the PPM Practices program and its contents, and for developing and implementing corrective actions as required. The committee reviews and endorses proposals for changes to practices, or for new practices, and ensures that all practices remain aligned and consistent;
- Created a Project Acceptance Guide to document the process used by the Project Delivery KBU to deliver capital projects in compliance with operating orders and commissioning procedures;
- Implemented a lessons learned procedure to identify opportunities to improve the delivery and outcomes of future projects. These lessons learned generally result in recommendations to alter a practice or procedure, address a knowledge gap or improve project delivery tools. Lessons learned are documented throughout the project lifecycle and a lessons learned meeting is conducted prior to a project being placed into service;
- Established Field Review Sub-Practice and Procedures to set out the processes, roles, responsibilities and documentation requirements for project design and construction teams;
- Integrated specific geotechnical risk management into the Engineering Design Practice which requires site investigations to be conducted early in the project

delivery process and planned, as appropriate, throughout the phases of the project lifecycle.

- Conducted Project and Portfolio Management compliance audits on a quarterly basis to assess whether projects are following Project and Portfolio Management practices;
- Implemented “One Report” an online tool to standardize project reporting, reduce the level of effort required to extract project data and create reports and enhance the ability of internal stakeholders to view consolidated and detailed project information;
- Implemented the “Project and Portfolio Management Communication Hub”, a central location where Practice, Procedure and Process changes and updates are communicated to those responsible for the delivery of capital projects; and
- Implemented a Portfolio Risk Adjustment approach, recognizing that different phases in the project lifecycle have different levels of schedule and cost variability. Portfolio Risk adjustments are discussed further in section 6.4.12 below.
- Established the PPM Scaling and Project Scaling models so that projects can continue to follow PPM’s single standard practice while allowing the project team to modify the practices on a project by project basis to more efficiently and effectively deliver smaller and simpler projects. Further information is provided in Chapter 5, section 5.4.5.1.
- Established the Single Project Acceptance Process to support a consistent process for transferring BC Hydro assets from the Capital Infrastructure Project Delivery Business Group to the Integrated Planning Business Group (responsible for maintenance) and the Operations Business Group (responsible for operations).

6.4.12 Forecast Capital Expenditures and Additions are Reduced to Account for Uncertainties

BC Hydro has applied a Portfolio Risk Adjustment to its fiscal 2020 to fiscal 2021 forecast capital expenditures and additions to account for the uncertainty in the schedule and cost of projects. As discussed in sections 6.4.7.5 to 6.4.7.8, the accuracy of forecast capital additions increases with the level of analysis and information on project scope, schedule and cost. Therefore, the largest uncertainties are associated with projects that are currently in early stages of the project lifecycle as their scope, schedule and cost are not as well defined as projects that are in later stages.

The Portfolio Risk Adjustment amount is calculated using a Monte Carlo simulation. A probability distribution is determined, based on historical project delivery performance information. The calculated Portfolio Risk Adjustment amount represents the difference (by fiscal year) between the expected value of the simulated portfolio forecast and the sum of individual project forecasts in the baseline Capital Plan.

As discussed in Chapter 7, section 7.8.2, any differences between the forecast and actual amortization of capital additions are captured in the Amortization of Capital Additions Regulatory Account. This means that the actual amount recovered from ratepayers is ultimately based on the actual capital additions.

6.4.13 Generation Capital Expenditures and Additions

Compared to the forecast in the Previous Application, BC Hydro is forecasting relatively stable expenditures over the test period on average. Forecast capital additions are lower due to the anticipated completion of two major projects in fiscal 2019, as discussed further below.

6.4.13.1 Summary of Generation Capital Expenditures and Additions

The Generation assets actual and planned capital expenditures and capital additions for fiscal 2017 to fiscal 2021 are presented in Table 6-13 and Table 6-14 respectively, below.[305]

Table 6-13 Generation Actual and Plan Capital Expenditures Fiscal 2017 to Fiscal 2021

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Hydroelectric Generation								
Growth	20.0	21.2	2.4	10.2	0.7	4.0	3.2	-
Redevelopment / Rehabilitation	335.2	344.1	277.0	288.7	121.9	94.6	28.6	-
Dam Safety	57.0	89.2	94.7	71.0	124.3	51.8	68.8	130.0
Sustaining - Other	149.8	118.2	205.2	156.0	238.6	214.7	241.0	361.1
Total Hydroelectric Generation	561.9	572.7	579.4	525.9	485.5	365.2	341.7	491.1
Non Integrated Areas								
Growth								
Sustaining	7.7	5.7	7.2	8.3	6.6	5.4	8.7	5.0
Total Non Integrated Areas	7.7	5.7	7.2	8.3	6.6	5.4	8.7	5.0
Thermal Generation								
Growth						-	-	-
Sustaining	8.4	6.4	8.9	9.9	6.8	7.8	6.6	4.5
Total Thermal Generation	8.4	6.4	8.9	9.9	6.8	7.8	6.6	4.5
Total Gross Generation	578.0	584.8	595.5	544.1	499.0	378.4	357.0	500.6
Less: Portfolio Risk Adjustment	(28.0)	-	(59.0)	-	(74.0)	(8.5)	(11.9)	(65.2)
Total Generation	550.0	584.8	536.5	544.1	425.0	369.9	345.1	435.5
Less: Contribution in Aid	-	0.3	-		-	-	-	-
TOTAL	550.0	585.1	536.5	544.1	425.0	369.9	345.1	435.5

305 Capital expenditures and additions related to the Site C Project and the Waneta acquisition are excluded from the tables and discussion in this section. Fiscal 2017 and fiscal 2018 variances greater than $10 million are described in Appendix G. Additional information on Generation projects impacting the capital expenditures and capital additions presented is provided in Appendix I and Appendix J.

Table 6-14 Generation Actual and Plan Capital Additions Fiscal 2017 to Fiscal 2021

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Hydroelectric Generation								
Growth	26.6	24.2	0.9	9.6	0.2	(1.3)	2.7	-
Redevelopment / Rehabilitation	304.0	183.1	184.4	258.8	955.5	994.1	42.8	-
Dam Safety	57.4	27.7	66.9	80.8	87.5	79.1	49.3	44.4
Sustaining - Other	101.1	85.0	124.6	52.8	268.1	239.3	199.4	315.3
Total Hydroelectric Generation	489.1	320.0	376.8	402.0	1,311.3	1,311.2	294.1	359.7
Non Integrated Areas								
Growth								
Sustaining	8.3	8.2	6.9	4.1	4.2	5.4	7.9	5.8
Total Non Integrated Areas	8.3	8.2	6.9	4.1	4.2	5.4	7.9	5.8
Thermal Generation								
Growth						-	-	-
Sustaining	15.6	14.5	3.4	1.1	16.8	17.0	3.8	6.1
Total Thermal Generation	15.6	14.5	3.4	1.1	16.8	17.0	3.8	6.1
Total Gross Generation	513.0	342.7	387.1	407.2	1,332.3	1,333.5	305.8	371.5
Less: Portfolio Risk Adjustment						(30.2)	8.9	(74.6)
Total Generation	513.0	342.7	387.1	407.2	1,332.3	1,303.3	314.7	297.0
Less: Contribution in Aid	(0.3)	(2.0)	-			-		
TOTAL	512.7	340.7	387.1	407.2	1,332.3	1,303.3	314.7	297.0

6.4.13.2 Hydroelectric Generation Growth Projects - Expenditures and Additions Are Declining

Generation growth projects are to meet anticipated customer demand (Growth), or are improvements at existing generating stations to increase supply-side efficiency (also known as Resource Smart projects). Over the fiscal 2017 to fiscal 2021 period Hydroelectric Generation Growth capital expenditures and additions are generally decreasing due to the completion of the Mica Unit 5 and Unit 6 Additions project and the change in schedule of the Revelstoke Install Unit 6 project.

Table 6-15 below provides a summary of the fiscal 2020 to fiscal 2021 Growth capital additions and capital expenditures. More information on the project listed in Table 6-15 can be found in Appendix I, page 1, line 1 and Appendix J, page 1.

Table 6-15 Hydroelectric Generation Growth Projects - Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Growth				
G000594	Revelstoke Install Unit 6	-	-	0.6	-
	Projects & Programs Less than $5M	2.7	-	2.7	-
	Total Growth	**2.7**	**-**	**3.2**	**-**

Capital investments included in the Projects and Programs Less than $5 million line are related to project closeout costs for projects placed in-service in the prior test period.

6.4.13.3 Hydroelectric Generation Sustaining Projects Expenditures and Additions Are Declining

Generation redevelopment and rehabilitation projects are to redevelop facilities or significant elements of facilities that are at end of life.

Planned Redevelopment/Rehabilitation capital expenditures and additions over the test period have decreased from the fiscal 2017 to fiscal 2019 period due to the completion of a number of projects including the John Hart Generating Station Replacement and the Ruskin Dam Safety and Powerhouse Upgrade.

Some of BC Hydro's older facilities are relatively mature in their overall lifecycle and have a number of risks that need to be mitigated. These can include issues associated with the major generating equipment, auxiliary systems, buildings, water passages and large civil assets. In many cases, it is beneficial to coordinate risk mitigation activities under a single redevelopment or rehabilitation project rather than undertaking numerous separate projects. The resulting benefits of coordination include improved efficiency in project delivery, reduced project costs, shorter outages and a reduction in the complexity of project management oversight.

Table 6-16 below provides a summary of the fiscal 2020 to fiscal 2021 capital additions and capital expenditures. More information on the projects listed can be found in Appendix I, page1, lines 2 and 3 and Appendix J, page 3.

Table 6-16 Hydroelectric Generation Redevelopment/Rehabilitation Projects Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021[306] ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Redevelopment / Rehabilitation				
G000597	John Hart Generating Station Replacement	23.2	-	23.1	-
G003085	Project A	14.5	-	0.5	-
	Projects & Programs Less than $5M	5.1	-	5.1	
	Total Redevelopment / Rehabilitation	**42.8**	**-**	**28.6**	**-**

Projects and Programs Less than $5 million line are related to project closeout costs for projects placed in-service in the prior test period.

6.4.13.4 Dam Safety Projects

Dam Safety projects are focused on mitigating safety risks associated with dams and other water conveyance or retention infrastructure within a hydroelectric setting, as generally described in section 6.4.1.3.

Aging and normal wear and tear of our dams present constant challenges. BC Hydro's aim is to manage the whole fleet of dams so there is no significant deterioration in the risk position and the overall level of risk is kept well within limits considered to be tolerable. Whenever it is possible to make improvements or necessary to take remedial measures, BC Hydro first refers to international and Canadian best practices, seeking to achieve as large an increment to safety as possible, and at the very minimum, not to accept any reduction in the level of safety

306 Project A refers to a project which is confidential due to the sensitive commercial nature of the project information.

while work is in progress. BC Hydro seeks to balance the cost of each possible improvement against the added safety benefits it would achieve.

Table 6-17 below provides a more detailed breakdown of the fiscal 2020 to fiscal 2021 Dam Safety capital additions and capital expenditures that were summarized in Table 6-7 and Table 6-8. More information on the projects listed can be found in Appendix I, page 1, lines 4 to 22 and Appendix J, pages 5 to 25.

Table 6-17 Dam Safety Projects - Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Dam Safety				
G000656	W.A.C. Bennett Dam Spillway Gate Upgrade	25.9	8.2	9.0	8.2
G000011	Alouette Improve Headworks & Surge Tower Seismic Stability	-	-	1.5	5.4
G003852	Bridge River 1 - Mitigate Surge Spill Hazard	4.9	0.1	4.6	0.1
G003467	Bridge River 1 Improve Slope Drainage	8.2	-	7.1	-
G000657	Comox - Puntledge Flow Control Improvements	-	-	6.5	17.2
G000755	Duncan Dam Replace Spillway Gates	-	-	0.2	2.3
G000585	John Hart Dam Seismic Upgrade	-	-	9.2	19.5
G000668	Ladore Spillway Seismic Upgrade	-	-	1.9	2.9
G003127	Peace Canyon Install Piezometers and Drains in Concrete Dam	-	-	0.3	1.0
G000246	Revelstoke Improve Left Bank Slope Stability	-	11.5	3.9	7.3
G003129	Revelstoke Replace Downie Slide Instrumentation	-	-	1.2	3.3
G000525	Strathcona Upgrade Discharge	-	-	7.1	19.3
G003554	W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates	-	-	0.5	10.7
G003555	W.A.C. Bennett Dam Seal Low Level Outlets	-	-	0.9	3.8
G000001	Alouette - Environmental Flow Discharge Upgrade and LLO Sealing	-	-	0.2	2.2
G000556	Hugh Keenleyside - Spillway and Low Level Outlets Concrete Upgrade	-	-	-	1.1
G003365	Mica - Discharge Facilities Seismic and Reliability Upgrades	-	-	-	2.2
G000467	Terzaghi - Spillway Chute Access Improvement	-	12.0	1.2	10.8
G003653	Various Sites - Reservoir Booms Replacement - F2020	-	5.9	1.0	5.6
	Projects & Programs Less than $5M	10.3	6.7	12.3	7.2
	Total Dam Safety	**49.3**	**44.4**	**68.8**	**130.0**

Capital investments in the Projects and Programs Less than $5 million line include projects to install, replace or rehabilitate instrumentation in dams and to implement miscellaneous upgrades of water conveyances and gates.

Dam Safety capital expenditures decreased over the fiscal 2017 to fiscal 2019 period for two main reasons:

- Completion of a number of projects within the period, including GMS – W.A.C. Bennett Dam Spillway Chute Rehabilitation, GMS – W.A.C. Bennett Dam Riprap Upgrade and Hugh Keenleyside (**HLK**) - Spillway Gate Reliability Upgrade; and
- The initiation and early design progression of a number of large projects, for which the large capital expenditures associated with procurement and construction have yet to arise.

This portfolio of capital expenditures consists mainly of large multiple year projects and is therefore subject to fluctuations in year over year spend. The planned Dam Safety capital expenditures are expected to increase through the test period due to the advancement and increased levels of activity for these large projects.

Relatively high Dam Safety capital additions in fiscal 2018 and fiscal 2019 are due to the completion and the placing in-service of a number of projects within the period, as described above. Capital additions in fiscal 2020 and fiscal 2021 are expected to be lower because the majority of Dam Safety projects will be in various stages of design or construction during this period, with capital additions not expected until after fiscal 2021.

6.4.13.5 GMS-W.A.C. Bennett Dam Riprap Upgrade Stockpile Costs

On November 13, 2015, BC Hydro filed an application with the BCUC to upgrade the riprap on the W.A.C. Bennett Dam. The BCUC accepted the project's expenditure schedule with the exception of the costs associated with Maintenance and Emergency Stockpile (**MES**) of riprap. The BCUC directed that, in future revenue requirement applications, BC Hydro either confirm that no expenditures relating to emergency stockpile riprap are included in the revenue requirements or explain otherwise.[307] In August 2017, BC Hydro notified the BCUC that it was proceeding

[307] BCUC Order No. G-78-16, Appendix A, page 44.

with expenditures for the MES and would seek recovery of the costs in accordance with BCUC Order No. G-78-16.

BC Hydro believes that the MES costs are in the public interest and should be recovered in rates.

The actual cost for the riprap Stockpile was $0.7 million, which is $3.6 million less than the $4.3 million estimated in the November 13, 2015 application and the August 2016 update to the BCUC. BC Hydro was able to substantially reduce the cost by adjusting the size of the rock from Class 1 to Class 3 riprap and by reducing the total volume of rock required.

Based on lessons learned from the placement of the larger Class 1 riprap rock during the first season of riprap placement, BC Hydro determined it was preferable to use smaller rocks for both maintenance and emergency situations. Smaller rocks require equipment that is more readily available within a short timeframe and were produced from the waste material leftover from the quarrying Class 1 riprap rock. This meant that no further quarry expansion or blasting was required. As a result, the only incremental cost for the riprap stockpile was related to sorting the Class 3 rock and transporting it from the quarry to the stockpile area. This Class 3 rock would have otherwise been considered waste material.

After considering further engineering review and the decision to use smaller rock, BC Hydro determined that a reduced amount of rock would be sufficient for maintenance and emergency purposes. The final MES volume was 7,695 tonnes (~4,053 cubic meters) of smaller Class 3 riprap rock, which is approximately 50 per cent less than the 15,000 tonnes (~8,000 cubic meters of Class 1 riprap) included in the November 13, 2015 application.

BC Hydro believes that creating the riprap stockpile for maintenance and emergency purposes is prudent and provides good value to ratepayers. Specifically, this stockpile provides:

- **An inexpensive way to extend the life of the project** – The expected 50-year life of the riprap could be extended by 50 to 100 per cent with proper maintenance and repair, utilizing limestone rock from the MES. Any type of rock has natural variability, such as freeze/thaw splitting or breakage characteristics and a significant storm event could happen at any time, causing damage that could impact the underlying dam structure if it is not quickly identified and addressed. If BC Hydro was required to implement a reactive maintenance program, it would cost considerably more than $0.7 million;
- **Higher quality rock** – A pre-existing sandstone stockpile at the W.A.C. Bennett Dam is not acceptable for maintenance or emergency purposes. Sandstone riprap does not have the same life expectancy as limestone riprap[308] and repairs using sandstone riprap would require subsequent replacement in the future, ultimately leading to higher costs. A temporary fix, in an emergency situation, followed by a subsequent replacement project would also likely require reservoir re-operation which would result in lost revenue or higher energy costs from other sources;
- ***A Readily Available Source of Limestone Riprap*** – As the Riprap Upgrade project has now been completed, the quarry would need to be re-opened to acquire additional limestone rock, which would require additional permitting, consultation with First Nations, and securing a contractor willing to take on the relatively small production. This would likely take one to two years, or more, to complete. While there is a limestone quarry located 170 kilometres from the W.A.C. Bennett Dam, quarrying from this site would also require lengthy consultation, permitting and procurement processes; and
- ***Best practice for maintenance and emergency purposes*** – In 2018, BC Hydro polled the members of the Center for Energy Advancement through

[308] This is based on a 2013 internal engineering review of the suitability of Sand Flat Limestone and Portage Mountain East Sandstone riprap.

Technical Innovation (**CEATI**) Dam Safety Interest Group to confirm whether it was best practice to stockpile rock for maintenance and emergency purposes. BC Hydro received 20 responses, and all respondents, except for those that have ready access to emergency quarry supplies and transportation, indicated that they also maintain maintenance and emergency stockpiles and that this is considered best practice. BC Hydro does not have ready access to maintenance and emergency quarry supplies for the W.A.C. Bennett Dam.

Therefore, in this application, BC Hydro requests the BCUC approval of expenditures related to the MES of riprap for the W.A.C. Bennett Dam.

6.4.13.6 Generation Sustaining – Other Projects

Generation sustaining investments classified as Other Projects are initiated to mitigate or resolve key risks identified with existing assets. These investments can include:

- Projects to replace major generating equipment that is in Poor or Unsatisfactory condition;
- The replacement or upgrade of auxiliary equipment or facility infrastructure such as fire protection systems, Heating, Ventilating and Air Conditioning (**HVAC**) systems, piping systems, roofs, remote town site accommodation and cranes; and
- Projects to address safety and environmental risks or address regulatory compliance.

Sustaining-Other capital expenditures over the fiscal 2017 to fiscal 2021 period are generally increasing due to a large number of investments progressing through early project life-cycle phases. Capital additions fluctuate over the fiscal 2017 to fiscal 2021 period as projects from the previous test period are put in-service.

Table 6-18 below provides a summary of the fiscal 2020 to fiscal 2021 capital additions and capital expenditures. More information on the projects listed can be found in Appendix I, page 1 and 2, lines 23 to 84 and Appendix J, pages 27 to 66.

Table 6-18 Generation Sustaining-Other Projects - Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Sustaining - Other				
G000492	Bridge River 2 Upgrade Units 5 and 6	2.8	8.7	2.8	8.7
G000571	Cheakamus Replace Units 1 and 2 Turbine Inlet Valves	2.9	7.3	2.7	0.8
G000614	Cheakamus Units 1 and 2 Generator Replacement	32.4	5.2	11.0	5.2
G000127	G.M. Shrum G1 to 10 Control System Upgrade	6.0	21.0	15.1	9.5
G000121	G.M. Shrum Replace Unit 1-5 Exciter Transformers	4.9	0.8	2.7	0.8
G000374	Kootenay Canal Upgrade Unit Protection and Install Sequence of Events Recorder	3.8	-	0.3	-
G000789	Mica Replace Fire Alarm System	7.5	-	2.0	-
G003207	Mica Replace Units 1 to 4 Generator Transformers	12.1	12.3	15.3	12.9
G003362	Mica Townsite Augment Accommodations Capacity	20.5	1.5	2.8	1.5
G003542	Mica Upgrade Powerhouse Cranes	26.8	0.4	3.4	0.4
G000057	Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)	-	31.5	5.8	23.3
G000135	G.M. Shrum Replace / Refurbish 500KV Disconnect Switches	-	-	2.7	1.6
G000114	G.M. Shrum Upgrade HVAC System	-	-	1.4	15.9
G000747	Hugh Keenleyside Replace Service Water Piping	-	8.8	6.9	1.2
G000962	Kootenay Canal Upgrade Powerhouse Crane	8.8	-	7.1	-
G000165	Lake Buntzen 1 - Power House Crane Upgrade	6.9	-	5.2	-
G000640	Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment	-	-	1.7	7.7
G000172	Mica Modernize Controls	4.4	4.5	8.8	8.6
G003456	Mica Upgrade 600V Circuit Breakers	4.4	12.0	5.4	9.2
G000801	Mica Upgrade HVAC System	-	12.6	2.4	9.4
G000219	Peace Canyon Upgrade HVAC System	-	-	1.0	2.2
G000241	Puntledge Recoat Interior and Exterior of Steel Penstock	-	1.3	7.9	6.1
G001008	Revelstoke - 600V Circuit Breaker Upgrades	-	-	0.6	5.5
G000792	Seven Mile Replace Unit 1-4 Exciter Transformers	-	8.6	4.0	3.7
G003515	Various - Water License Renewal	-	5.3	0.8	0.6
G000342	Wahleach Recoat Penstock (Interior and Exterior)	-	26.0	4.6	19.7
G000334	Wahleach Refurbish Generator	-	-	6.3	5.5
G000042	Ash River Extend Life of Steel Penstock	-	-	0.3	0.7
G000485	Bridge River 1 - Strip and Recoat Penstocks 1-4 Interior	-	-	3.0	4.7
G000776	Bridge River 1 Replace Units 1-4 Generators / Governors	-	-	3.7	10.5
G000489	Bridge River 2 - Strip and Recoat Penstock 2 Interior	-	16.6	3.1	13.0
G000493	Bridge River 2 Upgrade Units 7 and 8	-	54.7	11.5	41.1
G003035	Hugh Keenleyside Recoat Navlock Gates	-	-	0.3	4.4
G000158	Jordan - Upgrade Governor & PRV Controls	-	-	2.4	5.1
G000952	Kootenay Canal Modernize Controls	-	-	0.2	7.6
G000741	Ladore - Redevelop Unit 1	-	-	0.6	3.3
G000517	Ladore Upgrade Protection and Control Systems	-	-	0.1	0.3
G000169	Lake Buntzen 1 Penstock Exterior Recoat	-	-	0.5	0.9
G000174	Mica - Recoat Intake Maintenance Gates & Draft Tube Maintenance Gates	-	4.3	1.7	2.1
G000220	Peace Canyon - 600V Circuit Breaker Upgrades	-	-	1.9	0.8
G003373	Revelstoke Replace Fire Alarm System	-	-	2.6	5.7
G003026	Seton - Upgrade Unit	-	-	0.6	4.5
G000834	Seven Mile - Replace T1 Transformer	-	-	0.6	1.6
G000796	Seven Mile Overhaul Units 1 to 3 Turbines	-	-	2.1	2.1
G000822	Seven Mile Upgrade Powerhouse Crane Controls	-	-	0.4	3.2
G003755	Stave Falls - Improve Unit 1&2 Turbine Pitch Assemblies	-	-	0.2	1.6
G003422	Various - Remediate PCB Contaminated Equipment	-	-	1.3	2.6
G003449	Various Facilities Replace Water Level Gauges	-	-	0.3	1.1

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
G001047	Waneta U3 Life Extension	-	-	3.4	3.1
G000131	G.M. Shrum - Intake Operating Gate and Intake Maintenance Gate Refurbishment	-	-	-	0.3
G003336	G.M. Shrum - Intake Operating Gate Hydraulic Upgrade	-	-	-	0.4
G003826	G.M. Shrum - Pauwels Transformer Life Extension	-	-	-	0.1
G000133	G.M. Shrum - Transformers Phase 4 Replacement	-	-	0.7	3.0
G000130	G.M. Shrum - U1 - U10 Water Passage Refurbishment	-	-	-	0.7
G000120	G.M. Shrum - U9 - U10 Circuit Breaker Replacement	-	-	0.2	0.3
G000168	Lake Buntzen 1 - Generator Replacement	-	-	-	1.8
G000195	Mica - Intake Gantry Crane Refurbishment	-	-	0.6	4.1
G000231	Peace Canyon - High and Low Pressure Piping Replacement	-	-	-	0.4
G003835	Peace Canyon - U1 - U4 Exciter Replacement	-	-	-	0.4
G000252	Revelstoke - U1 - U4 Stator Replacement	-	-	-	1.2
G000436	Seven Mile - U1 - U4 Controls Upgrade	-	-	0.3	1.1
G001918	Strathcona - G1 Generator Rewind	-	-	-	2.2
	Projects & Programs Less than $5M	55.3	71.5	67.7	65.0
	Total Sustaining - Other	**199.4**	**315.3**	**241.0**	**361.1**

Capital investments in the Projects and Programs Less than $5 million line include a large number of smaller less complex investments. In general, these are targeted sustaining investments for specific components or systems that support the generation of electricity. These investments can be broadly classified as follows:

- Auxiliary equipment and plant support systems such as crane and hoist upgrades/replacements, small recoating projects, control systems and instrumentation, pumps, diesels, field breakers, pressure vessels, transformer bushings, unwatering and drainage systems, air and water supply piping, station battery systems, communication upgrades;
- Building infrastructure and associated systems such as roof and HVAC replacements, elevator refurbishment, sanitary and fire protection system upgrades;
- Safety and security such as fall arrest, safe work platforms, arc flash hazards, fencing, signage, public access control and security system upgrades; and
- Environmental projects such as installing fish weirs at Duncan Dam.

6.4.13.7 Non-Integrated Areas – Investments to Sustain Existing Assets

All expenditures in fiscal 2020 to fiscal 2021 in Non-Integrated Areas are to sustain existing assets. Non-Integrated Areas are separate self-contained areas. Each area has its own source of generation (usually diesel generators), associated switchyard, support buildings and distribution network. As the assets age and deteriorate they need to be replaced so that a safe reliable level of service can be maintained to Non-Integrated Area customers. The sustaining investment projects and programs can be classified into the following categories:

- Genset replacements and overhauls;
- Fuel infrastructure upgrades;
- Communication & Control upgrades;
- Station building upgrades; and
- Line building replacements.

Table 6-19 Non-Integrated Areas Generation Projects - Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Non-Integrated Areas				
	Projects & Programs Less than $5M	7.9	5.8	8.7	5.0
	TOTAL Non-Integrated Areas	**7.9**	**5.8**	**8.7**	**5.0**

The forecast capital expenditures and additions are higher than fiscal 2017 to fiscal 2019 as a genset fleet modernization program is completed.

6.4.13.8 Thermal Generation Sustainment Investment

Thermal Generation investments mitigate or resolve key risks identified with existing Thermal Generation assets.

Table 6-20 below provides a summary of the fiscal 2020 to fiscal 2021 capital additions and capital expenditures.

Table 6-20 Thermal Generation Projects - Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Projects & Programs Less than $5M	3.8	6.1	6.6	4.5
	TOTAL Thermal	**3.8**	**6.1**	**6.6**	**4.5**

All Thermal Generation capital investments fall within the Projects and Programs Less than $5 million line. Projects over the test period include investments at Burrard, Fort Nelson and Prince Rupert for facility upgrades, roof replacement, and fire protection system upgrades.

6.4.14 Transmission and Distribution Assets Capital Expenditures and Additions

The actual and plan capital expenditures and additions for fiscal 2017 to fiscal 2021 for Transmission and Distribution, classified by Growth and Sustain categories are provided in Table 6-21 and Table 6-22 below.[309]

[309] Fiscal 2017 and fiscal 2018 variances greater than $10 million are described in Appendix G, section 5.

Table 6-21 Transmission and Distribution Actual and Plan Capital Expenditures Fiscal 2017 to Fiscal 2021

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Transmission								
Growth	262.0	247.3	222.0	280.5	192.7	240.7	197.2	208.9
Sustaining	255.5	268.1	326.3	218.3	373.9	218.2	244.5	315.6
Less: Portfolio Risk Adjustment						(26.0)	(34.0)	(39.0)
Distribution								
Growth	224.7	226.0	233.4	287.6	209.5	305.7	300.0	284.6
Sustaining	185.0	224.5	160.1	235.2	187.6	190.9	187.5	176.8
Total	927.3	965.9	941.8	1,021.6	963.7	929.5	895.2	946.9
Less: Contribution in Aid	(86.4)	(138.7)	(100.2)	(156.3)	(106.4)	(146.9)	(157.8)	(148.4)
TOTAL	840.9	827.2	841.6	865.3	857.3	782.6	737.4	798.5

Table 6-22 Transmission and Distribution Actual and Plan Capital Additions Fiscal 2017 to Fiscal 2021

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Transmission								
Growth	237.1	255.8	222.8	176.9	213.8	364.9	97.9	85.3
Sustaining	255.2	227.1	216.9	230.8	245.0	225.5	217.9	234.3
Less: Portfolio Risk Adjustment						(57.0)	(22.0)	(90.0)
Distribution								
Growth	189.8	232.7	241.6	232.2	229.0	305.2	306.9	344.2
Sustaining	182.3	188.3	157.7	213.3	184.0	222.3	195.3	196.5
Total	864.4	903.9	839.0	853.2	871.8	1,060.9	796.0	770.3
Less: Contribution in Aid	(89.8)	(101.7)	(88.0)	(129.5)	(84.6)	(148.5)	(146.2)	(165.8)
TOTAL	774.6	802.2	751.0	723.7	787.2	912.4	649.8	604.5

6.4.14.1 Transmission Planned Capital Expenditures and Additions

Transmission capital expenditures and additions include Substation Distribution Asset expenditures and additions. The Substation Distribution Asset costs are tracked separately, enabling the determination of transmission function costs for rate design and other purposes. Table 6-23 and Table 6-24 below provide functional details regarding the actual and plan capital expenditures and additions.[310]

[310] Fiscal 2017 and fiscal 2018 variances greater than $10 million are described in Appendix G, section 5.

1 Table 6-23 Transmission Actual and Plan Capital
2 Expenditures Fiscal 2017 to Fiscal 2021

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Transmission Growth								
Regional System Reinforcement	92.2	120.8	68.4	89.2	66.4	180.4	107.9	91.1
Bulk System Reinforcement	30.1	20.9	7.2	115.2	24.4	5.9	12.0	43.3
Station Expansion & Modification	88.8	73.1	74.0	55.8	59.2	24.2	11.9	22.5
Feeder Positions / Section Additions	1.1	1.0	1.2	0.7	-	2.0	1.6	2.1
Generator Interconnections	30.3	16.9	41.4	7.2	15.1	10.1	5.1	3.6
Transmission Load Interconnections	19.5	14.5	29.7	12.4	27.7	18.1	58.7	46.3
Growth Total	262.1	247.3	222.0	280.5	192.7	240.7	197.2	208.9
Transmission Sustain - Stations								
Circuit Breakers	28.2	34.7	18.6	34.8	12.8	26.9	16.3	28.2
Other Power Equipment	48.5	77.5	80.8	54.4	143.3	37.1	63.5	104.6
Protection and Control	11.6	9.4	22.3	7.4	21.7	17.6	18.4	16.3
Stations Auxiliary Equipment	30.6	26.9	20.6	18.6	22.8	28.6	25.6	29.8
Stations Risk Mitigation	6.5	4.9	8.3	2.0	8.7	5.5	12.9	10.0
Telecommunications	7.7	5.6	14.1	6.7	12.4	17.0	25.4	25.1
Sustain Stations Total	133.2	159.0	164.7	123.9	221.6	132.7	162.1	214.0
Transmission Sustain - Lines								
Cable Sustainment	12.0	8.2	30.0	28.0	21.5	2.2	5.0	8.9
O/H Lines Life Extension	72.4	63.3	94.6	27.4	89.9	47.4	45.5	70.1
O/H Lines Performance Improvement	4.1	6.8	3.8	3.7	4.3	1.4	1.4	1.4
O/H Lines Risk Mitigation	17.5	10.1	15.4	20.9	20.9	11.7	10.7	3.6
ROW Sustainment	10.2	11.5	10.4	9.8	10.5	11.2	9.7	9.8
Third Party Requested Transmission Line Relocations	6.2	9.1	7.5	4.6	5.2	11.6	10.0	7.8
Sustain Lines Total	122.4	109.0	161.6	94.3	152.3	85.5	82.3	101.6
Less: Portfolio Risk Adjustment						(26.0)	(34.0)	(39.0)
Total Transmission	517.6	515.4	548.3	498.7	566.6	432.9	407.7	485.5
Less: Contribution in Aid	(9.8)	(15.8)	(21.8)	(15.6)	(26.2)	(17.1)	(23.7)	(14.8)
Total Net	507.8	499.6	526.5	483.2	540.5	415.8	384.0	470.7

Table 6-24 Transmission Actual and Plan Capital Additions Fiscal 2017 to Fiscal 2021

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Transmission Growth								
Regional System Reinforcement	117.9	146.3	9.7	13.2	129.7	127.9	83.8	58.2
Bulk System Reinforcement	18.2	11.4	26.4	7.0	0.8	131.6	0.1	-
Station Expansion & Modification	37.7	35.5	149.6	125.8	74.2	87.4	2.5	0.5
Feeder Positions / Section Additions	2.0	1.9	0.0	0.1	1.2	0.9	2.5	0.2
Generator Interconnections	55.7	56.3	13.8	12.7		12.3	1.2	10.3
Transmission Load Interconnections	5.7	4.5	23.4	18.1	7.9	4.8	7.8	16.1
Growth Total	237.1	255.9	222.8	176.9	213.8	364.9	97.9	85.3
Transmission Sustain - Stations								
Circuit Breakers	56.4	95.9	17.6	19.9	13.5	42.2	28.0	11.3
Other Power Equipment	41.4	36.6	36.8	80.2	58.6	38.2	21.9	50.4
Protection and Control	13.0	16.0	20.1	7.3	21.8	2.2	11.2	13.1
Stations Auxiliary Equipment	29.0	13.5	23.5	23.9	22.6	20.7	40.1	26.8
Stations Risk Mitigation	6.7	7.8	7.9	6.2	8.6	4.2	4.0	20.0
Telecommunications	7.8	4.4	11.9	5.6	12.5	3.5	13.6	37.4
Sustain Stations Total	154.4	174.2	118.0	143.2	137.6	111.0	118.8	159.0
Transmission Sustain - Lines								
Cable Sustainment	4.9	1.7	4.2	2.0	8.6	1.9	4.1	2.3
O/H Lines Life Extension	55.4	6.4	60.7	50.4	52.4	72.0	49.1	41.8
O/H Lines Performance Improvement	4.4	1.4	3.9	6.2	4.2	4.9	1.4	1.4
O/H Lines Risk Mitigation	19.8	24.7	15.8	12.5	19.8	12.0	16.2	10.2
ROW Sustainment	10.7	9.2	10.4	12.3	10.5	15.6	19.3	9.8
Third Party Requested Transmission Line Relocations	5.5	9.6	4.0	4.2	11.9	8.1	9.0	9.8
Sustain Lines Total	100.8	52.9	98.9	87.7	107.4	114.5	99.1	75.3
Less: Portfolio Risk Adjustment						(57.0)	(22.0)	(90.0)
Total Transmission	492.3	482.9	439.7	407.7	458.8	533.4	293.8	229.6
Less: Contribution in Aid	(13.8)	(22.0)	(9.7)	(16.6)	(4.4)	(19.3)	(15.2)	(29.2)
Total Net	478.5	460.9	430.0	391.1	454.4	514.1	278.6	200.4

6.4.14.2 Transmission Assets Growth Expenditures and Additions

Regional System Reinforcement

The regional transmission systems generally comprise a large portion of the 230 kV system and all of the 138 kV and 60 kV systems. Regional transmission systems include transmission facilities that service localized geographic areas. Transmission Growth projects at this level often involve the installation of additional regional capacity in order to support area load growth and maintain area supply reliability and can include upgrades of, and additions to, lines or substation equipment.

Table 6-25 below provides a summary of the plan capital additions and expenditures for fiscal 2020 to fiscal 2021. More information on the projects listed can be found in Appendix I, page 4, lines 1 to 8 and Appendix J, pages 67 to 80.

Table 6-25 Transmission Regional System Reinforcement Projects Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Regional System Reinforcement				
92525	Fort St. John and Taylor Electric Supply	-	53.4	21.1	3.2
900219	DVES: West End Strategic Property Purchase	80.7	0.0	3.0	0.0
92216	Peace Region Electric Supply (PRES)	-	-	66.1	56.2
93845	Metro North Transmission (MNT)	-	-	-	1.0
92423	Bridge River Transmission Project	-	-	1.7	7.5
94034	West Kelowna Transmission and Westbank Upgrade Projects	-	-	6.8	9.4
900266	East Vancouver - Substation Construction	-	-	3.8	9.1
900598	West End - Substation Construction and System Reinforcement	-	-	-	2.7
	Projects & Programs Less than $5M	3.1	4.8	5.4	2.0
	TOTAL Regional System Reinforcement	**83.8**	**58.2**	**107.9**	**91.1**

Capital investments in the Projects and Programs Less than $5 million line include project closeout costs for projects placed in-service in the fiscal 2017 to fiscal 2019 period, such as the Horne Payne Substation Upgrade project.

Regional System Reinforcement capital expenditures decrease over the fiscal 2020 and fiscal 2021 period from the fiscal 2017 to fiscal 2019 period due to the completion of some projects, such as the Horne Payne Substation Upgrade, the Kamloops Substation Project which were completed at the end of the previous test period, and the progression of on-going projects including the Peace Region Electric Supply Project and the Fort St. John and Taylor Electric Supply Project.

Capital additions vary over the fiscal 2017 to fiscal 2021 period as additions associated with the larger reinforcement projects tend to be lumpy. Capital additions are decreasing over the fiscal 2020 to fiscal 2021 period as newer projects progress through the earlier phases of the project lifecycle into implementation.

Bulk System Reinforcement

The bulk system comprises high voltage transmission lines and related equipment that interconnect the large remote generating stations in the Peace River and Columbia River areas with the major load centres in the Lower Mainland and on Vancouver Island. The bulk system includes the 500 kV transmission system, the transmission connections to Vancouver Island, and interconnections with other utilities through external and internal interties to FortisBC, Rio Tinto Alcan, Alberta and the U.S.

Table 6-26 below provides a summary of the fiscal 2020 to fiscal 2021 capital additions and capital expenditures. More information on the projects listed can be found in Appendix I, page 4, lines 9 to 11 and Appendix J, pages 82 to 86.

Table 6-26 Transmission Bulk System Reinforcement Projects Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Bulk System Reinforcements				
90957	Peace to Kelly Lake Capacitors	-	-	11.5	41.1
900992	Lower Mainland - Capacitive and Reactive Power Reinforcement	-	-	-	0.4
901251	Interior to Lower Mainland - Remedial Action Schemes Installation	-	-	-	0.8
	Projects & Programs Less than $5M	0.1	-	0.5	1.0
	TOTAL Bulk System Reinforcements	**0.1**	**-**	**12.0**	**43.3**

The trend in Bulk System Reinforcement capital expenditures and additions over the fiscal 2017 to fiscal 2021 period is relatively stable, with the exception of fiscal 2018 expenditures and fiscal 2019 additions, due to increased costs of the Interior to Lower Mainland Transmission Line project. Capital expenditures increase over fiscal 2020 to fiscal 2021 due to the Peace to Kelly Lake Capacitors Project.

Station Expansion and Modifications

Station expansion and modification projects replace, upgrade, or add capacity to existing substations to alleviate operational constraints or limitations resulting from local load growth. These projects impact transmission and distribution assets within the substation, and may involve installing additional transformer capacity, adding switchgear, converting to higher voltages, and reconfiguring existing facilities to accommodate increased capacity requirements.

Table 6-27 below provides a summary of the capital additions and capital expenditures for the test period. More information on the projects listed can be found in Appendix I, page 4, lines 12 to 16 and Appendix J, pages 87 to 95.

Table 6-27 Station Expansion and Modification Projects Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Station Expansion & Modification				
93788	Capilano Substation 25Kv Conversion	-	-	1.9	6.0
92907	Mount Lehman Substation Upgrade	-	-	7.3	9.6
92910	Clayburn Substation Upgrade	-	-	1.5	5.2
93632	Project B (Substation)	-	-	0.2	0.0
900816	Pemberton - Substation Upgrade	-	-	-	0.5
	Projects & Programs Less than $5M	2.5	0.5	1.0	1.1
	TOTAL Station Expansion & Modification	**2.5**	**0.5**	**11.9**	**22.5**

Capital investments included in the Projects and Programs Less than $5 million line include closeout costs associated with projects put in-service in the prior test period such as the Arnott Capacity Upgrade, Campbell River Substation Capacity Upgrade, and the South Surrey Area Reinforcement project.

As early phase projects such as Mount Lehman Substation Upgrade, Clayburn Substation Upgrade, and the Capilano Substation 25 kV Conversion progress, the expenditures will start to increase in fiscal 2021. The relatively higher capital additions in fiscal 2018 are due to in-service additions from projects including the Fernie Substation Upgrade and Big Bend Substation.

Feeder Position/Section Additions

Feeder positions and feeder sections are located within substations and supply the interface between the substation and the distribution system for BC Hydro's distribution connected customers. These projects provide additional capacity for distribution customer load growth or for increased operational flexibility.

Table 6-28 Feeder Position/Section Additions Projects Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Feeder Positions / Section Additions				
	Projects & Programs Less than $5M	2.5	0.2	1.6	2.1
	TOTAL Feeder Positions / Section Additions	**2.5**	**0.2**	**1.6**	**2.1**

All Feeder Positions/Section Additions investments within the test period are included in the Projects and Programs Less than $5 million line. Station Expansion and Modifications projects, such as the Mount Lehman Substation Upgrade and the Capilano Substation 25 kV Conversion will also address additional feeder position requirements within the test period.

Generator Interconnections

Generator interconnection projects involve the design and construction of facilities that are required to connect and integrate generation projects to the existing transmission system. The Open Access Transmission Tariff (**OATT**) governs the generator interconnection process, and defines the cost responsibilities between BC Hydro and the generator.

For a new generator the interconnection facilities can range from a simple transmission tap onto an existing transmission circuit, a transmission line termination at an existing switching station / substation, or a new switching station / substation. Associated protection, control, and communication facilities are also usually built. To integrate a generator into a regional network BC Hydro may also need to reinforce the existing transmission lines to enable higher energy flows.

To determine the scope of upgrades required for a project, BC Hydro will perform a series of interconnection studies that identify impacts to the transmission system and the required network upgrades. Under the OATT, the customer is responsible to bring their system to the BC Hydro transmission system, which includes designing, procuring and funding their interconnection facilities. BC Hydro is responsible to design, procure, construct and fund the network upgrades within the BC Hydro transmission system. The customer is required to provide security for the estimated cost of the network upgrades, which is returned over time to the customer per the tariff.

Until recently, the majority of new IPP interconnections resulted from BC Hydro's Standing Offer Program. The program limited the funding BC Hydro provided for network upgrades to a pre-determined threshold amount. The forecasts for interconnection costs for projects already in the program include only the estimated network upgrade costs up to the threshold. They do not include the costs of the network upgrade above the threshold.

Table 6-29 below provides a summary of the plan capital additions and capital expenditures for fiscal 2020 to fiscal 2021. More information on the projects listed can be found in Appendix I, page 4, line 17.

Table 6-29 Generator Interconnection Projects Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Generation Interconnections				
900626	Bremner-Trio Hydro Project	-	7.3	4.1	0.7
	Projects & Programs Less than $5M	1.2	3.0	0.9	2.9
	TOTAL Generation Interconnections	**1.2**	**10.3**	**5.1**	**3.6**

Only those projects with a high probability of proceeding are included as individual projects in the capital forecast.

Transmission Load Interconnections

Transmission Load Interconnection projects involve the design and construction of facilities to connect and supply new transmission loads or to supply an increase in load at an existing transmission customer's facility. Tariff Supplement No. 6 governs the interconnection and supply of these new transmission loads, including assigning responsibilities to BC Hydro customers as to who is responsible to design, build, operate, own and pay for the various facilities required to interconnect and supply a new load.

For a new transmission load customer the interconnection facilities can range from a simple transmission tap onto an existing transmission circuit, a transmission line termination at an existing switching station/substation, or a new switching station/substation and associated protection, control and communication facilities. In addition to the interconnection facilities, BC Hydro may also need to reinforce the existing transmission system to increase the load supply capabilities.

BC Hydro performs a series of interconnection studies to determine the scope of any interconnection facilities required, the potential impacts on the transmission system, and system reinforcements required to supply the new transmission load. These studies are funded by the customer.

Under Tariff Supplement No. 6, the customer is responsible to design, build, own, operate, and pay for the transmission line from their plant to the BC Hydro transmission system. BC Hydro is responsible to design, build, own, and operate the interconnection facilities; however the customer is required to pay for these facilities and this payment is reported as Contribution in Aid, which is discussed further in section 6.4.14.3, page 6-122. BC Hydro is also required to design, build, own, and operate the transmission system reinforcements and BC Hydro provides a revenue offset towards these system reinforcements as stipulated in Tariff Supplement No. 6. If the estimated future revenues cover the costs of the system reinforcements, the customer is required to provide security for the estimated amount of the system reinforcement up front. If the estimated future revenues do not cover the full cost of the system reinforcement then the customer is required to provide security in the amount of the maximum offset allowable and a cash payment for the difference between the estimated cost of the system reinforcement and the maximum offset amount.

Table 6-30 below provides a summary of the capital additions and capital expenditures for the test period. More information on the projects listed can be found in Appendix I, page 4, lines 18 to 21.

Table 6-30 Transmission Load Interconnections Projects Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Transmission Load Interconnections				
94003	UBC Load Increase Stage 2	-	-	17.8	15.0
900861	Customer A	4.6	0.4	3.2	0.4
93786	Customer B	-	-	28.2	26.6
900836	Customer C	-	15.3	8.9	4.3
	Projects & Programs Less than $5M	3.2	0.4	0.6	0.0
	TOTAL Transmission Load Interconnections	**7.8**	**16.1**	**58.7**	**46.3**

Customer driven interconnection projects include commercially sensitive information, and therefore the names of the specific Transmission Load Interconnection projects are filed in confidence with the BCUC.

6.4.14.3 Transmission Sustaining Expenditures and Additions

Circuit Breakers

Circuit breakers are used to isolate sections of the transmission and distribution system and to interrupt high currents under fault conditions. They are the primary protection device on the transmission and distribution system and must be capable of reliably interrupting both load currents and fault currents. The system currently has over 3,900 circuit breakers made up of a variety of different equipment in terms of voltage classes (from 4 kV to 500 kV).

The planned expenditures for the test period are for the replacement of individual circuit breakers and circuit breakers within a station. The timing of the replacements is based on condition, failure rates and risk to the system. Refurbishment of circuit breakers is considered but usually not possible due to obsolescence.

Table 6-31 below provides a summary of the capital additions and capital expenditures for the test period. More information on the projects listed can be found in Appendix I, page 4, lines 22 and 23 and Appendix J, page 97.

Table 6-31 Circuit Breaker Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Circuit Breakers				
900765	BND 60kV CB and Relay Building Replacement	12.5	0.1	0.9	0.1
900243	SPG Metalclad Switchgear Replacement	-	-	2.4	17.2
	Projects & Programs Less than $5M	15.5	11.2	13.1	10.9
	TOTAL Circuit Breakers	**28.0**	**11.3**	**16.3**	**28.2**

Capital investments included in the Projects and Programs Less than $5 million line include closeout costs for program related work from the prior test period and individual replacements bundled, based on a program delivery approach. The programs are bundled by either voltage class, medium and high voltage, or by type, such as metalclad. In some cases there are specific projects to address circuit breaker risks. The fiscal 2020 to fiscal 2021 planned level of capital expenditures and additions for circuit breakers programs are generally lower than the fiscal 2017 to fiscal 2019 period due to the shift towards replacing lower voltage breakers which generally have a lower unit cost.

Other Power Equipment

Other power equipment expenditures are for the replacement or refurbishment of disconnect switches, surge arrestors, power transformers, instrument transformers, shunt reactors, shunt capacitors, synchronous condensers, high-voltage direct current systems, series capacitor stations, cable terminations, and load tap changers. Table 6-32 below provides a summary of the capital additions and capital expenditures for the test period. More information on the projects listed can be found in Appendix I, page 4 and 5, lines 24 to 40 and Appendix J, pages 98 to 108.

Table 6-32 Other Power Equipment Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Other Power Equipment				
92073	500kV Capacitor Bank P&C Upgrades	-	-	4.4	2.8
900575	Barnard 50/60 Feeder Section Replacement	-	-	7.2	12.1
92166	SC Excitation Systems Upgrade - VIT/KLY	-	-	1.9	1.9
93700	Synch Condensor Functional Imp - F17/F18	-	-	2.7	2.8
92618	VIT & KLY Hydrogen Gas Sys - Safety Upg	-	-	1.7	1.8
900247	BR1 T3 & BRT T4A Replacement	-	18.8	2.4	15.2
900564	Hundred Mile House T1/T2 EOL Replacement	-	-	0.7	2.7
93731	JOR T1 & T2 Replacement	-	-	7.8	14.7
93705	KI1 60Kv Renovatin, 4Kv decommission & control room	-	-	0.8	2.0
92478	Mainwaring Station Upgrade	-	-	5.1	5.7
900152	Natal Sub - NTL 60-138 kV Rebuild	-	-	0.8	1.4
92479	Newell Substation Upgrade	-	-	0.6	2.5
900884	Peace Region to Kelly Lake - Reactor Replacement (Phase 1)	3.6	9.3	4.4	10.5
94081	Ah-sin-heek - Substation Replacement	-	-	0.1	2.1
901034	Norgate - Substation Upgrade	-	-	-	0.5
92759	Patricia - Substation Upgrade	-	-	0.3	5.9
900185	Peace Region to Kelly Lake - Reactor Replacement (Phase 2)	-	0.6	-	0.7
	Projects & Programs Less than $5M	18.3	21.8	22.5	19.1
	TOTAL Other Power Equipment	**21.9**	**50.4**	**63.5**	**104.6**

Capital investments included in the Projects and Programs Less than $5 million line include a number of smaller capital investments such as the Dunsmuir Substation Synchronous VAR Control Upgrade, Fort St. James No. 2 Substation DVAR Upgrade, and Sandspit Substation Replacement, as well as programs to address the replacement of disconnects, instrument transformers, metering kits and substation voltage regulators.

Capital expenditures during the test period increase compared to the previous test period mainly due to the progression of integrated projects initiated to address the replacement of multiple power equipment and circuit breakers within a station. Examples of these integrated projects with expenditures in the test period are the Barnard 50/60 Feeder Section Replacement and the Jordan River T1 and T2

Replacement project. The increase in capital additions in fiscal 2021 is mainly due to the Bridge River-T3 (**BR1 T3**) and Bridge River-T4A (**BRT T4A**) Replacement project.

Protection and Control

Protection and Control expenditures are for the replacement of end of life protective relaying and control systems at substations. Protection and Control assets isolate transmission equipment from electrical faults, ensure stability and reliability of the power system, and provide local and remote control and monitoring of the transmission system. Table 6-33 below provides a summary of the fiscal 2020 to fiscal 2021 capital additions and capital expenditures. More information on the projects listed can be found in Appendix I, page 5 lines 41 to 43 and Appendix J, page 109.

Table 6-33 Protection and Control Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Protection and Control				
900625	NERC CIPv5 Compliance at Medium Impact T&D Stations	-	-	3.4	3.5
900250	Control PLC984 and RTU Replacement (WSN)	-	-	3.1	1.7
93687	Control Systems Upgrade (GMS)	-	-	0.6	3.2
	Projects & Programs Less than $5M	11.2	13.1	11.3	7.7
	TOTAL Protection and Control	**11.2**	**13.1**	**18.4**	**16.3**

The majority of the Protection and Control expenditures in the test period are within the Projects and Programs Less than $5 million line. Expenditures within this category include programs to replace end of life Protection and Control assets in various substations including Supervisory Control and Data Acquisition Remote Terminal Units, digital fault recorders and protection relays.

Capital expenditures and additions are increasing in fiscal 2020 and fiscal 2021 in comparison to the fiscal 2017 to fiscal 2019 test period. The majority of the Protection and Control expenditures over the test period are related to the North American Electric Reliability Council Critical Infrastructure Protection v5 (**NERC CIP v5**) Compliance at Medium Impact Transmission Stations Project and the programs needed to replace an aging fleet of end of life Protection and Control assets.

Stations Auxiliary Equipment

Auxiliary equipment expenditures are for the replacement of station equipment used to support the power system, including station cables, bus work and insulators, steel and wood pole structures, equipment foundations, grounding systems, station power supplies, batteries and chargers, air compressors and dryers, buildings and Heating, Ventilating and Air Conditioning (**HVAC**) equipment, perimeter fences, drainage systems, and gravel. Table 6-34 below provides a summary of the fiscal 2020 to fiscal 2021 capital additions and capital expenditures. More information on the projects listed can be found in Appendix I, page 5, lines 44 to 53.

Table 6-34 Station Auxiliary Equipment Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Stations Auxiliary Equipment				
900787	Wood Pole Substation Rep - MTE	5.3	-	2.9	-
900788	Wood Pole Substation Rep - PSN	5.2	-	2.6	-
93690	Stn Service Transfer & AC panels - WSN	10.4	-	0.2	-
93685	Wood Pole Substation Rep - BTA	-	5.9	3.8	0.1
900726	Joseph Creek (JOE) Substation Upgrade	-	-	0.5	6.2
901244	Cathedral Square - Substation HVAC Upgrade	-	-	-	0.5
900724	Woss - Substation Wood Pole Replacement	-	0.1	-	0.1
901045	Canal Flats - Substation Wood Pole Replacement	-	-	-	0.1
901048	Lumby #2 - Substation Wood Pole Replacement	-	-	0.1	3.2
901049	Skookumchuck - Substation Wood Pole Replacement	-	0.0	-	0.1
	Projects & Programs Less than $5M	19.1	20.8	15.6	19.6
	TOTAL Stations Auxiliary Equipment	**40.1**	**26.8**	**25.6**	**29.8**

Capital investments in the Projects and Programs Less than $5 million line include program expenditures to replace substation wood poles, cables, insulators, diesels, building roofs and battery banks. In addition to the programs there are specific projects to address fire risk reduction at Nicola and Dal Grauer substations.

Station Auxiliary Equipment capital expenditures are consistent across the fiscal 2017 to fiscal 2021 period. Capital additions have increased in the test period compared to the fiscal 2017 and fiscal 2019 period due to an increase in Substation Wood Pole Replacement projects and program expenditures.

Stations Risk Mitigation

The Stations Risk Mitigation expenditures address safety, seismic, environment, severe weather and security risks. Each risk is evaluated based on business impact (e.g., reliability, financial, environmental, safety) and probability of occurrence to determine the appropriate magnitude and duration of investment that is required to mitigate the risk. Table 6-35 below provides a summary of the capital additions and capital expenditures in the test period. More information on the projects listed can be found in Appendix I, page 5, lines 54 and 55.

Table 6-35 Station Risk Mitigation Plan Capital Expenditures and Additions Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Stations Risk Mitigation				
92158	Oil Spill Containment - F17/F18 (ALZ / MDN)	-	7.2	2.5	3.6
900766	Project C	-	4.2	3.1	1.1
	Projects & Programs Less than $5M	4.0	8.6	7.3	5.3
	TOTAL Stations Risk Mitigation	**4.0**	**20.0**	**12.9**	**10.0**

Capital investments in the Projects and Programs Less than $5 million line include programs for fire protection, security and seismic upgrades, at various substations.

Stations Risk Mitigation capital expenditures are increasing in fiscal 2020 and fiscal 2021 in comparison to the previous test period. This is primarily attributable to Station Seismic Upgrades in the Projects and Programs Less than $5 million line, and Project C which is a confidential project due to the sensitive commercial nature of the project information.

Telecommunications

BC Hydro operates a telecommunications network to support operation of the transmission, distribution, and generation systems, as well as voice communications for staff in the field. The telecommunications expenditures are for the replacement of telecommunication infrastructure including microwave radio, power line carrier, fibre optic cable, and VHF/UHF radio. Table 6-36 below provides a summary of the capital additions and capital expenditures in the test period. More information on the projects listed can be found in Appendix I, page 5, lines 56 to 61 and Appendix J, pages 111 and 112.

Table 6-36 Telecommunication Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Telecommunications				
92183	Vancouver Island Radio System	-	21.5	9.6	1.9
92863	Underrated Telecom Classifications - NTL	5.3	0.0	3.1	0.0
92758	CPM MW Repeater Building Rep	-	5.1	2.0	1.4
900709	Various Sites - Telecom Analog Private Line Replacement	0.3	2.3	0.4	2.8
93739	Fraser Valley - Telecom System Reliability Upgrade	-	-	0.5	4.0
92768	Various Sites - Telecom MPLS and DACS Upgrade	-	-	2.1	10.6
	Projects & Programs Less than $5M	8.0	8.5	7.7	4.3
	TOTAL Telecommunications	**13.6**	**37.4**	**25.4**	**25.1**

Capital investments in the Projects and Programs Less than $5 million line include programs to address microwave tower corrosion, and telecom battery, charger and power line carrier LMU replacements

Telecommunication capital expenditures increase across the fiscal 2017 to fiscal 2021 period. This is mainly due to the Vancouver Island Radio System Replacement Project and the program Various Telecom MPLS and DACS Upgrades. Capital additions are increasing in fiscal 2020 and fiscal 2021 in comparison to the fiscal 2017 to fiscal 2019 period due to the CHP MW Repeater Building Replacement and the Vancouver Island Radio System Replacement Project.

Cable Sustainment

Underground and submarine cables are generally used where overhead lines are not feasible or where there is a particular requirement of the site to use cables. There are over 400 km of underground or submarine cables on the transmission system. Most of these circuits are located in Vancouver, Burnaby, Coquitlam and Victoria, and include 69 kV, 138 kV, 230 kV and 500 kV voltage levels. These circuits also include the Strait of Georgia crossings from the mainland to Vancouver Island. Cable sustainment expenditures are for the replacement of cables and ancillary equipment (e.g., pumping equipment and duct banks). Table 6-37 below provides a summary of the capital additions and capital expenditures in the test period. More information on the projects listed can be found in Appendix I, page 5, lines 62 and 63 and Appendix J, pages 113 to 115.

Table 6-37 Cable Sustainment Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Cable Sustainment				
901002	2L146 - Cable Replacement	-	-	1.0	1.6
94057	Gulf Islands - Transmission Reinforcement	-	-	-	5.3
	Projects & Programs Less than $5M	4.1	2.3	4.1	2.0
	TOTAL Cable Sustainment	**4.1**	**2.3**	**5.0**	**8.9**

Capital investments in the Projects and Programs Less than $5 million line account for the majority of the Cable Sustainment expenditures over the test period. Investments included in this line item are programs to address cable instrumentation upgrades, submarine cable inspections, and pumping plant refurbishments.

Capital additions are consistent across the fiscal 2017 to fiscal 2021 period.

Overhead Lines Life Extension

The overhead transmission network consists of conductor systems, metal support structures, wood poles, and associated equipment which includes spacer dampers, aircraft warning markers, and disconnect switches. The overhead network has over 18,400 km of transmission lines. These circuits include approximately 23,000 metal support structures and approximately 116,000 wood poles. Overhead lines life extension expenditures cover the replacement or refurbishment of line components.

Table 6-38 below provides a summary of the capital additions and capital expenditures in the test period. More information on the projects listed can be found in Appendix I, page 5, lines 64 to 67 and Appendix J, page 116.

Table 6-38 O/H Lines Life Extension Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	O/H Lines Life Extension				
91224	Copper Conductor Replace - Phase 2	10.6	-	0.3	-
92840	Circuit Refurbishments - F15 - 2L13/14	-	-	2.7	9.9
94035	5L63 Telkwa Relocation	-	-	3.3	12.2
900889	2L048 - Long Span Crossing Refurbishment	0.1	0.2	0.1	0.2
	Projects & Programs Less than $5M	38.4	41.6	39.2	47.8
	TOTAL O/H Lines Life Extension	**49.1**	**41.8**	**45.5**	**70.1**

The majority of the expenditures within the Overhead Lines Life Extension category fall within the Projects and Programs Less than $5 million line. These investments are mainly structured as programs that target assets across all regions of the province. The programs include the replacement of transmission anchor rods, crossing markers, spacer dampers, line disconnect switches, and insulator replacements. The largest of these programs is devoted to wood structure and framing replacements, which includes pole replacements, bracing and crossarms.

Overhead Lines Life Extension capital expenditures increase from fiscal 2019 to fiscal 2021, while capital additions over the same period decrease. This is due to larger projects such as the 5L63 Telkwa Relocation, and the 2L13/14 Circuit Refurbishment projects progressing through the earlier project lifecycle phases, with in-service dates beyond the test period.

Overhead Lines Performance Improvement

Investments in this category are to address transmission lines subject to localized weather conditions causing performance issues. This work is intended to bring the line back to its designed reliability level. Examples include local sections subject to unequal ice loading, high instances of lightning strikes, or salt fog. Currently, the focus of the expenditures is on reducing lightning caused outages by installing transmission arcing horns. Table 6-39 below provides a summary of the capital additions and capital expenditures in the test period.

Table 6-39 O/H Lines Performance Improvement Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	O/H Lines Performance Improvement				
	Projects & Programs Less than $5M	1.4	1.4	1.4	1.4
	TOTAL O/H Lines Performance Improvement	**1.4**	**1.4**	**1.4**	**1.4**

For the fiscal 2017 to fiscal 2021 period, expenditures within the Overhead Lines Life Performance Improvement are for the installation of arcing horns. Capital expenditures and additions are decreasing over the fiscal 2019 to fiscal 2021 period, due to an intentional delay within the program to allow for an engineering review in advance of the installations.

Overhead Lines Risk Mitigation

The Overhead Lines Risk Mitigation program addresses issues and potential events which could put the system at risk of a prolonged outage or pose safety concerns. Currently, the focus is on reducing the risk to public safety and operating concerns associated with deficient transmission line to ground clearances. Civil protective work to protect transmission structures against flooding and slides are also addressed under this program. Table 6-40 below provides a summary of the capital additions and capital expenditures in the test period. More information on the projects listed can be found in Appendix I, page 5, line 68.

Table 6-40 O/H Lines Risk Mitigation Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	OH Lines Risk Mitigation				
901242	2L101 - Structure 67/1 Permanent Restoration	-	6.5	6.0	-
	Projects & Programs Less than $5M	16.2	3.7	4.7	3.6
	TOTAL OH Lines Risk Mitigation	**16.2**	**10.2**	**10.7**	**3.6**

Capital investments in the Projects and Programs Less than $5 million line include programs to address the replacement of automatic splices, civil protective works, and the refurbishment of overhead guy wires.

Capital additions and expenditures are generally decreasing over the fiscal 2019 to fiscal 2021 period. There are slight increases in the fiscal 2018 capital expenditures and the fiscal 2019 capital additions, which is mainly due to the 1L377 Rating Restoration project, and the 60L210 Rating Restoration project.

Rights-of-Way Sustainment

BC Hydro is responsible for managing the rights-of-way and infrastructure that allow access to the power system, including over 16,000 km of resource roads. This includes roads located along BC Hydro's corridors where BC Hydro is the sole maintainer, and also includes industry-maintained roads leading to the Power System facilities where BC Hydro has shared obligations for road maintenance (such as forest service roads, telecom station roads, and other types of permit roads on Crown land). The Rights-of-Way Sustainment program restores roads in poor condition, and replaces road structures if required (such as bridges, gates, culverts, and retaining walls). The program also acquires and renews legal status of rights-of-way for overhead transmission lines throughout the province.

Table 6-41 below provides a summary of the capital additions and capital expenditures in the test period.

Table 6-41 ROW Sustainment Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	ROW Sustainment				
	Projects & Programs Less than $5M	19.3	9.8	9.7	9.8
	TOTAL ROW Sustainment	**19.3**	**9.8**	**9.7**	**9.8**

All of the Rights-of-Way (**ROW**) Sustainment investments within the test period are included in the Projects and Programs Less than $5 million line. These investments include programs for access repairs and rights acquisition, as described above. Capital expenditures for access related investments are consistent over the fiscal 2017 to fiscal 2021 period. Fluctuations within this category are largely due to rights acquisitions.

Third-Party Requested Transmission Line Relocations

Third-party requested line relocations are expenditures initiated when BC Hydro enters into an agreement with a third-party who wishes to have transmission lines relocated. With the exception of relocations requested by the Ministry of Transportation and Infrastructure for highway rerouting or improvement projects, the third-party will pay for all costs incurred, resulting in an offsetting Contributions in Aid of construction for the capital expenditure. For these projects, BC Hydro recovers costs from the Ministry based on the BC Hydro and Ministry of Transportation and Infrastructure protocol agreement. Under this protocol agreement, BC Hydro recovers approximately 50 per cent of the costs incurred for the relocation of 69kV transmission lines. This cost sharing arrangement recognizes the benefit of rights-of-way provided to BC Hydro by the Ministry of Transportation at no cost. Costs for the relocation of transmission lines greater than 100 kV are recovered from the Ministry at full direct cost. BC Hydro may also relocate transmission lines where legally or contractually obligated.

Table 6-42 below provides a summary of the fiscal 2020 to fiscal 2021 capital additions and capital expenditures.

Table 6-42 Third-Party Requested Transmission Line Relocations Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Third Party Requested Transmission Line Relocations				
	Projects & Programs Less than $5M	9.0	9.8	10.0	7.8
	TOTAL Third Party Requested Transmission Line Relocations	**9.0**	**9.8**	**10.0**	**7.8**

All of the Third-Party Requested Transmission Line Relocations investments in fiscal 2020 to fiscal 2021 are included in the Projects and Programs Less than $5 million line. As the number of requests from third-parties can vary between fiscal years, a provision, based on historical averages, is included within the capital plan to account for future requests.

Contributions in Aid

Contributions in Aid are periodic or lump-sum payments or consideration received from customers or third-parties to provide funding towards the cost of construction or acquisition of an asset where the ownership, operation and maintenance responsibilities remain with BC Hydro. Contributions in Aid is further discussed in the Customer Requested Projects and Third-Party Requested Transmission Line Relocations sections above.

Transmission Contributions in Aid amounts are forecast to increase in fiscal 2020 and then decrease in fiscal 2021 due to the timing of expected payments associated with Transmission Load Interconnection projects listed in Appendix I, page 4, lines 18 to 21.

Transmission Contributions in Aid additions are forecast to increase over the test period due to the planned completion of a number of interconnections and Third-Party Requested Transmission Line Relocation projects in fiscal 2021.

6.4.15 Distribution Capital Expenditures and Additions

The Distribution actual and planned capital expenditures and additions for fiscal 2017 to fiscal 2021 are provided in Table 6-43 and Table 6-44, below.[311]

[311] Fiscal 2017 and fiscal 2018 variances greater than $10 million are described in Appendix G, section 5.

Table 6-43 Distribution Actual and Plan Capital Expenditures Fiscal 2017 to Fiscal 2020

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Distribution Growth								
Customer Driven								
Customer Connections	132.9	163.1	140.2	209.5	141.4	211.0	214.2	216.3
Major Customer Connections	17.7	16.5	18.2	14.6	18.6	13.0	15.1	15.4
IPP	4.6	0.3	4.7	0.1	4.7	3.7	2.6	2.3
Customer Driven Total	155.2	179.9	163.1	224.2	164.6	227.7	231.9	234.0
System Expansion and Improvement	69.1	45.4	69.8	63.0	44.4	77.4	67.5	50.0
Uneconomic Extension Assistance	0.4	0.8	0.5	0.3	0.5	0.6	0.6	0.6
Growth Total	224.7	226.1	233.4	287.5	209.5	305.7	300.0	284.6
Distribution Sustain								
System Expansion and Improvement	49.4	66.5	29.7	92.8	55.1	62.4	56.6	59.4
Asset Replacement								
Poles	81.7	94.5	77.3	79.5	74.0	74.9	76.1	63.3
Overhead Equipment	11.1	10.9	11.4	7.1	15.8	9.3	14.4	15.6
Underground Equipment	30.9	33.9	29.5	32.5	30.3	26.0	21.6	19.4
Trouble	10.5	17.0	10.8	21.5	11.0	17.3	17.7	18.0
Asset Replacement Total	134.3	156.3	128.9	140.7	131.0	127.5	129.8	116.3
Beautification	1.4	1.7	1.4	1.7	1.5	1.0	1.1	1.1
Sustain Total	185.1	224.6	160.0	235.1	187.6	190.9	187.5	176.8
Total Distribution	409.8	450.6	393.4	522.7	397.1	496.6	487.5	461.4
Less: Contribution in Aid	(76.6)	(122.9)	(78.4)	(140.6)	(80.3)	(129.8)	(134.0)	(133.7)
Total Net	333.2	327.7	315.0	382.1	316.8	366.8	353.5	327.7

Table 6-44 Distribution Actual and Plan Capital Additions Fiscal 2017 to Fiscal 2021

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Distribution Growth								
Customer Driven								
Customer Connections	132.8	158.0	139.9	178.1	141.3	210.9	214.0	216.2
Major Customer Connections	17.8	16.6	18.1	3.1	18.5	12.1	9.9	20.7
IPP	3.7	0.7	4.7	0.1	4.7	6.9	2.6	2.4
Customer Driven Total	154.4	175.3	162.7	181.3	164.5	229.8	226.5	239.3
System Expansion and Improvement	35.0	57.3	78.5	49.9	64.0	74.9	79.8	104.3
Uneconomic Extension Assistance	0.4	0.2	0.5	1.0	0.5	0.5	0.6	0.6
Growth Total	189.8	232.7	241.7	232.2	229.0	305.2	306.9	344.2
Distribution Sustain								
System Expansion and Improvement	44.3	59.6	26.5	65.6	51.9	92.1	64.8	76.3
Asset Replacement								
Poles	82.0	88.6	78.1	92.7	74.6	74.1	75.9	65.9
Overhead Equipment	10.3	10.3	11.3	8.4	14.9	8.8	13.4	15.4
Underground Equipment	33.8	22.7	29.6	30.4	30.1	28.1	22.5	19.8
Trouble	10.5	6.1	10.7	14.3	10.9	18.2	17.6	18.0
Asset Replacement Total	136.6	127.7	129.8	145.8	130.6	129.2	129.4	119.1
Beautification	1.4	1.0	1.4	1.9	1.5	1.0	1.1	1.1
Sustain Total	182.3	188.3	157.7	213.3	184.0	222.3	195.3	196.5
Total Distribution	372.1	421.1	399.3	445.4	413.0	527.5	502.2	540.7
Less: Contribution in Aid	(76.0)	(79.7)	(78.3)	(113.0)	(80.2)	(129.2)	(131.0)	(136.6)
Total Net	296.1	341.4	321.0	332.4	332.8	398.3	371.2	404.1

6.4.15.1 Distribution Growth Capital Expenditures and Additions

Customer Driven Expenditures

Customer driven expenditures include expenditures to connect residential and commercial load customers (approximately 5,000 design connections and 35,000 simple “express” connections annually), major distribution loads (defined as greater than 5MVA and/or $2 million in interconnection costs) and distribution voltage IPP projects.

Customer driven expenditures are forecast based on historical levels while additions are forecast based on the assumption that most expenditures are capitalized in the year they are incurred. The Customer Capital program is driven by customer connection requests that are “unplanned” projects. The level of economic activity in the province is the single largest influence on the customer capital expenditures.

Housing starts, infrastructure investment, and new industries such as cannabis grow operations have contributed to an unprecedented construction boom over the last three years and therefore unprecedented volumes of distribution customer connection requests. Simple express connections volumes, which are a good indicator of overall customer activity, have risen from 25,536 requests in 2015 to 36,413 in 2018. This has resulted in a customer capital program that is seeing atypical growth year upon year, with customer capital expenditures growing from $170.49 million in fiscal 2016 to a forecast of $234 million in fiscal 2019. Cost increases for materials and civil labour also contribute to higher expenditures.

Annual capital additions are forecast to increase in fiscal 2020 to fiscal 2021 from $232 million to $234 million. Annual capital expenditures are forecast to increase in the test period from $227 million to $239 million due to adjustments for inflationary effects on labour and materials.

There are currently five known customer driven projects greater than $5 million with expenditures in the test period, and the projects are listed in Table 6-45 below. More information on the projects listed can be found in Appendix I, page 7, lines 1 to 5.

Table 6-45 Customer Driven Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Customer Driven				
DY-1543	Customer D	-	6.1	5.8	-
DY-1563	Customer E	-	5.1	3.3	1.7
DY-0981	Customer F	8.8	-	-	-
901241	Customer G	-	8.0	6.2	1.6
DY-1545	Customer H	-	-	3.5	1.8
	Projects & Programs Less than $5M	217.7	220.1	213.1	228.9
	TOTAL Customer Driven	**226.5**	**239.3**	**231.9**	**234.0**

System Expansion and Improvement - Growth

Growth driven system expansion and improvement expenditures address existing capacity constraints and anticipated load growth. BC Hydro is undertaking several projects to increase the capacity and transfer load at the highest risk locations. Table 6-46 below provides a summary of the fiscal 2020 to fiscal 2021 capital additions and capital expenditures. More information on the projects listed can be found in Appendix I, page 7, lines 6 to 19.

Table 6-46 System Expansion and Improvement Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	System Expansion and Improvement				
93639	12F51 & 53 HPN Voltage Conversion (LM-BBY-048)	-	8.3	3.9	-
93640	HPN 12F54, 72Q, 73Q, and 324 Voltage Conversion (LM-BBY-051)	5.3	-	5.3	-
900749	Bringing additional capacity from ARN to Tilbury (FV-FVW-057)	18.8	-	4.5	-
93669	Three new MLE Feeders to offload CBN (LM-FVE-607)	-	8.9	1.0	7.5
900306	HPN 77Q, 323, 326 and 327 Voltage Conversion Preparation (LM-BBY-062)	-	11.0	4.9	0.6
900307	LOH 12F68 Voltage Conversion and Transfer to HPN (LM-BBY-064)	5.7	-	1.7	-
900342	Voltage Conversion Prep for RIM Substation (LM-FVW-718)	-	7.3	2.3	3.6
900386	New MUR Circuit to Offload MUR 12F66 and MUR 12F84 (LM-VAN-020)	-	7.7	3.5	-
900446	WKA New Substation Bring 4 New Feeders (SI-KAM-001)	13.1	-	1.7	-
900452	DUG Extension Along Highway 1 East (SI-KAM-008)	5.5	-	0.5	-
94137	CBL New Feeder South Campbell River (VI-NVI-417)	6.4	-	6.0	-
901132	Two Fleetwood feeders to offload McLellan (FV-FVW-723)	-	13.3	5.7	7.0
901141	Lower Mainland - George Dickie Feeder Voltage Conversion (LM-VAN-066)	-	5.0	2.3	2.6
901253	George Dickie - Voltage Conversion preparation of 4F54, 4F61, 4F64 and 4F65 and cutover to Sperling 12F64 (LM-VAN-094)	-	-	0.6	2.9
	Projects & Programs Less than $5M	25.0	42.8	23.6	25.8
	TOTAL System Expansion and Improvement	**79.8**	**104.3**	**67.5**	**50.0**

This category of investments is subject to year over year fluctuations as a result of the prioritization of work to adjust to changes in the forecast load growth. The majority of capital additions and expenditures in this category are made up of the following categories:

- **New Feeders** - These are projects to construct new feeders and infrastructure to offload heavily loaded existing feeders or to supply distribution customer load growth. The significant areas of new feeder projects includes: Abbotsford, Delta, and Kamloops. BC Hydro is forecasting capital expenditures of $37 million in fiscal 2020 and $17 million in fiscal 2021 and capital additions of $52 million in fiscal 2020 and $37 million in fiscal 2021.
- **Voltage Conversions** - These are projects to convert the distribution primary voltage from 4 kV to 12 kV or from 12 kV to 25 kV. The objective of these investments is to increase existing distribution infrastructure capability to:
  - Enable transmission and substation plans for expansion or redevelopment requiring feeder loads to be transferred to other feeders or substations;
  - Increase system capacity to supply distribution customer load growth;
  - Increase operating flexibility for restoration and planned outages aligned with substation and transmission plans;
  - Increase system efficiency by reducing electrical system losses and improving customer service voltages;
  - Reduce congestion in heavily populated corridors; or
  - Minimize equipment additions and its environmental footprint.

The significant areas of voltage conversion within the test period includes: Vancouver, Burnaby, North Vancouver, Richmond and Surrey. BC Hydro is forecasting capital expenditures of $17 million in fiscal 2020 and $32 million in fiscal 2021, and capital additions of $6 million in fiscal 2020 and $57 million in fiscal 2021.

Uneconomic Extension Assistance

The Uneconomic Extension Assistance program is a legislated fund in the Electric Tariff (section 8.8) which provides financial assistance towards the cost of uneconomic distribution overhead electrical extensions requested by new connection customers to serve principal residences. Table 6-47 below provides a summary of the fiscal 2020 to fiscal 2021 capital additions and capital expenditures.

Table 6-47 Uneconomic Extension Assistance Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Uneconomic Extension Assistance				
	Projects & Programs Less than $5M	0.6	0.6	0.6	0.6
	TOTAL Uneconomic Extension Assistance	**0.6**	**0.6**	**0.6**	**0.6**

Annual capital additions and expenditures for Uneconomic Extension assistance are forecast to remain constant at approximately $0.6 million in fiscal 2020 and fiscal 2021, which is consistent with the fiscal 2017 to fiscal 2019 period.

6.4.15.2 Distribution Sustaining Capital Expenditures and Additions

System Expansion and Improvement - Sustain

System expansion and improvement sustaining expenditures maintain and improve distribution system performance including addressing customer reliability, safety risks and regulatory and legal requirements. Table 6-48 below provides a summary of the fiscal 2020 to fiscal 2021 capital additions and capital expenditures. More information on the projects listed can be found in Appendix I, page 7 lines 20 to 25 and Appendix J, page 118.

Table 6-48 System Expansion and Improvement Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	System Expansion and Improvement				
94143	QNL Voltage Conversion (NI-NC-160)	9.3	-	1.1	-
900557	H-Frame Elimination - Chinatown	13.9	3.7	13.9	3.7
900229	Takla Landing (NI-NEW-287)	9.1	0.2	0.5	0.2
900373	New DGR Circuit for Customer Vaults at Pacific and Howe (LM-VAN-004)	-	6.0	4.4	-
900374	New DGR Circuit for Customer Vaults at Drake and Howe (LM-VAN-005)	-	9.3	3.1	3.4
900391	Downtown Vancouver - Underground Murrin Feeders to Eliminate H-Frames in Gastown	4.4	13.2	4.4	13.2
	Projects & Programs Less than $5M	28.1	43.9	29.2	38.9
	TOTAL System Expansion and Improvement	**64.8**	**76.3**	**56.6**	**59.4**

Year over year fluctuations are the result of prioritization of work with the timing of lower priority work being adjusted. Most of these investments are for various small projects that relate to the following three areas;

- **Customer Reliability** - The objective of customer reliability expenditures is to improve reliability on targeted distribution circuits that are performing poorly. The scope of customer reliability projects may include new standby feeders, feeder ties, as well as circuit undergrounding or reconfiguration, line relocations and protection upgrades. BC Hydro is forecasting capital expenditures of $3 million in fiscal 2020 and $2 million in fiscal 2021, and capital additions of $2 million in fiscal 2020 and $4 million in fiscal 2021.
- **Distribution Automation** - Automation of distribution devices provides operating personnel with remote visibility of system parameters and system status, facilitates remote operability, and in general enables greater flexibility to efficiently operate the system. Expenditures are focused on automation of reclosing and switching devices to enable faster fault isolation and outage restoration, thereby enhancing service reliability, and on automation of voltage management devices to improve power quality. BC Hydro is forecasting

expenditures of $20 million in fiscal 2020 and $18 million in fiscal 2021, and capital additions of $21 million in fiscal 2020 and $20 million in fiscal 2021.

- **Downtown Vancouver Redevelopment** - The Downtown Vancouver Redevelopment Plan is a long-term strategic plan, aligned with the Downtown Vancouver Electric Supply plan described in Appendix K, to convert the downtown core from a 12 kV dual-radial system to a 25 kV open loop system over the next 30-plus years. The Cathedral Square transformer failure in 2007, the manhole fire in 2008, and the Murrin transformer failure in 2013 have demonstrated the considerable supply risk and vulnerability of the aging and congested distribution system in the Downtown Vancouver area. This initiative will start to address the risk of long, high consequence outages in the downtown area. The Plan will replace assets in poor condition with equipment that meets current standards and will introduce automation to provide operational flexibility, reduce congested circuits and reduce outage restoration times. In conjunction with the Downtown Vancouver Redevelopment, BC Hydro will continue with a safety initiative in Downtown Vancouver to eliminate potential hazards to the public. The replacement circuits will be an underground automated open loop system to align with the overall redevelopment initiative. BC Hydro is forecasting expenditures of $31 million in fiscal 2020 and $20 million in fiscal 2021, and capital additions of $24 million in fiscal 2020 and $32 million in fiscal 2021.

Asset Replacement

Distribution asset replacements expenditures address equipment that has reached end of life. The forecast level of capital expenditures and additions for Asset Replacements ranges between $116 million and $130 million annually during the test period and is lower than the fiscal 2017 to fiscal 2019 period. Higher levels of investments in fiscal 2016 to fiscal 2019 have addressed a backlog of assets that have been assessed to be in Poor or Very Poor condition and are at, or approaching, end of life.

Table 6-49 below provides a summary of the fiscal 2020 to fiscal 2021 capital additions and capital expenditures. More information on the projects listed can be found in Appendix I, page 7, line 26 and Appendix J, page 120.

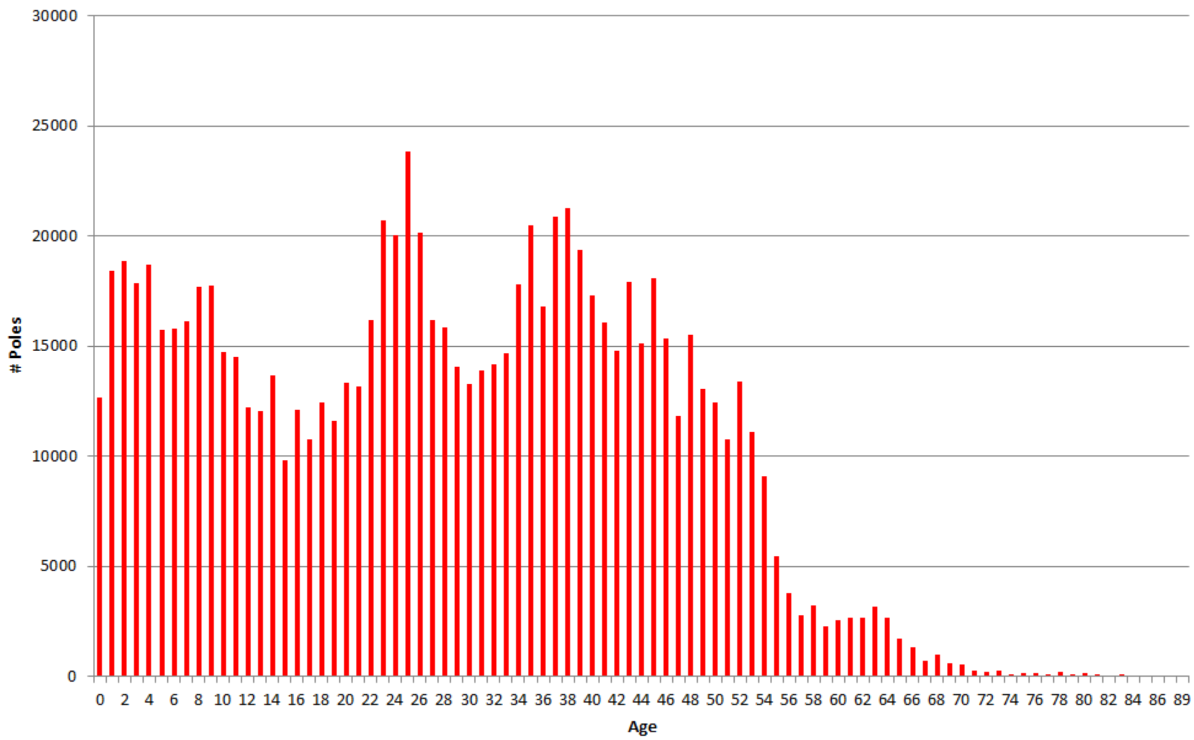
Table 6-49 Asset Replacement Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Asset Replacement				
900556	Various Sites - LED Street Light Conversion	3.8	5.8	4.8	6.1
	Projects & Programs Less than $5M	125.6	113.3	125.0	110.2
	TOTAL Asset Replacement	**129.4**	**119.1**	**129.8**	**116.3**

The majority of capital additions and expenditures in this category consist of recurring programs to address replacement of assets in the following four categories:

- **Poles** - This category covers wood and concrete poles as well as elevated platforms. Poles and platforms at end of life pose a significant risk to crews and the general public and may cause outages on the system. An increasing number of BC Hydro’s approximately 900,000 distribution system wood poles are reaching end of life. More than 96,000 poles are currently greater than 50 years of age compared to 67,000 units that were greater than 50 years of age in fiscal 2014. Overall, from fiscal 2014 to fiscal 2019, the average age of wood poles increased from 28.2 years to 29.0 years. Figure 6-15 below shows the current wood pole age profile by years of age.

Figure 6-15 Current Wood Pole Age Profile



Wood pole end-of-life is identified by a series of inspection programs that run throughout the fiscal year. In the test period, approximately 16,000 wood poles will be replaced. Concrete poles were first installed on the distribution system in the early 1980s. Due to safety issues related to a lack of adequate integral bonding, BC Hydro is replacing all concrete poles. In the test period the remaining concrete poles will be replaced with wood poles. BC Hydro is forecasting expenditures of $76 million in fiscal 2020 and $63 million in fiscal 2021 after recoveries from Telus.

- ***Underground System* -** Underground system assets include feeder cables, submarine cables, residential distribution cables and equipment, transformers and switchgear. Underground systems typically supply densely populated areas. Equipment in poor condition can pose a significant risk to system reliability and to public and worker safety. Detailed condition assessments combined with risk assessments are used to identify replacements of underground system assets. An example is the replacement of live-front transformers, which were installed in the 1960s. Inspections have identified some units that need to be replaced because perforations are developing in the unit enclosures due to corrosion. These openings in the enclosure are significant electrical hazards for the public. In addition to corrosion issues, live-front equipment creates a higher safety risk for workers and is being replaced in order to meet BC Hydro's current safety standards. All remaining live-front transformers are being replaced over the next four years with dead-front units which provide additional safety barriers for workers and the public. Transformers and switchgear with polychlorinated biphenyl (**PCB**) levels at or above 50 ppm are being proactively replaced to ensure all units in the category are removed by the December 31, 2025 Federal Polychlorinated Biphenyl Regulation deadline. BC Hydro will spend $22 million in fiscal 2020 and $19 million in fiscal 2021 to address end of life replacements on the underground system.

- ***Overhead System* -** Overhead system assets include transformers, voltage regulators, circuit reclosers, conductor, and switches including porcelain fuse cut-out switches. Porcelain fused cut-out switches, which are prone to failing, posing a significant falling object safety hazard to workers and the public, will continue to be replaced at a rate of approximately 6,000 units over the test period. The replacement program started in fiscal 2010. BC Hydro also manages a fleet of street lights as part of the distribution overhead system. A five year deployment of light-emitting diode street lights is planned to begin in fiscal 2020 to replace the current fleet of existing high pressure sodium units. Equipment on the overhead system with polychlorinated biphenyl (**PCB**) levels at or above 50 parts per million (ppm) is being proactively replaced to ensure all units in the category are removed by the December 31, 2025 Federal Polychlorinated Biphenyl Regulation deadline. BC Hydro will spend $14 million in fiscal 2020 and $16 million in fiscal 2021 to address end of life replacements on the overhead system.

- ***Trouble*** **-** Trouble capital expenditures are for equipment replacements that meet capitalization rules and resulting from: routine trouble calls, which are day to day restoration of power outages; storms, which are events causing outages over a large geographic area or affecting a large number of customers, or is of extended duration; or damage to plant, which are events where a third-party may be liable for the cost of the system repairs. BC Hydro and contractor crews respond to about 55,000 dispatched calls per year regarding the distribution system. The forecast expenditures are based on historical levels. BC Hydro is forecasting expenditures of $18 million in fiscal 2020 and $18 million in fiscal 2021 to respond to trouble calls.

Beautification

BC Hydro assists municipalities with financial support through the Beautification Program. BC Hydro provides one-third of the cost of converting overhead facilities to underground for select projects in urban municipal areas. The purpose of the fund is to help municipal governments achieve their environmental and community improvement objectives such as:

- Minimize or eliminate environmental concerns;
- Improve visual aesthetics; and
- Accommodate public redevelopment projects.

The forecast expenditures will be offset by contributions from the municipalities by two-thirds.

Table 6-50 Beautification Plan Capital Additions and Expenditures Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2020	Capital Additions Plan F2021	Capital Expenditures Plan F2020	Capital Expenditures Plan F2021
	Beautification				
	Projects & Programs Less than $5M	1.1	1.1	1.1	1.1
	TOTAL Beautification	**1.1**	**1.1**	**1.1**	**1.1**

Annual capital expenditures and additions are driven by the number of projects submitted to the program by municipalities. Capital expenditures and additions across the fiscal 2017 to fiscal 2021 period remain below $2 million per fiscal.

Contributions in Aid

Contributions in Aid are periodic or lump-sum payments or consideration received from customers or third parties to provide funding toward the cost of construction or acquisition of an asset, where the asset ownership, operation and maintenance responsibilities remain with BC Hydro. Distribution Contributions in Aid are mostly received under the Customer Driven Program for new connection requests in accordance with the Electric Tariff. Contributions in Aid are also received under the Beautification and Uneconomic Extension Assistance programs. All three programs are discussed above.

Distribution Contributions in Aid are forecast to increase from fiscal 2020 to fiscal 2021 together with the increase associated with customer driven investments.

6.5 Technology Capital Investments

The Technology KBU is responsible for the planning, design, delivery and operation of BC Hydro's information technology systems as well as a number of operational technology systems.

BC Hydro has made many improvements to the management of its technology capital program since the Previous Application. These improvements include:

- **Improved business case process:** Clear guidance is provided through the Technology business case development process so that business cases include alternative courses of action, comparison tables and trade-off analysis, as well as the articulation of financial and non-financial benefits, including metrics with baselines, targets, and details on how and when benefits are to be measured;
- **Improved program delivery governance:** Capital program delivery governance has been improved through ongoing monitoring by the Capital Delivery Management Committee. This process includes management of budget re-allocation and ex-plan requests, as described in section 6.3.5 above;
- **Improved delivery performance:** Our capital delivery performance has improved. From fiscal 2016 to fiscal 2018, a total of 94 projects were completed, with total approved first full funding of $135.1 million and total actual costs of $134.5 million - a favourable variance of $0.6 million or 0.4 per cent. These variances are an improvement over the prior test period and compare favourably to industry results. The Project Management Institute's Pulse of the Profession Report stated in its global project management survey that 57 per cent of technology projects are completed on budget; and
- **New benefits realization process:** To address the BCUC's SAP Inquiry recommendations and to meet commitments made during the Previous Application proceeding, BC Hydro has developed a benefits realization process

for identification and tracking of benefits arising from business driven technology projects. This is described further in section 6.5.5 below.

6.5.1 Overview of Technology Capital Assets and Key Drivers

BC Hydro's business requires an extensive technology portfolio, and ongoing investment is critical. Our forecast investments fall into three categories, which correspond with the key drivers of technology investment:

- Manage compliance and security;
- Manage risk and sustain productivity; and
- Enhance business capability.

Each of these categories is explained further below.

6.5.1.1 Ongoing Technology Investment is Key to the Day to Day Operations of BC Hydro

BC Hydro's technology systems provide important support to the organization's day-to-day operations, and include data centres, networks, enterprise and business group applications, mobile phones and mobile applications, geographic information systems, personal devices and desktop software, cyber security devices and monitoring applications, business intelligence and analytics platforms, and a subset of the energy management systems.

Our technology assets are located in two active data centres and two control centres, which together hold approximately 2,500 servers as well as network switches, firewall components, storage and backup systems. Additional assets include software platforms and related licenses, approximately 300 applications and related licenses, approximately 8,200 desktop and laptop computers, and approximately 4,800 mobile phones. In addition, all major BC Hydro facilities have local area networks and BC Hydro has mobile WiFi in 900 fleet vehicles. These assets are maintained through a combination of vendor product support agreements and sustainment investments.

6.5.1.2 Fluctuations in Technology Investment Result from Project Timing, Emergent Priorities and Changes in Business Requirements

While sustained investment in technology is required, the level of investment varies from year to year in response to project timing, emergent priorities and changes in underlying business requirements.

From fiscal 2016 to fiscal 2018, actual average annual Technology capital expenditures were $75 million. Capital expenditures are forecast to be $87.8 million in fiscal 2019 and are planned to be $93.5 million in fiscal 2020. These increased amounts primarily reflect the implementation of the Supply Chain Applications project.

In fiscal 2021, planned capital expenditures decrease to $55 million. This reflects a focus on investments to manage compliance and security and to manage risk and sustain productivity. Additional investments to enhance business capability, as identified and required, will be considered through funding re-allocations and the ex-plan process, which is further described in section 6.3.5.

6.5.2 Three Technology Investment Categories Correspond with Key Drivers

BC Hydro's Technology Strategy and Five-Year Plan, provided as Appendix L, provides guidance for capital investment in each of the three investment categories, described below. These categories correspond with the three main drivers of technology investment.

Table 6-51 below summarizes the key capital investment drivers within each investment category.

Table 6-51 Technology Investment Drivers by Category

Category	Driver
Manage Compliance and Security	**Regulatory Compliance** (Compliance requirements) Investment requirement may come from regulatory bodies such as NERC, WorksafeBC, Canada Revenue Agency, etc. Reliability, safety or legislative requirements justify investment
	Product License Compliance (Contracts) Software licensing renewals or true-ups.
	Cybersecurity Risk (Excessive or increasing risk) Ever-changing threats and vulnerabilities
Manage risk and sustain productivity	**Technology Condition-Based Failure Risk** (Declining condition) Declining asset health increases asset failures. When the consequences are considered (under business-as-usual), a risk profile can be assessed, and value of risk mitigation may justify investment.
	Technology Performance-Based Risk (Declining performance) Obsolescence and declining utilization affect performance. When the consequences of performance problems are evaluated (under business-as-usual), a risk profile can be assessed, and value of risk mitigation may justify investment.
	Operational Risk (Excessive or increasing risk) Safety, Reliability, Environmental or Financial risk may justify investment.
	Reputational Risk (Excessive or increasing risk) Excessive or increasing reputational risk may justify investment.
	Business Growth (Increasing need for technology services) Expansion of technology services through load growth or higher demand for existing services.
Enhance Business Capability	**Enhanced Capability** (Need for new or significantly improved business function) Demand for new capabilities enabled by technology, typically related to automation, business intelligence, communications, and new services.

6.5.3 Technology Capital Investment Planning

Technology capital investment planning includes both top-down and bottom-up processes. The Technology capital plan is guided by the top-down planning process described in section 6.3.2 and is included in the Enterprise planning and prioritization process, discussed in section 6.3.4.

BC Hydro developed the capital investment portfolio for the fiscal 2020 to fiscal 2021 test period using a three-step planning process. This process is designed to ensure our investments are in line with our priorities; that benefits, costs and risks justify investment, and that we are able to deliver on our plans. The process has been improved over the prior test period and future improvements are expected.

6.5.3.1 Step 1 – Identification of Investments

First, investments are identified for inclusion in the portfolio plan. The portfolio plan consists of active investments and new initiatives. Active initiatives are investments initiated in previous years and continue to be tracked through the various stages of execution. New initiatives are based on investment proposals. Each initiative is captured within the portfolio plan as a project, work program or acquisition. Each portfolio entry includes the name, description, prioritization assessment, investment score as well as forecast costs and risks and is accompanied by an Investment Justification document.

6.5.3.2 Step 2 – Formation of Draft Portfolio Plan

Second, once the capital portfolio entries have been fully captured and detailed, a draft portfolio plan is developed. Proposed initiatives are classified as mandatory, committed or prioritized and are then prioritized and subjected to constraints.

- **Mandatory initiatives** are required to meet security, safety, legal, regulatory or tariff compliance, and are not considered for prioritization.
- **Committed initiatives** are active investments and have either proceeded to the implementation phase, or are substantially committed as of the planning date. These initiatives are generally not considered for prioritization, due to cost or risk of undertaking a change in scope or schedule.
- **Prioritized initiatives** are prioritized using the enterprise-wide framework for capital prioritization, discussed in section 6.3.4 and by a technology specific investment score. These scores provide guidance into the development of the portfolio plan, within the enterprise funding allocation.
- **Constraints** include delivery and oversight capacity, business capacity for change, support capacity, technical dependencies and technology maturity. Time may also be a constraint, particularly if risk is expected to escalate, a window of opportunity exists, and/or if there are unmet dependencies.

6.5.3.3 Step 3 - Review, Refinement and Finalization

Third, a series of reviews are conducted on the draft portfolio plan to facilitate dialogue amongst Technology KBU management staff and affected BC Hydro business stakeholders. These reviews consider factors such as strategic alignment, portfolio value and risk and may result in the re-assessment of specific investments, re-design of programs or projects or shifting of timelines.

The Technology capital portfolio plan is dynamic in nature, and actual capital investments in the test period will likely differ for a number of reasons, including:

- Early stage Technology investment proposals include estimates which have a higher degree of uncertainty relative to later-stage business case estimates as technology choice, solution scope and scale, design and timing have not yet been fully examined; and
- Emerging and changing business priorities may require new technology solutions. For example, unplanned technology outages, increased technology risks, and unexpected loss of vendor support for products or services can all impact actual technology investments.

The Technology KBU oversees the implementation of its annual capital plans through monthly capital committee meetings of the Technology KBU leadership team. These committee meetings review portfolio plan variances, reallocate capital as needed, and manage risk adjustments.

6.5.4 Technology Portfolio Delivery Has Been Improved

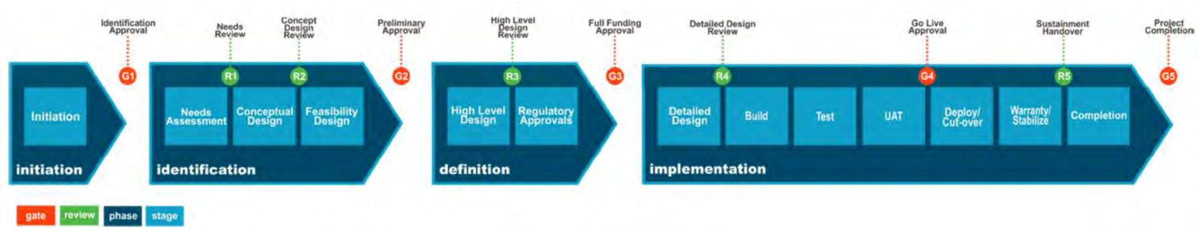
The capital investment portfolio consists of projects, work programs and acquisitions. Investments require approved business cases and adhere to a Technology-specific delivery framework called Information Technology Delivery Standard Practices (**ITDSP**).

6.5.4.1 We Use a Standard Technology Project Delivery Framework that Requires Approvals at Each Phase

ITDSP is used to aid managers, service providers and project teams in delivering successful technology projects. This framework was adopted in 2004 and is updated annually. The framework aligns with PPM Practices, which are discussed further in section 6.4.7 above, and has been adapted to better support the unique character of technology projects.

ITDSP uses standard PPM phases with uniquely defined stages. Gate approval points are positioned at the end of project stages so that management can confirm that the proposed project solution remains in alignment with business drivers, and is ready to progress to the next phase or stage. Each gate is a formal approval point, where key information is presented to the gate board, typically related to cost, schedule, scope, procurement, and risk.

Figure 6-16 Project Lifecycle Sequence from Project Initiation to Completion



The following sections provide a high level summary of the key activities within the project lifecycle phases.

6.5.4.2 Initiation Phase

The primary objective of the Initiation phase is the prioritization of a specific initiative and the decision to prepare a business case. To support the decision to initiate a project, the Project Initiator is responsible for assembling the following information:

- Brief description of the Problem or Opportunity;

- Key business drivers and any associated risks; and
- Estimated funding needs.

A decision is made to form and proceed with a project based on:

- The understanding of the problem or opportunity and the risk to the business;
- Support by the Project Initiator;
- The funding requirement; and
- The potential funding source.

The key outcomes of the Initiation phase are:

- An Identification phase business case;
- A detailed Identification phase project plan; and
- Firm Identification phase costs as well as an initial estimate on the overall project cost.

The Initiation phase concludes when the Identification phase business case is approved.

6.5.4.3 Identification Phase

The Identification phase includes three stages:

- **Needs Assessment** – to confirm the scope and business requirements.
- **Conceptual Design** – to review alternative solutions and select the leading alternative.
- **Feasibility Design** – to evaluate the feasibility of alternative solutions and recommended an alternative to be taken forward to the Definition phase.

The key outcomes of the Identification phase are:

- Approved and prioritized business requirements;
- An assessment of alternative solutions including a recommended solution and confirmed feasibility of the recommended solution;
- Completion of a Process Impact Assessment;
- A Definition phase business case;
- A detailed Definition phase project plan; and
- A firm Definition phase cost as well as a refined range estimate for the overall project cost.

The Identification phase concludes when a decision is made on whether to proceed to the Definition phase (the Preliminary Approval Gate).

6.5.4.4 Definition Phase

The Definition phase includes two stages:

- High Level Design/Blueprint; and
- Regulatory Approvals [312]

The objective of the Definition Phase is to carry out a detailed investigation of the selected alternative as well as to prepare a high level design, project implementation plan and an estimate of the Implementation phase funding, including an Implementation phase business case. This phase also includes securing all required regulatory approvals as well as any key defining agreements.

The key outcomes of the Definition phase are:

[312] Based on BC Hydro's current proposal in the Capital Expenditure Review Proceeding, the threshold for regulatory approvals is an estimated overall budget equal to or greater than $20 million. In these cases, the Project Managers work closely with the Regulatory and Rates KBU to receive regulatory advice.

- Process maps and definition documents;
- A High Level Design/Blueprint (documented in the Architecture Definition Document);
- An Implementation phase business case;
- An Implementation project plan; and
- A firm overall cost estimate range to complete the project.

The Definition phase concludes when a decision is made on whether to proceed to the Implementation Phase (the Full Funding Approval Gate).

6.5.4.5 Implementation Phase

The Implementation phase includes seven stages:

- Detailed Design;
- Build;
- Test;
- User Acceptance Testing
- Deploy/Cut-over;
- Stabilize; and
- Completion.

The objective of the Implementation phase is to complete the detailed design, build, test and commission the solution into service.

The key outcomes of the Implementation phase are:

- A working solution, confirmed through testing, that meets project objectives and is fully transitioned into operation; and

- A Project Completion Report measuring success against the approved business case.

The Go Live Approval Gate represents a decision on whether to proceed to the Deploy/Cut-over stage.

The project is considered complete once the Project Initiator and Project Sponsor have accepted the project results by signing the Project Completion and Evaluation Report.

6.5.4.6 Technology Work Programs and Licenses Are Subject to Work Flow Approval Processes

A Work Program is a program of high volume sustainment or enhancements items, typically with a low cost per item, which utilizes simple work flows on highly standardized and repeatable work units to deliver an overall benefit. Work Programs are typically set up for one fiscal year at a time, for a specific asset or group of assets. As this work is less complex, the ITDSP framework and project life cycle do not apply. Similarly, capital purchases for licences and equipment are also not subject to the ITDSP framework as they are not projects.

6.5.4.7 We Optimize Internal and External Resources

Technology employs two primary delivery models to optimize the use of internal and external market-based delivery capacity:

- Projects are primarily delivered through managed teams, where BC Hydro staff or consultant project managers manage blended teams of employees, vendors and individual contractors; and
- For larger, more complex projects, BC Hydro uses an outsourced model, called the system integrator model, where teams of external service providers provide project delivery and a large number of developer resources are applied to a project.

This resourcing model is appropriate to deliver the capital plan in the test period. The use of blended teams and system integrators allows for rapid scaling of our workforce, as required.

6.5.4.8 Technology Project Delivery Governance

Governance of technology capital delivery is provided by project steering committees, project gate reviews and funding approval, the Executive Team and the Board of Directors.

- Project steering committees provide senior management level direction to projects to assist with resolving complex issues.
- Project gate reviews occur at various points of the project lifecycle. Each gate is a formal approval point where key information on project cost, schedule, scope, procurement and risk is presented to the gate board.
- The Executive Team reviews the delivery portfolio on a monthly basis and approves projects greater than $6 million.
- The Board of Directors approves projects greater than $20 million.

Governance is also provided through BC Hydro’s Management and Accounting Policies, which are discussed in section 6.4.10.

6.5.4.9 Our Technology Project Delivery Performance Has Improved and Compares Well to Industry Results

Figure 6-17 and Table 6-52 below provide a summary of BC Hydro’s performance in delivering technology capital projects by comparing total approved first full funding for projects to total actual project costs.

Figure 6-17 Number of Technology Projects Completed Within Total Approved First Full Funding Amount

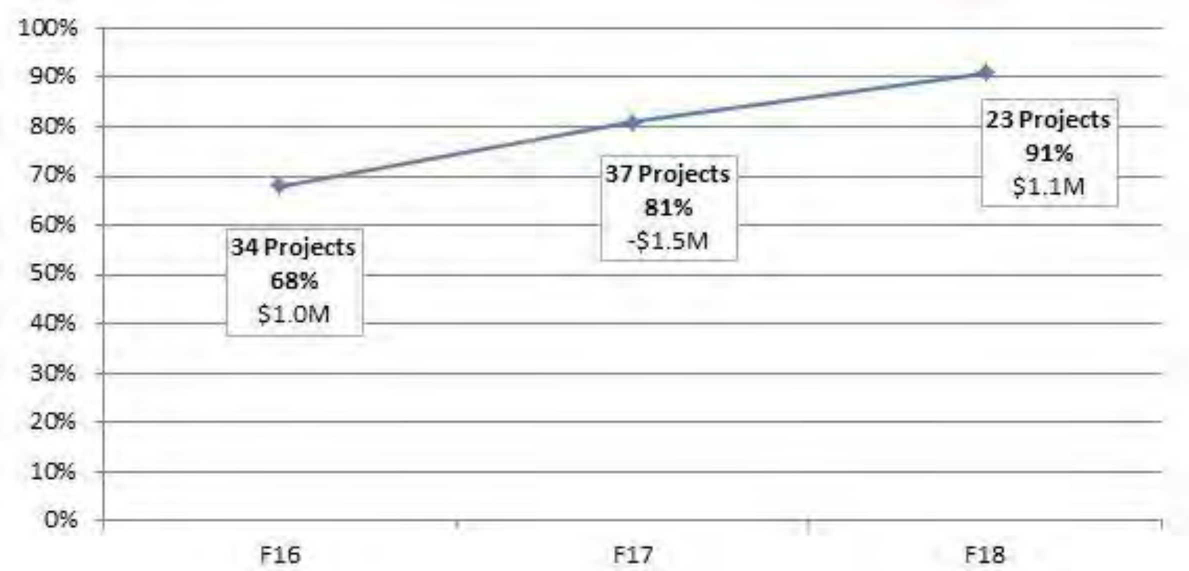


Table 6-52 Number of Technology Projects Completed Within Total Approved First Full Funding Amount

Fiscal Year	No. of Initiatives completed	Percentage of Initiatives Completed within FFF Amount	Cumulative Initiative Cost ($ million)		Variance	
			[A] FFF Amount ($ million)	[B] Actual Final Cost ($ million)	[A – B] ($ million)	[(B – A)/A] (%)
2016	34	68	42.0	41.0	1.0	2.4
2017	37	81	59.6	61.1	(1.5)	(2.5)
2018	23	91	33.5	32.4	1.1	3.3
Total	94		135.1	134.5	(0.6)	(0.4)

From fiscal 2016 to fiscal 2018, a total of 94 projects were completed, with total approved first full funding of $135.1 million and total actual costs of $134.5 million - a favourable variance of $0.6 million or 0.4 per cent.

These results indicate improvement over the period and compare favourably to industry results. The Project Management Institute's Pulse of the Profession Report stated in its global project management survey that 57 per cent of technology projects are completed on budget.

6.5.5 We Have Introduced a Technology Benefits Realization Process

Once a technology project is complete, newly implemented technology capabilities are expected to yield desired business outcomes and measurable benefits. These benefits may be diverse and apply to multiple KBUs. They may occur immediately or over time. BC Hydro has developed a benefits realization process so that benefits claimed in business cases are tracked and realized.

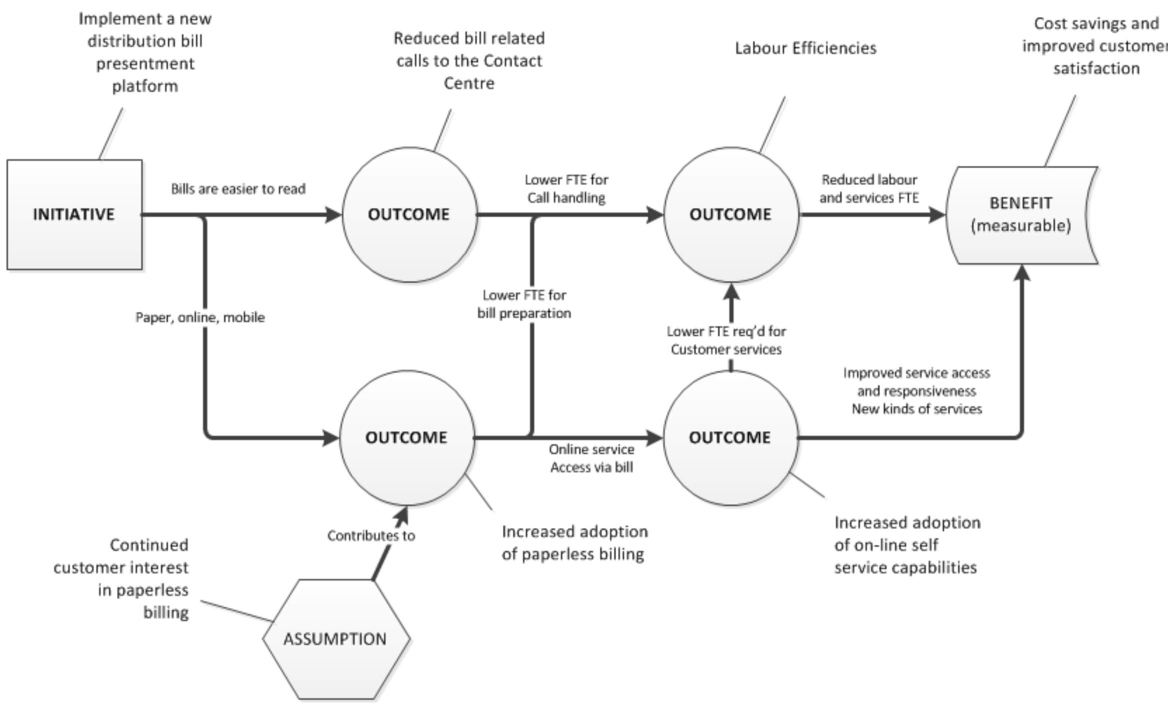
Each technology project has a business case which articulates the need, desired outcomes, and expected incremental benefits and costs. Cost estimates include upfront and ongoing costs, and expected benefits typically include risk mitigation and improved performance.

The use of financial measures such as net present value or return on investment may suggest certainty of financial benefits. For this reason, benefits are not often quantified in dollars, but are assessed using specific metrics that are easier to identify, predict and measure. The sponsor of each business case agrees to the costs and benefits outlined, including the timing of costs and benefits and how they will be measured.

This benefits realization methodology is being piloted on a number of BC Hydro's non-mandatory, business-driven technology initiatives with expected capital expenditures greater than $2 million. Selected benefits identified in each business case are tracked over the life of the asset, for an agreed period of time, or until all material benefits have been realized. Project initiators are required to document completion of outcomes and achievement of benefits on a quarterly basis, during project implementation and following project completion.

Figure 6-18 below provides an example of this approach. In this example, an initiative to implement a new distribution bill formatting platform results in a series of outcomes leading to measurable cost savings and improved customer satisfaction.

Figure 6-18 Benefit Realization Outcome Model (Illustration Only)



The actual outcomes and benefits from operation of a technology asset are tracked over a number of years.

Table 6-53 below identifies the projects selected for this benefits realization pilot in fiscal 2018. The pilot will continue, with additional projects in fiscal 2019 and throughout the test period.

Table 6-53 Benefits Realization Pilot Projects (Fiscal 2018)

Project	Status
Enterprise Billing Infrastructure Project (EBIP)	In Service
Field Access to Safety Information (FASI)	In Service
Fleet and Garage Management System (FGMS)	In Service
Supply Chain Applications (SCA)	Delivery

6.5.6 Technology Capital Expenditures and Additions

Technology capital expenditures and capital additions for fiscal 2017 to fiscal 2021 are presented in Table 6-54 and Table 6-55 below.[313]

Table 6-54 Technology Actual and Plan Capital Expenditures by Functional Category, Fiscal 2017 to Fiscal 2021

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	Plan	Forecast	Plan	Plan
Manage Compliance and Security	12.7	12.5	8.2	13.0	9.6	11.6	14.8	8.1
Manage Risk and Sustain Productivity	70.0	46.0	47.8	38.3	38.6	59.8	68.8	53.1
Enhance Business Capability	13.7	16.4	46.5	19.1	26.4	40.0	34.4	4.8
Total Gross	96.4	75.0	102.5	70.4	74.7	111.3	118.1	66.0
Portfolio Adjustment	(15.1)		(10.2)		1.5	(16.8)	(24.6)	(10.5)
Total Net	81.4	75.0	92.4	70.4	76.2	94.5	93.5	55.5

Table 6-55 Technology Actual and Plan Capital Additions by Category, Fiscal 2017 to Fiscal 2020

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	Plan	Forecast	Plan	Plan
Manage Compliance and Security	16.5	13.3	8.2	9.2	9.6	7.9	19.7	7.6
Manage Risk and Sustain Productivity	72.6	57.8	72.2	51.1	40.1	54.8	72.6	65.7
Enhance Business Capability	7.6	5.9	19.7	11.0	72.5	10.4	73.3	12.3
Total Gross	96.7	77.0	100.0	71.2	122.2	73.1	165.6	85.5
Portfolio Adjustment	(17.6)		(9.9)		(12.2)	(6.4)	(24.6)	(10.5)
Total Net	79.1	77.0	90.1	71.2	110.0	66.7	141.0	75.0

The following lists the categories of planned capital expenditures and additions in the test period.

[313] Fiscal 2017 and fiscal 2018 variances greater than $10 million are described in Appendix G, section 5.

6.5.6.1 Investment to Manage Compliance and Security

Table 6-56 Manage Compliance and Security - Plan Capital Expenditures and Additions for Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Addition Forecast F2020	Capital Addition Forecast F2021	Capital Expenditure Forecast F2020	Capital Expenditure Forecast F2021
	Manage Compliance and Security				
	Projects Over $2 million				
T001549	End of Life Firewall Replacement	3.6	-	2.0	-
T001390	Data Centre Network Security Improvement	2.5	-	2.0	-
T002055	NERC CIPv7	2.3	-	2.3	-
	Programs over $2 million				
T001913	Microsoft Enterprise Agreement True Up F2020-F2021	2.0	2.0	2.0	2.0
T001909	Infrastructure Software F2020-F2021	1.7	1.8	1.7	1.8
	Projects and Programs less than $2 million	7.7	3.8	5.0	4.3
	TOTAL Manage Compliance and Security	19.7	7.6	14.8	8.1

More information on the projects listed above can be found in Appendix I, page 9, lines 1 to 5.

- The End of Life Firewall Replacement project is to upgrade critical network firewalls by identifying and replacing devices at end of vendor support;
- The Data Centre Network Security Improvement project is to assess gaps in the data network segmentation and implement security controls to more effectively segment the network;
- The NERC CIPv7 project is to implement access controls for low impact cyber systems, security requirements for certain portable devices and policies for reliability-related emergencies;
- Microsoft Enterprise Agreement True Up F20-F21 is an annual capital purchase of incremental desktop and server product licenses. Server products include Windows Server, Exchange, Sharepoint, SQL Server, CRM, and others; and

- Infrastructure Software F20-F21 is an annual purchase of incremental perpetual software licenses for personal computers, servers and other assets for products from vendors such as Adobe, Microsoft, VMWare, Symantec, IBM and Oracle.

6.5.6.2 Investment to Manage Risk and Sustain Productivity

Table 6-57 Manage Risk and Sustain Productivity - Plan Capital Expenditures and Additions for Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Addition Forecast F2020	Capital Addition Forecast F2021	Capital Expenditure Forecast F2020	Capital Expenditure Forecast F2021
	Manage Risk and Sustain Productivity				
	Projects over $2 million				
T001577	HydroShare HydroWeb Upgrade	7.3	-	3.3	-
T001397	Contact Centre Technology Foundation Refresh	-	6.4	3.2	3.2
T001070	CIDC Network Refresh	-	6.0	4.5	-
T001379	SAP HANA-ECC Upgrade	-	6.0	-	6.0
T001105	Next Generation Desktop (Windows 10)	4.8	0.9	2.8	0.9
T001877	GE Smallworld GIS 5.x Upgrade	-	4.3	0.8	3.5
T002082	Meter Data Management System (MDMS) v9 Upgrade	3.8	-	3.0	-
T001723	Customer Connect Web Enablement	2.8	-	2.0	-
T002083	MDMS Improvements	0.8	1.5	0.8	1.5
T001402	LodeStar and Enhanced Billing System (Transmission)	2.2	-	0.6	-
T001719	SharePoint Workspaces Upgrade	-	-	-	2.5
	Programs over $2 million				
T001910	Server Sustainment (Capacity) F2020-F2021	4.0	4.5	4.0	4.5
T001663	PC Client Refresh F2019	0.3	-	0.3	-
T001911	PC Client Refresh F2020-F2021	4.5	4.2	4.5	4.2
T001912	Operations PC Inventory F2020-F2021	1.8	1.8	1.8	1.8
T001667	Storage Capacity Growth F2020-F2021	3.0	3.5	3.0	3.5
T001915	Provisioning of Mobile Devices F2020-F2021	1.8	1.8	1.8	1.8
T002067	Mobile Vehicle Wifi Refresh F2020	1.5	-	1.5	-
T002068	Mobile Vehicle Wifi Refresh F2021	-	1.8	-	1.8
	Projects and Programs less than $2 million	34.1	22.9	30.9	17.9
	TOTAL Manage Risk and Sustain Productivity	72.6	65.7	68.8	53.1

More information on the projects listed above can be found in Appendix I, page 9, lines 6 to 24.

- The Hydroshare HydroWeb Upgrade project is to upgrade SharePoint from version 2010 to 2016, and upgrade BC Hydro's primary, SharePoint-based intranet and extranet applications;
- The Contact Centre Technology Foundation Refresh project is based on retiring the existing call centre telephony infrastructure and replacing it with a new solution with improved reliability and increased capabilities;
- The Calgary Internet Data Centre (**CIDC**) Network Refresh project is to perform a complete upgrade of data centre infrastructure at BC Hydro's Calgary Internet Data Centre, including computing, storage and networking equipment;
- The SAP HANA-ECC Upgrade is to upgrade SAP to maintain vendor support and adhere to the BC Hydro enterprise application roadmap;
- The Next Generation Desktop (Windows 10) project is primarily to upgrade all BC Hydro personal computers to Windows 10;
- The GE Smallworld GIS 5.x Upgrade project is to upgrade the geographic information system (GIS) versions for the Distribution Analysis and Design, Spatial Asset Management, Geospatial Underground Locate System and PowerGrid applications. BC Hydro's GE Smallworld GIS platform supports a number of strategic and departmental solutions required for operation of the transmission and distribution system. The current GIS versions are no longer vendor-supported, resulting in increasing risk of unplanned outages for these solutions;
- The Meter Data Management System (**MDMS**) v9 Upgrade is to maintain vendor support;

- The Customer Connect Web Enablement project is to extend the existing online express connect capability by enabling online or mobile customers to submit, manage and receive feedback on their design connect applications;
- The Meter Data Management System Improvements project is to make various functional improvements to the Meter Data Management System, including improving the interface architecture with SAP.
- The Lodestar and Enhanced Billing System (Transmission) project is to retire the legacy Lodestar customer information system and supporting transmission bill generation capabilities, which will be replaced with SAP functionality and the recently implemented integration architecture and bill generation solution;
- The SharePoint Workspaces Upgrade project is to modernize and potentially integrate the PPM Workspace and Supply Chain Workspace SharePoint applications, providing upgraded and improved document management and collaboration capabilities;
- The Server Sustainment (Capacity) work program is for the procurement of equipment for the sustainment of Windows and Unix servers at BC Hydro's Kamloops Internet Data Centre (**KIDC**);
- PC Client Refresh is an annual refresh program to replace a subset of the personal computers used by BC Hydro employees for business purposes that are due for replacement;
- Operations PC Inventory is an annual refresh program to for employee personal computers used for business purposes, which require replacement and for new employees requiring a personal computer for business purposes;
- The Storage Capacity Growth work program is for storage expansion at the Kamloops Internet Data Centre, and Fraser Valley Operations centre to meet business application needs;

- Provisioning of Mobile Devices is an annual replacement program for employee smart phones used for business purposes, which require replacement and for new employees requiring a smart phone for business purposes; and
- Mobile Vehicle Wifi Refresh is an annual program to refresh end-of-life Mobile Vehicle WiFi equipment deployed in BC Hydro vehicles to provide field crews with mobile access to BC Hydro's data network.

6.5.6.3 Investment to Enhance Business Capability

Table 6-58 Enhance Business Capability - Plan Capital Expenditures and Additions for Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Addition Forecast F2020	Capital Addition Forecast F2021	Capital Expenditure Forecast F2020	Capital Expenditure Forecast F2021
	Enhance Business Capability				
	Projects Over $2 million				
T001127	Supply Chain Applications	57.4	-	19.0	-
T001851	Stations Work Planning, Scheduling and Work Execution	-	6.4	3.5	2.5
T001637	Asset Investment Planning Tool	-	-	4.2	1.0
T001611	Autodesk Substation Design Suite	2.4	-	0.9	-
T001035	Dam Safety Information System (DSIS)	-	2.2	1.0	0.9
T000625	Fleet Telematics	-	2.2	1.8	0.1
	Programs over $2 million				
	Projects and Programs less than $2 million	13.5	1.5	4.0	0.4
	TOTAL Enhance Business Capability	73.3	12.3	34.4	4.8

More information on the projects listed above can be found in Appendix I, page 9, lines 25 to 30 and Appendix J, page 121.

- The Supply Chain Applications Project is to address process and technology capability gaps, achieving operational efficiencies, reduced material and service costs and an overall reduction in risk;

- The Stations Work Planning, Scheduling and Work Execution project is to allow the Operations Business Group to better accept, bundle, schedule, and execute weekly asset work for a proposed mobile workforce, leading to efficiency gains;
- The Asset Investment Planning Tool project is to enable a consistent, transparent and more objective approach to asset investment planning and management across BC Hydro, leading to improved investment decisions and results;
- The Autodesk Substation Design Suite project is to modernize Generation and Transmission Engineering's substation design work processes to reduce the time it takes to prepare detailed designs and to improve the accuracy of design information, technical collaboration capability, and the quality and efficiency of creating construction work packages;
- The Dam Safety Information System project is to consolidate data from many sources and provide a single interface for Dam Safety Surveillance Engineers to view the conditions of BC Hydro dams; and
- The Fleet Telematics project is to implement a vehicle telematics system that will help to manage capital and operating costs, availability, utilization, and safety related to all BC Hydro vehicles.

6.6 Properties Capital Investments

The Properties KBU is responsible for the supply, operations and maintenance of BC Hydro's headquarters and field offices, which total 101 facilities, comprising approximately 3 million square feet of office and industrial space. These facilities house field crews as well as a wide range of critical functions including system operations, telecommunications, emergency operations, customer contact, materials management, fleet management, and security command centers. BC Hydro's headquarters and field offices provide critical services to BC communities and local industry and must be operational for 24-hour response in all conditions, similar to other emergency services facilities (e.g., fire halls). Facilities managed by the Properties KBU do not include Generation plant buildings or Transmission and Distribution substations, which are included in the Generation and Transmission and Distribution capital plans, respectively.

6.6.1 Properties Portfolio Investments Address Risks and Issues with Existing Assets

The investments in the Properties portfolio are driven by the need to address the issues and risks associated with the existing physical assets and infrastructure. Properties capital investments fall into two general categories:

- **Building Development** - projects include the major refurbishing or rebuilding of field buildings in areas where BC Hydro’s existing facilities are at end of life and/or inadequate to meet operational needs; and
- **Building Improvement** - projects at existing facilities to address operational deficiencies as well as end-of-life replacements of aging building components and systems.

Properties Capital Planning focuses on assessing the health of existing assets and determining operational requirements that cannot be met by the existing asset portfolio, to establish an effective long term capital plan.

Aging Assets

Facilities managed by Properties are, on average, 33 years old, with more than forty per cent of the facilities being greater than 40 years old. Continued investment in these assets in the test period and beyond is required to maintain efficient and effective operation of BC Hydro’s building assets, to limit costly and disruptive failures and to achieve the organization's objectives. All Properties’ projects are classified as Sustaining Capital.

Asset Health

Properties assesses the health of more than 12,000 individual assets at the 101 BC Hydro facilities managed by Properties, based on each asset's current condition (including each facilities seismic withstand), remaining life expectancy, likelihood of failure, and impact of failure. These assets include building envelopes, roofs, HVAC systems, elevators, etc. The results of these assessments identify assets that are at or near end of life. Investments in these assets are considered for inclusion in the capital plan.

Operational Requirements

Properties seeks feedback from key occupant groups in order to capture each group's building-related requirements across the portfolio. These occupants assess their facilities for their ability to meet their operational priorities. This feedback results in proposed investments to address specific operational demands including, for example, inadequate office and operational space, insufficient material storage space, and undersized truck bays.

6.6.2 Properties Bottom – Up Asset Capital Planning Process

The Properties planning process follows a three step bottom-up approach.

Step 1 – Identify the Asset Needs

The first step of this process is to identify the building and asset needs at each of the facilities that should be considered for remediation. This assessment includes reviews of existing asset issues and risks as well as asset condition assessments. This results in a list of proposed projects.

Step 2 – Formation of a Draft Capital Plan

The proposed projects are categorized, ranked by priority and then subjected to any funding constraints, in order to develop a draft capital plan.

Step 3 – Review the Investments in the Capital Plan Period

The draft plan then undergoes a series of reviews of the planned investments across the building portfolio to ensure that investments are appropriately prioritized and timed. This review also allows for validation of the operational requirements by Properties and BC Hydro operations and other KBUs. These reviews may result in a re-assessment of specific projects, or shifting of projects within or beyond the capital plan period.

Properties proposed capital investments are subject to the BC Hydro enterprise-wide framework used to assist in prioritizing capital investment. Investments included in the BC Hydro 10 Year Capital Forecast are selected based on their prioritization score and other constraints, following the BC Hydro enterprise-wide process. Further information is provided in section 6.3.4 above.

Additional information on the Properties capital expenditures for the fiscal 2020 to fiscal 2021 test period is provided in Appendix I, page 10, lines 1 to 7 and Appendix J, pages 123 to 127.

6.6.3 Properties Capital Investment Delivery Aligns With BC Hydro's Standard Approach

The Properties Group will deliver approximately $114 million of BC Hydro's capital expenditures over the test period. The delivery of Properties' capital projects are managed using both internal and external (contracted) resources following normal building construction industry practices. Properties' Capital Delivery processes align with the standard BC Hydro project lifecycle for managing projects, whereby:

- Projects progress through the four phases of delivery: Initiation, Identification, Definition, and Implementation; and
- Gate approvals are formal approval points positioned at the end of key stages in the project lifecycle to allow management to confirm that the proposed

project solution remains in alignment with business drivers and that the project is delivering on key project objectives including cost, schedule, and scope.

6.6.4 Properties Capital Expenditures and Additions

Table 6-59 Properties Actual and Plan Capital Expenditures Fiscal 2017 to Fiscal 2021[314]

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Properties								
Interior Space Renovations	11.6	11.4	11.9	9.9				
Building Development	54.8	48.0	44.4	25.2	69.5	23.7	37.8	39.7
Building Improvements and Other	26.3	23.1	18.8	28.4	18.8	19.8	21.1	15.6
Other Properties	3.0	4.1				-		
Total	95.7	86.6	75.0	63.5	88.3	43.5	58.9	55.3

Table 6-60 Properties Actual and Plan Capital Additions – Fiscal 2017 to Fiscal 2021[314]

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Properties								
Interior Space Renovations	21.6	19.2	11.9	12.1				
Building Development	4.6	8.4	87.5	81.4	6.7	8.9	18.9	40.0
Building Improvements and Other	38.2	26.5	18.8	30.0	18.8	19.8	21.1	15.6
Other Properties	3.9	0.7	-	3.4		-		
Total	68.3	54.8	118.1	126.9	25.5	28.7	40.0	55.6

Capital expenditures in fiscal 2019 are forecast to be $44.8 million below plan as several projects were deferred. The Materials Classification Facility project was put on hold for most of fiscal 2017 as capital funding constraints were being assessed across BC Hydro. This project has now recommenced, but with a delayed start date for construction. The Construction Services/Lower Mainland Transmission Facility project, the Dawson Creek Field Office project, and the Fleet Facility project were all deferred in fiscal 2017 for five years, and are now due to recommence in fiscal 2022 or fiscal 2023.

[314] Fiscal 2017 and fiscal 2018 variances greater than $10 million are described in Appendix G, section 5.

6.6.4.1 Building Development Projects

The planned capital expenditures and additions for fiscal 2020 to fiscal 2021 for Building Development projects are provided in Table 6-61, below.

Table 6-61 Building Development Projects Plan Capital Expenditures and Additions for Fiscal 2020 to Fiscal 2021 ($ million)

Planning ID	Name of Project	Capital Addition Plan F20	Capital Addition Plan F21	Capital Expenditure Plan F20	Capital Expenditure Plan F21
	Building Development				
P201701	Pemberton Field Building Redevelopment	11.0	-	4.8	0.0
P201601	Long Beach Field Building Redevelopment	7.9	-	5.8	0.0
P201702	Materials Management Building Redevelopment	-	11.9	6.2	1.1
P201703	Chilliwack Field Building Redevelopment	-	28.2	12.4	12.3
P201704	Materials Classification Facility Building Redevelopment	-	-	7.1	23.3
P201901	Kamloops Field Building Redevelopment	-	-	1.5	3.0
	TOTAL Building Development	**18.9**	**40.0**	**37.8**	**39.7**

Annual capital expenditures on Building Development projects are lower than in the previous test period, as funding pressures have resulted in the deferral of several projects beyond the test period.

6.6.4.2 Building Improvement Projects

The planned capital expenditures and additions for fiscal 2020 to fiscal 2021 for Building Improvement projects are provided in Table 6-62 below. There are approximately 30 individual projects planned over the test period, at locations across the province. These are grouped below by project type based on the asset categories the individual projects are addressing. The majority of these projects are less than $2 million.

Table 6-62 Building Improvement Projects Plan Capital Expenditures and Additions for Fiscal 2020 to Fiscal 2021 ($ million)

Name of Project Type	Capital Addition Plan F20	Capital Addition Plan F21	Capital Expenditure Plan F20	Capital Expenditure Plan F21
Building Improvements				
Building Envelope	0.4	2.4	0.4	2.4
Elevators	1.7	1.2	1.7	1.2
HVAC	4.0	2.7	4.0	2.7
Interiors	5.4	0.9	5.4	0.9
Life/Safety	0.4	-	0.4	-
Roof	0.7	3.2	0.7	3.2
Storage Buildings	6.1	3.7	6.1	3.7
Yard	2.4	1.6	2.4	1.6
TOTAL Building Improvements	**21.1**	**15.6**	**21.1**	**15.6**

Annual capital expenditures on Building Improvements projects are generally lower than in the previous test period, as funding pressures have resulted in the deferral of multiple projects beyond the test period.

The Interior Space Renovations project work at Dunsmuir and Edmonds offices was completed in fiscal 2018, with the renovation of the final floor at the Edmonds office being completed. Accordingly there are no future expenditures planned.

6.7 Fleet Capital Investments

Fleet is responsible for the acquisition, operational costs, maintenance and disposal of BC Hydro's 3,600 vehicle, trailer and equipment assets relied on by field crews and staff across the province to complete the organization's maintenance and capital work programs and support system reliability. The safety, reliability, and availability of vehicles and equipment are critical to ensure BC Hydro employees are able to safely and efficiently complete diverse types of planned and unplanned work, including restoration work during storms and emergencies.

6.7.1 Fleet Investments Are Managed Using Established Industry Principles and Practices

BC Hydro manages the lifecycle of diverse vehicle and equipment assets using established fleet industry principles and practices. These vehicle and equipment assets include light vehicles (cars, SUVs, pickups and compact vans), medium vehicles (flat deck and service body trucks, walk-in and heavy vans), heavy vehicles (bucket trucks, digger derricks, cranes, heavy flat decks, tractors, fire trucks, and dump trucks), trailers, forklifts, and other types of equipment (herein referred to as vehicles and equipment).The present average age of fleet assets is 5.9 years, with expected planned vehicle and equipment lifespans ranging from 10 to 15 years depending upon asset class.

6.7.2 Fleet Portfolio Investments

Investments in fleet assets are made to sustain reliable operations across the province, minimize total asset lifecycle costs, ensure fitness of given assets for evolving work purposes, and limit safety and operational risks by meeting safety and other regulatory requirements.

6.7.2.1 Vast Majority of Fleet Investments Are Replacements Rather than Upgrades

Fleet investments can be of two major types:

- Replacement of end-of-life vehicles and equipment to reduce financial risks, control lifecycle costs and address age-related mechanical, safety and reliability issues. These sustaining investments form the vast majority of the Fleet capital plan and seek to avoid financial risk of increasing maintenance costs as assets age, including the higher likelihood of costly unplanned maintenance events. It is important to continually maintain the composition of the fleet from the standpoint of average age in order to limit the build-up of high cost, older vehicles and equipment.

- Providing additional or upgraded fleet assets to improve operational productivity, flexibility and safety. This represents a very small portion of fleet capital investments and includes value-based vehicle and equipment purchases via the upgrading or the addition of new assets in response to changing business needs and work methods.

6.7.3 Fleet Assets Capital Planning Has Balanced Affordability and Operational Needs

Fleet Investment Capital Planning for the test period was guided by the principle of balancing affordability and vehicle reliability, while providing support to operate our system safely.

In its capital planning process, BC Hydro identifies and ranks vehicles and equipment for replacement using asset information (asset age/remaining life, mileage, maintenance costs, utilization rates, observed downtime frequency), input from fleet maintenance staff and end-users on asset condition, criticality and operational requirements. End-users also can identify requirements for upgraded or additional fleet assets. This information is used to assemble a list of vehicles and equipment for acquisition planning. The process is initiated in advance of the expected end-of-life replacement criteria (i.e., for a vehicle with a ten-year life replacement planning is started at approximately the seven year mark). The general fleet replacement criteria are established based on historical data, as well as the suggested useful life in a commercial application as determined by BC Hydro fleet data, industry benchmarks and vehicle manufacturers. In addition, the work application and the environmental conditions in which the assets are operated are considered as they have an impact on the actual life of the vehicle.

Through the Application of the enterprise-wide framework for capital prioritization, top-down planning and expenditure guidelines and other constraints, the list of vehicles for replacement, upgrades and vehicle additions are prioritized. Recommended acquisition plans are vetted through senior management.

During the test period, BC Hydro is planning to keep some fleet assets in service for longer periods, which will increase the average age of BC Hydro's fleet. The objective of this approach is to maximize the value of our existing assets to balance affordability and vehicle reliability. While increased asset age is expected to impact the overall condition of fleet assets, creating risks such as lower vehicle reliability and higher maintenance and operating costs, actions such as timely completion of routine preventative maintenance, implementation of fleet telematics and the creation of additional vehicle pools to increase asset utilization will help to mitigate these risks.

To-date, fleet aging has not resulted in a corresponding decline in BC Hydro's overall system performance or customer reliability. If BC Hydro begins to experience an unacceptable increase in fleet asset failures, options include adjusting the level of end-of-life replacement by redirecting funding from other parts of the BC Hydro capital investment portfolio or changing operational or maintenance practices. BC Hydro reviews its capital plan on a regular basis, providing an ongoing opportunity to adjust capital investments in order to respond to new information, including system performance, asset health and risks.

6.7.4 Fleet Capital Expenditures and Additions

Table 6-63 Fleet - Vehicle and Equipment Actual and Plan Capital Expenditures Fiscal 2017 to Fiscal 2021[315]

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Fleet	33.9	26.9	30.9	31.0	29.6	30.2	26.2	27.8

Table 6-64 Fleet - Vehicle and Equipment Actual and Plan Capital Additions Fiscal 2017 to Fiscal 2021[316]

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Fleet	40.3	38.2	32.4	29.8	30.2	30.2	26.2	27.8

[315] Fiscal 2017 and fiscal 2018 variances greater than $10 million are described in Appendix G, section 5.
[316] Fiscal 2017 and fiscal 2018 variances greater than $10 million are described in Appendix G, section 5.

Planned Fleet capital expenditures and additions for fiscal 2020 and fiscal 2021 are less than fiscal 2017 to fiscal 2019 amounts, which reflects BC Hydro's plan to keep some fleet assets in-service for longer periods. BC Hydro believes these investment levels are reasonable based on the age and condition of the fleet assets, expected requirements and mitigation plans.

6.8 Business Support and Other Technology Capital Expenditures and Additions

Business Support and Other Technology includes capital expenditures and additions related to Land Purchases, Materials Management upgrades, Field Operations tools and equipment, Control Centre system upgrades, and workforce training equipment. The individual plans for these different areas with the exception of land purchases are generally less than $5 million per year.

Business Support and Other Technology Capital actual and plan expenditures for fiscal 2017 to fiscal 2021 are provided in Table 6-65 below.[316] More information can be found in Appendix I, page 10, lines 8 to 14 and Appendix J, page 93.

Table 6-65 Business Support and Other Technology Actual and Plan Capital Expenditures Fiscal 2017 to Fiscal 2020

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Business Support - Other	170.8	32.0	17.7	28.6	10.0	37.2	37.4	47.3
Other Technology	2.5	1.5	1.0	0.8	2.6	1.1	2.1	0.5

Fiscal 2020 to fiscal 2021 capital expenditures and additions for Business Support include upgrades to the oil management operating infrastructure, constructing an energized training substation, and equipment for commissioning new power system assets.

Business Support and Other Technology actual and plan capital additions fiscal 2017 to fiscal 2021 are provided in Table 6-66 below.[317]

Table 6-66 Business Support and Other Technology Actual and Plan Capital Additions Fiscal 2017 to Fiscal 2020

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Business Support - Other	170.0	47.3	22.1	29.5	15.5	39.6	38.7	43.5
Other Technology	2.5	4.6	1.0	26.0	2.6	0.4	6.6	0.5

6.9 Site C Project

Site C Project actual and planned capital expenditures for fiscal 2015 to fiscal 2021 are provided in Table 6-67 below. More information can be found in Appendix I, page 10, line 15 and Appendix J, page 129.

Table 6-67 Site C Project Actual and Plan Capital Expenditures Fiscal 2015 to Fiscal 2021

Site C CapEx - Table 6-67	Previous	F2015	F2016	F2017	F2018	F2019	F2020	F2021
$ Million	Years	Actual	Actual	Actual	Actual	Forecast	Plan	Plan
Deferred Capital	337.9	80.7	17.0	17.7	18.7	19.5	16.8	17.8
Construction Capital		25.2	489.4	662.7	704.8	1,186.8	1,530.0	1,535.5
Total	337.9	105.9	506.4	680.9	723.5	1,206.3	1,546.8	1,553.3

Table 6-68 Site C Project Actual and Plan Capital Additions Fiscal 2015 to Fiscal 2021

Site C CapAdd - Table 6-68	Previous	F2015	F2016	F2017	F2018	F2019	F2020	F2021
$ Million	Years	Actual	Actual	Actual	Actual	Forecast	Plan	Plan
Deferred Capital	-							
Construction Capital	-						27.9	189.4
Total	-	-	-	-	-	-	27.9	189.4

[317] Fiscal 2017 and fiscal 2018 variances greater than $10 million are described in Appendix G, section 5.

The Site C Project will construct a third dam and hydroelectric generating station on the Peace River in northeast B.C. to provide 1,100 megawatts of capacity, and produce about 5,100 gigawatt hours of electricity per year. In December 2014, the Project received approval from the Provincial Government to proceed to construction. On November 1, 2017, the BCUC issued their final report on the Site C Project. This led to a decision from the Provincial Government on December 11, 2017 announcing their approval to proceed with the Site C Project. As part of this announcement, BC Hydro provided a revised cost estimate of $10.7 billion, consisting of a BC Hydro project budget of $9.992 billion and a project reserve of $0.708 billion subject to Treasury Board control. Construction of the Site C Project started in summer 2015, with completion expected in fiscal 2025.

In fiscal 2020 and fiscal 2021 there are planned capital additions of $217 million for transmission related assets. These assets will enhance and increase reliability of BC Hydro’s transmission infrastructure in the area. The effect of those additions on the test period revenue requirements is small, since the assets are being amortized over a 15 to 65 year period, depending on the asset class.

The majority of the planned capital additions for the Site C Project are forecast to enter service in fiscal 2024, at which point they will begin to be recovered in rates.

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Chapter 7

Regulatory Accounts

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7.1 Introduction

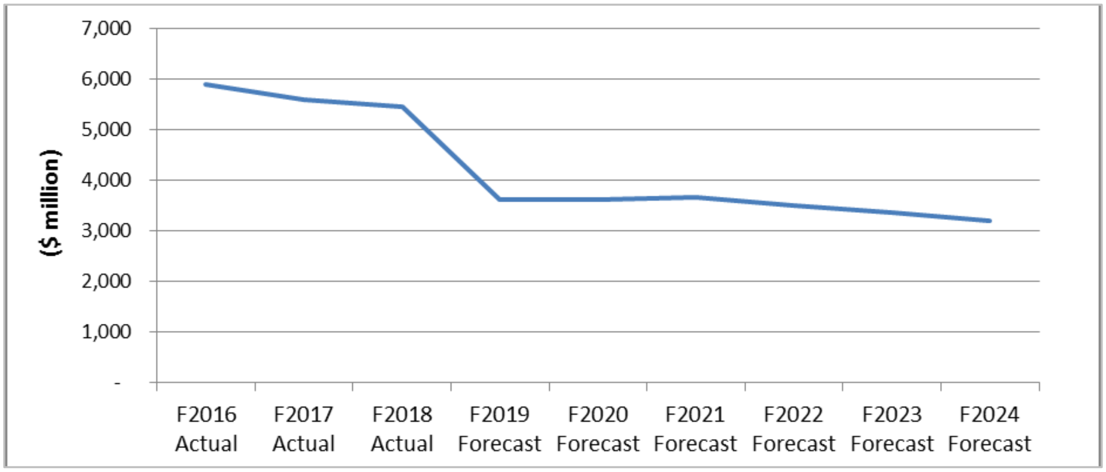
This chapter describes BC Hydro's deferral and regulatory accounts (collectively referred to as regulatory accounts) and our plan to manage them, including our proposals to change or close those accounts. BC Hydro is not requesting approval of any new regulatory accounts in this application.

The general purpose of a regulatory account is to defer costs or revenues for future recovery or refund. In the absence of rate-regulated accounting, these costs or revenues would be recognized in the current accounting period. Regulatory accounts can either be regulatory assets (amounts to be recovered from ratepayers) or regulatory liabilities (amounts to be refunded to ratepayers). Regulatory accounts are not debt, though BC Hydro has often incurred debt to fund the expenditures in regulatory accounts that have not yet been recovered from ratepayers.

BC Hydro's use of regulatory accounts is in accordance with International Financial Reporting Standards (**IFRS**) and in compliance with BCUC Orders and government directions. Rate-regulated accounting is permitted under IFRS 14, *Regulatory Deferral Accounts*.

As shown in Figure 7-1 below, BC Hydro has had three successive years of declining regulatory account balances.

Figure 7-1 Regulatory Account Balances Fiscal 2016 to Fiscal 2018 Actual and Fiscal 2019 to Fiscal 2024 Forecast

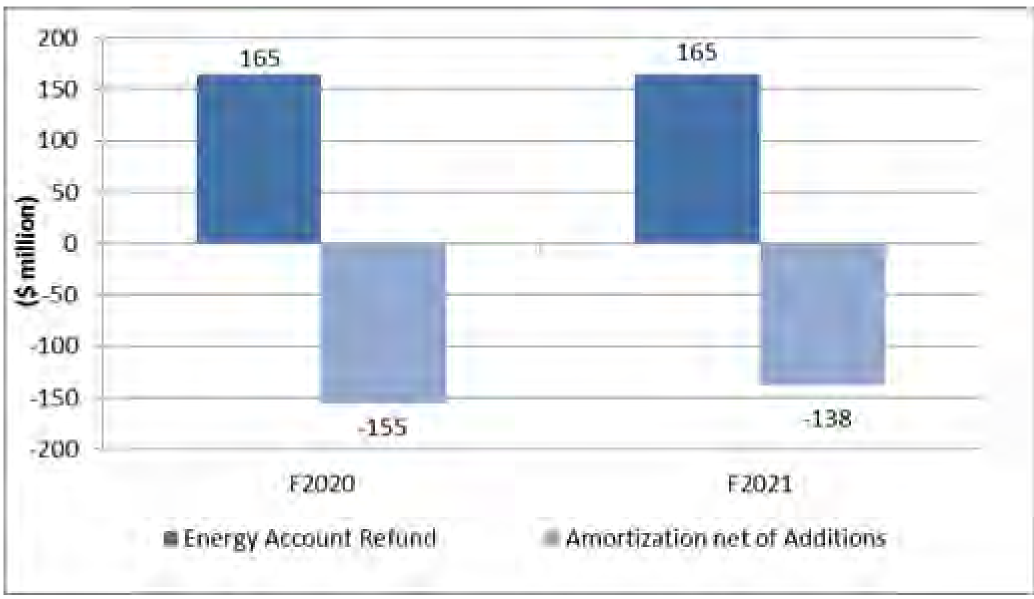


As shown in Figure 7-1 above, BC Hydro's total net regulatory account balance peaked at $5.9 billion in fiscal 2016 and is forecast to be reduced to $3.6 billion at the end of fiscal 2019 (a reduction of $2.3 billion or 39 per cent) and to $3.2 billion at the end of fiscal 2024. In addition, BC Hydro has or has proposed regulatory mechanisms to recover the balances of all but three of its regulatory accounts in rates, within the rate increases proposed for the test period. As discussed in section 7.5.6, the Mining Customer Payment Plan Regulatory Account, the Customer Crisis Fund Regulatory Account and the Site C Regulatory Account do not have approved recovery mechanisms, as recovery mechanisms are not yet required for those accounts.

A key driver of the reduction to the total net regulatory account balance in fiscal 2019 stems from the Comprehensive Review, which resulted in the write-off of the balance of the Rate Smoothing Regulatory Account. Other factors contributing to the reduction include the ongoing recovery of regulatory account balances in rates based on existing recovery mechanisms, reductions to the Trade Income Deferral Account due to higher than planned Powerex net income, and the one-time accounting credit adjustment of $319 million to the Heritage Deferral Account as a result of the adoption of a new IFRS revenue standard in fiscal 2019.[318]

As shown in Figure 7-2 below, over the test period, the balance in BC Hydro's regulatory accounts will continue to be reduced through the ongoing recovery of regulatory account balances in rates based on existing recovery mechanisms (net of additions). The reduction is offset by the proposed refund of the forecast balance in the Cost of Energy Variance Accounts, as discussed in section 7.7.1. As a result, as shown in Figure 7-2 below, there is only a slight overall change in the net regulatory account balance over the test period.

Figure 7-2 Regulatory Account Amortization (Net of Additions), Fiscal 2020 and Fiscal 2021



Almost all of the forecast balance in fiscal 2024 resides in five regulatory accounts that are being recovered (or will be recovered) in rates over a longer period of time as the nature of these accounts are longer term. Further information is provided in section 7.3 below.

[318] Refer to Chapter 7, section 7.7.1 and Chapter 8, section 8.13.2 for further information on this adjustment.

BC Hydro currently has 29 regulatory accounts. In this application, BC Hydro is requesting approval to close two regulatory accounts, which would reduce the total number of regulatory accounts to 27 by the end of fiscal 2021. In addition, BC Hydro will be seeking approval to close the Rock Bay Remediation Regulatory Account in its next revenue requirements application as remediation of the Rock Bay property is complete and the balance in that account will be fully recovered by the end of the subsequent test period.

This chapter is organized around the following key points:

- Section 7.2 explains that the Comprehensive Review has responded to concerns raised by the Auditor General by enhancing the BCUC's oversight of BC Hydro.
- Section 7.3 presents our approach to managing regulatory account balances over the next five years. It shows the actual and forecast closing account balances of the regulatory accounts by year from fiscal 2017 to fiscal 2024. Based on the requests in this application, the total balance in the regulatory accounts is expected to decline by approximately $2.3 billion from fiscal 2018 to fiscal 2024;
- Section 7.4 explains that BC Hydro's use of regulatory accounts is in accordance with IFRS;
- Section 7.5 explains that the types of regulatory accounts used by BC Hydro are consistent with those in the BCUC Regulatory Account Filing Checklist,[319] and outlines considerations to set appropriate mechanisms to ensure the balances in our regulatory accounts are recovered over the appropriate time period;

[319] https://www.bcuc.com/Documents/Guidelines/2017/05-03-2017_RegulatoryAccountFilingChecklist.pdf.

- Section 7.6 outlines criteria for evaluating the establishment of new regulatory accounts;
- Section 7.7 describes the existing regulatory accounts where BC Hydro is requesting changes, outlines the reasons for each request, and provides a description of each regulatory account for context. BC Hydro's requests in this application are summarized in section 7.1.1 below;
- Section 7.8 explains that BC Hydro is not requesting changes to most of its existing regulatory accounts, and provides a description of each unchanged regulatory account for context;
- Section 7.9 explains that BC Hydro applies interest to several regulatory accounts at BC Hydro's weighted average cost of debt in recognition of the carrying costs incurred by BC Hydro; and
- Section 7.10 provides a high-level summary of the information in this chapter for each of BC Hydro's regulatory accounts.

Additional information on the regulatory accounts is also provided in Schedules 2.1 and 2.2 of Appendix A.

7.1.1 BC Hydro Requests Approval of Seven Changes to Existing Regulatory Accounts and to Close Two Existing Accounts

BC Hydro is requesting approval of seven changes related to existing regulatory accounts and to close two existing regulatory accounts. BC Hydro is not requesting approval of any new regulatory accounts in this application.

Specifically, BC Hydro requests BCUC approval to:

- Reduce the Deferral Account Rate Rider (**DARR**) from 5 per cent to 0 per cent on April 1, 2019;
- Refund the forecast fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy

Variance Accounts, over the fiscal 2020 to fiscal 2021 test period. This would result in a net credit to the benefit of ratepayers of $329.1 million being amortized into rates during the test period;

- Defer any variances related to the accounting for EPAs determined to be leases under IFRS 16, which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account;
- Defer any variances between forecast and actual amounts related to the Biomass Energy Program which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account. This will ensure that BC Hydro recovers its costs with respect to the Biomass Energy Program;[320]
- Continue to defer, on an annual and ongoing basis, any variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account, continue to apply interest to the balance of the account and recover the forecast interest charged to the account each year, and continue to recover the forecast account balance at the end of a test period over the next test period;
- Defer low-carbon electrification expenditures to the DSM Regulatory Account, consistent with the Direction to the BCUC Respecting Undertaking Costs;
- Remove the reference to the “Prescribed Standards” from the scope of what may be deferred to the Site C Regulatory Account, as BC Hydro has fully adopted IFRS. This will allow BC Hydro to continue to defer to the Site C Regulatory Account any costs related to the Site C Project that are not able to be capitalized;
- Close the Capital Project Investigation Costs Regulatory Account at the end of fiscal 2021 as its balance will be fully amortized into rates at that time; and

[320] The Government of B.C. has indicated that it intends to provide a direction to the BCUC with respect to the approval of the program documentation and to require the costs associated with the program to be recovered from ratepayers.

- Close the Rate Smoothing Regulatory Account in fiscal 2020 as this account has a zero balance and BC Hydro is not proposing to smooth rates over the fiscal 2020 to fiscal 2021 test period.

7.2 BCUC Oversight Has Been Enhanced

The Comprehensive Review has responded to concerns raised by the Auditor General by enhancing the BCUC's oversight of BC Hydro. Actions taken include repealing a regulation such that BC Hydro will fully adopt IFRS and writing off the balance in the Rate Smoothing Regulatory Account.

7.2.1 Comprehensive Review Makes Significant Efforts to Address Auditor General's Concerns

BC Hydro recognizes the concerns raised by the Auditor General regarding BC Hydro's regulatory accounts. In a report on Rate-Regulated Accounting at BC Hydro, dated February 2019, the Auditor General also expressed concerns with regard to the number of directions issued by the Government of B.C. to the BCUC, which have impacted BC Hydro's regulatory accounts.

BC Hydro and the Government of B.C. have made significant efforts in the Comprehensive Review to address the concerns raised by the Auditor General. Specifically:

- **BCUC oversight has been enhanced:** On February 14, 2019, the Government of B.C. issued its report on Phase One of the Comprehensive Review. The report highlights changes made by the Government of B.C. which have enhanced the BCUC's oversight of BC Hydro. Specifically, the Government of B.C. repealed Directions No. 3, 6, and 7, providing the BCUC with enhanced oversight over BC Hydro's regulatory accounts. The Government of B.C. issued Direction No. 8 to the BCUC which continues to provide direction to the BCUC in certain areas previously covered by Direction No. 7. Further information is provided in Chapter 2, section 2.2.1.

- **BC Hydro has fully adopted IFRS:** In November 2018, the Government of B.C. repealed Part 3 of the Government Organization Accounting Standards Regulation 257/2010. BC Hydro has subsequently fully adopted IFRS, effective for its fiscal year ending March 31, 2019. This is the appropriate basis of accounting for BC Hydro under Canadian generally accepted accounting principles (**CGAAP**) and addressed the one recommendation from the Auditor General's review of rate-regulated accounting at BC Hydro.
- **Rate Smoothing Regulatory Account has been written-off:** As part of the Comprehensive Review, BC Hydro ceased using the Rate Smoothing Regulatory Account at the end of the third quarter of fiscal 2019. The balance of the Rate Smoothing Regulatory Account was written-off in December 2018 in the amount of $1.044 billion, resulting in a reduction to BC Hydro's retained earnings and a forecast net loss for BC Hydro in fiscal 2019. This means that the cost of the write-off is borne by the Government of B.C. as BC Hydro's shareholder, and not by ratepayers. This write-off is a significant driver of the forecast decrease in the net regulatory account balance in fiscal 2019.

7.3 Plan to Manage Regulatory Account Balances

This section outlines our plan to manage our regulatory account balances. At the end of fiscal 2018, BC Hydro had a total of 29 regulatory accounts, with a total net balance of $5.5 billion. Based on existing approved recovery mechanisms and those proposed in this application, BC Hydro is forecasting that the total net balance in the accounts will be reduced to $3.7 billion at the end of fiscal 2021 and to $3.2 billion by the end of fiscal 2024. Almost all of the remaining forecast balance in fiscal 2024 is in five accounts, which are long-term by nature.

A key driver of this reduction is the write-off of the balance in the Rate Smoothing Regulatory Account. Other factors contributing to the reduction in BC Hydro's net regulatory account balance include the ongoing recovery of regulatory account balances in rates based on existing recovery mechanisms, reductions to the Trade

Income Deferral Account due to higher than planned Powerex net income, as well as a one-time accounting credit adjustment of $0.3 billion to the Heritage Deferral Account as a result of the adoption of a new IFRS revenue standard in fiscal 2019. This adjustment is discussed further in section 7.7.1 below and in Chapter 8, section 8.13.2.

BC Hydro's actual and forecast regulatory account balances for the fiscal 2017 to fiscal 2021 period are presented in Table 7-1 below.

Table 7-1 Summary of Regulatory Account Balances, Fiscal 2017 to Fiscal 2018 Actual and Fiscal 2019 to Fiscal 2021 Forecast

	($ million)	F2017 Actual	F2018 Actual	F2019 Forecast	F2020 Forecast	F2021 Forecast
		1	2	3	4	5
1	Opening Balance	5,908	5,597	5,454	3,622	3,632
2	Additions	(17)	34	(39)	165	159
3	Interest	75	62	39	24	28
4	Recoveries / Other	(370)	(238)	(1,832)	(180)	(160)
5	Net Change	(311)	(143)	(1,832)	9	26
6	**Closing Balance**	**5,597**	**5,454**	**3,622**	**3,632**	**3,658**

Table 7-2 below presents the fiscal 2017 and fiscal 2018 actual and fiscal 2019 to fiscal 2024 forecast balances of BC Hydro's regulatory accounts. The table shows that as a result of our plan the forecast balances will continue to decline to fiscal 2024.

Table 7-2 Regulatory Account Balances Fiscal 2017 to Fiscal 2018 Actual and Fiscal 2019 to Fiscal 2024 Forecast

	($ million)	Schedule Reference	F2017 Actual	F2018 Actual	F2019 Forecast	F2020 Forecast	F2021 Forecast	F2022 Forecast	F2023 Forecast	F2024 Forecast
			1	2	3	4	5	6	7	8
	Cost of Energy Variance Accounts									
1	Heritage Deferral Account	2.1 L20	(53)	(104)	(388)	(198)	0	(0)	(0)	(0)
2	Non-Heritage Deferral Account	2.1 L21	756	463	120	52	(0)	(16)	(22)	(24)
3	Trade Income Deferral Account	2.1 L22	194	127	(24)	(12)	(0)	0	0	0
	Total	2.1 L23	897	487	(293)	(158)	(0)	(16)	(22)	(24)
	Other Cash Variance Accounts									
4	Storm Restoration Costs	2.2 L180	39	46	38	19	0	0	0	0
5	Amortization of Capital Additions	2.2 L183	(9)	(5)	20	10	0	0	0	0
6	Total Finance Charges	2.2 L184	(215)	(139)	(9)	(4)	0	0	0	0
7	Rock Bay Remediation	2.2 L190	(23)	(20)	(21)	(10)	(0)	(0)	(0)	(0)
8	Arrow Water Systems	2.2 L193	0	0	0	0	0	0	0	0
9	Remediation	2.2 L195	(16)	(29)	(25)	(13)	0	0	0	0
10	Real Property Sales	2.2 L197	28	38	44	38	31	24	16	9
11	Dismantling Cost	2.2 L200	0	35	51	25	0	0	0	0
12	Customer Crisis Fund	2.2 L202	0	0	0	0	(0)	(1)	(1)	(1)
13	Mining Customer Payment Plan		0	0	0	0	0	0	0	0
	Total		(196)	(73)	99	65	31	23	16	8
	Non-Cash Variance Accounts									
14	Foreign Exchange Gains/Losses	2.2 L178	(66)	(31)	7	5	5	5	5	4
15	Non-Current Pension Costs	2.2 L187	511	303	(3)	(19)	(35)	(51)	(67)	(83)
16	PEB Current Pension Costs	2.2 L201	0	3	(2)	(1)	0	0	0	0
17	Debt Management	2.2 L199	(187)	(158)	(260)	(248)	(235)	(208)	(181)	(154)
	Total		258	118	(258)	(263)	(265)	(254)	(243)	(232)
	Benefit Matching Accounts									
18	DSM	2.2 L173	916	902	927	932	950	932	902	871
19	First Nations Costs	2.2 L174	124	104	85	72	56	38	25	14
20	Site C	2.2 L176	453	472	491	509	526	541	553	556
21	Future Removal and Site Restoration (closed)	2.2 L177	3	(0)	0	0	0	0	0	0
22	Pre-1996 Contributions in Aid of Construction	2.2 L179	91	88	83	78	73	68	63	58
23	Capital Project Investigation Costs	2.2 L181	20	15	10	5	0	0	0	0
24	SMI	2.2 L185	261	239	217	195	174	152	130	109
	Total		1,868	1,821	1,814	1,791	1,778	1,731	1,673	1,607
	Non-Cash Provisions									
25	First Nations Provisions	2.2 L175	409	414	420	423	428	432	431	428
26	Environmental Provisions	2.2 L189	333	310	276	234	194	170	147	129
27	Arrow Water Systems Provision	2.2 L194	4	3	3	3	2	2	2	2
	Total		746	727	699	659	624	604	580	558
	Rate Smoothing Accounts									
28	Rate Smoothing	2.2 L196	489	815	0	0	0	0	0	0
	Total		489	815	0	0	0	0	0	0
	IFRS Transition Accounts									
29	IFRS Property, Plant and Equipment	2.2 L191	962	1,025	1,064	1,079	1,071	1,039	1,007	976
30	IFRS Pension	2.2 L192	574	535	497	459	421	382	344	306
	Total		1,535	1,561	1,561	1,538	1,491	1,421	1,352	1,282
	Total	2.1 L23+2.2 L203	**5,597**	**5,454**	**3,622**	**3,632**	**3,658**	**3,510**	**3,355**	**3,199**

BC Hydro currently has a total of 29 regulatory accounts. Table 7-2 provides a list of 30 regulatory accounts, including the Future Removal and Site Restoration Costs Regulatory Account, which is now closed. The Future Removal and Site Restoration

Regulatory Account is included in Table 7-2 as there was a balance in the account in fiscal 2017. In this application, BC Hydro is requesting approval to close two regulatory accounts, which would reduce the total number of regulatory accounts to 27 by the end of fiscal 2021. In addition, BC Hydro will be seeking approval to close the Rock Bay Remediation Regulatory Account in its next revenue requirements application as remediation of the Rock Bay property is complete and the balance in that account will be fully recovered by the end of the subsequent test period.

Almost all of the forecast balances in fiscal 2024 under our plan reside in five regulatory accounts that are being recovered (or will be recovered) over a longer period of time as the nature of these accounts are longer-term:

- The First Nations Provisions Regulatory Account, which is drawn down as annual settlement payments are made over a longer period of time;
- The DSM Regulatory Account for which the expenditures added each year are recovered over the 15-year benefit period for customers;
- The Site C Regulatory Account, which is not yet being recovered in rates as the project is not in-service. In a future application, BC Hydro will propose that the balance in the account be recovered over the average life of the assets once the project is in-service, as that is the period that customers will benefit from those costs; and
- The two IFRS Transition Accounts, which are being amortized into rates over 20 years for the IFRS Pension Regulatory Account and 40 years for the IFRS Property, Plant and Equipment Regulatory Account so that the balances in those accounts are recovered over the same period of time as under the previous CGAAP accounting rules. This means that ratepayers are not subject to higher rates as a result of changes in accounting rules.

The balances shown in Table 7-1 and Table 7-2 for fiscal 2019 onward are forecasts based on current information and assumptions at the time the forecast was prepared and reflect our proposed requests in this application. Actual balances will be different than presented for the following reasons:

- First, the forecast indicates that the balance in the three Cost of Energy Variance Accounts will be reduced to zero by the end of fiscal 2021. These accounts capture the variances between forecast and actual energy costs, forecast and actual revenues from energy sales, and forecast and actual trade income in each fiscal year, which can be positive or negative. Forecasting energy costs, revenues from energy sales and trade income is challenging, due to variables beyond BC Hydro's control, such as weather. Therefore, actual additions will differ from the forecast amounts;
- Second, the Non-Current Pension Costs Regulatory Account captures actuarial gains and losses. Annual actuarial gains and losses are sensitive to changes in market discount rates, rates of return on pension plan assets and significant changes in key actuarial assumptions. This means that annual actuarial gains and losses are subject to large positive and negative fluctuations and therefore actuarial gains or losses at the end of each year are difficult to forecast;
- Third, the forecast DSM Regulatory Account balances are based on the activities and expenditures in the current DSM Plan, which is discussed further in Chapter 10. Forecast balances beyond the test period for the DSM Regulatory Account may differ depending on modifications to the DSM Plan in future test periods; and
- Fourth, BC Hydro has several cash and non-cash variance accounts that capture variances between forecast and actual costs. BC Hydro expects the balances in these accounts will be different than the amounts forecast in this application due to non-controllable factors such as interest rates and weather.

Table 7-3 below sets out the baseline forecast amounts. The variances deferred to BC Hydro's regulatory accounts will be determined from these baseline forecasts.

Table 7-3 Fiscal 2020 to Fiscal 2021 Baseline Forecast Amounts for Regulatory Accounts

	($ million)	Schedule Reference	F2020 Plan	F2021 Plan
			1	2
	Heritage Deferral Account			
1	COE Subject to Deferral to HDA	4.0 L66	327.7	294.2
	Non-Heritage Deferral Account			
2	COE Subject to Deferral to NHDA	4.0 L80	1,571.0	1,637.2
3	Total Rate Revenue	1.0 L23	5,256.5	5,288.3
4	External OATT	15.0 L4	15.4	15.4
5	NTL Supplemental Charge Revenue	15.0 L9	2.3	2.3
	Trade Income Deferral Account			
6	Trade Income	1.0 L17	120.6	120.6
	Other Regulatory Accounts			
7	Non-Current PEB - Pension	8.0 L17	(33.2)	(36.7)
8	Current PEB - Operating Cost	N/A	62.1	63.4
9	Storm Restoration Costs	N/A	17.8	17.8
10	Total Finance Charges	8.0 L32-L16-L17	729.5	697.8
11	Amortization of Capital Additions	13.0 L35	28.6	80.7
12	Net Gain on Property Sales	5.0 L76	10.0	10.0
13	Dismantling Cost	5.0 L72:L75	67.0	43.0

7.4 BC Hydro's Use of Regulatory Accounts is in Accordance with Accounting Standards

BC Hydro's use of regulatory accounts is in accordance with IFRS and in compliance with BCUC Orders and government directions. Rate-regulated accounting is permitted under IFRS 14, Regulatory Deferral Accounts. As discussed in Chapter 8, section 8.13, BC Hydro applies rate-regulated accounting in accordance with IFRS 14.

Regulatory accounts are commonly used in the utility industry in North America. Regulatory accounts are used to defer differences between forecast and actual costs or revenues, to better match costs and benefits for customers, to smooth out the rate impact of a large, non-recurring cost, or to smooth out rate increases. As discussed below, BC Hydro uses regulatory accounts for these purposes.

7.5 Types of Regulatory Accounts and Amortization Periods

The five types of regulatory accounts used by BC Hydro are consistent with the BCUC Regulatory Account Filing Checklist.[321] The five types of accounts are described below, including a discussion of the relevant considerations when determining the appropriate recovery mechanisms to ensure that the balances in the accounts are recovered over the appropriate time period.

7.5.1 Variance Accounts

Regulatory accounts may be used to capture variances between forecast costs or revenues and actual costs or revenues. For BC Hydro, this includes variances between forecast and actual costs due to non-controllable factors such as water inflow levels, interest rates, discount rates, and market prices of energy, which are difficult to forecast. These types of variances are captured in BC Hydro's cash and non-cash variance accounts, which are discussed below.

BC Hydro believes that it should generally assume financial responsibility for controllable risks and create variance accounts for non-controllable risks. In the Fiscal 2005 to Fiscal 2006 Revenue Requirements Application, BC Hydro proposed the following criteria to assess whether a risk is controllable or non-controllable:[322]

321 https://www.bcuc.com/Documents/Guidelines/2017/05-03-2017_RegulatoryAccountFilingChecklist.pdf. Specifically, when requesting approval for a new regulatory account, the BCUC Regulatory Account Filing Checklist requires that regulated entities classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or (e) other and to identify if the regulatory account is a cash or non-cash account.

322 BC Hydro Fiscal 2005 - Fiscal 2006 Revenue Requirement Application Argument, page 70.

1. BC Hydro's ability to directly or indirectly influence the cost category;
2. The volatility of the cost category;
3. The predictability of the cost category;
4. The materiality of the cost category to the revenue requirement; and
5. The frequency of major exceptions within the cost category.

In its Decision on the Fiscal 2005 to Fiscal 2006 Revenue Requirements Application, the BCUC accepted BC Hydro's proposed criteria but concluded that risk/reward considerations were also a relevant consideration.[323]

BC Hydro is not proposing any changes in this application to the criteria used to assess whether a risk is controllable or non-controllable.

BC Hydro's Cost of Energy Variance Accounts (the Heritage Deferral Account, the Non-Heritage Deferral Account and Trade Income Deferral Account) are examples of variance accounts that defer, for recovery or refund in a future period, differences between forecast and actual costs or revenues. The balances in these accounts are currently recovered through the DARR, which is discussed further in section 7.5.6.

BC Hydro also has cash variance accounts that capture the difference between forecast and actual costs for non-energy related costs that BC Hydro considers to be non-controllable. Examples include the Storm Restoration Costs and the Total Finance Charges regulatory accounts. Amounts transferred to cash variance accounts in a test period are generally recovered over the next test period. This approach is appropriate as these accounts represent costs that provide immediate, rather than long-term benefits.

Lastly, BC Hydro has non-cash variance accounts that capture the differences between forecast and actual non-controllable costs, which are non-cash in nature,

323 BC Hydro Fiscal 2005 to Fiscal 2006 Revenue Requirement Application Decision, pages 29 to 30.

for recovery from or refund to ratepayers in a future period. BC Hydro currently has four non-cash variance accounts: the Foreign Exchange Gains and Losses, the Non-Current Pension Costs, the PEB Current Pension Costs, and the Debt Management regulatory accounts. The recovery period for these variance accounts match the underlying attribute. For example, the Foreign Exchange Gains and Losses Regulatory Account is amortized on a straight-line pool basis over the weighted average life of the related debt and the Non-Current Pension Costs Regulatory Account is amortized over the average remaining service life of employees.

7.5.2 Benefit Matching Accounts

Regulatory accounts are often used to reflect timing differences between when a utility spends money to provide a service or acquire an asset, and when that expenditure provides benefits to ratepayers. The benefit of a particular service or asset may accrue to ratepayers over a long period of time. Regulatory accounts can be used to match the benefit with the cost, thereby supporting intergenerational equity between current and future ratepayers. The amortization period for this type of account will vary depending on the period of time that the benefit of a particular service or asset accrues to ratepayers. The use of this type of regulatory account means that BC Hydro's current customers are not required to pay for the full cost of an asset or service that will provide benefits to customers in the future.

The DSM Regulatory Account is an example of this type of account. Through DSM measures, BC Hydro spends money in current years to reduce the amount of electricity that customers would otherwise use in current and future periods. This results in lower energy costs and delayed or reduced infrastructure costs. The benefits of reduced costs from these DSM measures accrue to future customers. Therefore, the costs of DSM measures are matched to the benefits realized by future customers. DSM costs are deferred and amortized over 15 years, which reflects the average measure life of DSM measures. Further information is provided in Chapter 10, section 10.5.6.

The Site C Regulatory Account is another example of this type of regulatory account. This account defers project investigation costs related to the Site C Project to future years. The Site C Project has a long development period before it will be placed into service and provide benefits to customers. If these project investigation costs had been expensed as incurred, it would have created unfair rate impacts on current ratepayers, prior to the benefits of the project being provided.

7.5.3 Non-Cash Provisions

Non-cash provisions are regulatory accounts set up in response to loss provision liabilities required under IFRS. These provisions are not recovered in rates until actual cash expenditures are made against the provision. At that time, the provision is drawn down by the amount of the expenditure and a corresponding amount is transferred to the matching regulatory account. This amount is then amortized into rates based on the approved amortization method. The provision regulatory accounts remain in place until the loss provision liability is no longer required under IFRS. These accounts are regulatory assets which, subject to BCUC approval, preserve BC Hydro’s ability to collect, in rates, any actual amounts paid in respect of these provisions. BC Hydro currently has three non-cash provision regulatory accounts: the First Nations Provisions, the Environmental Provisions, and the Arrow Water Systems Provision regulatory accounts.

7.5.4 Rate Smoothing Accounts

Concerns about rate impacts can lead to the establishment of a regulatory account to smooth required rate increases over a period of time or to smooth the rate impact of a large, one-time expenditure. The recovery period for this type of account would be determined by the amount and nature of the expenditure, as well as other rate increase pressures that may exist at the time.

Pursuant to Direction No. 7,the BCUC had approved for use, starting in fiscal 2015, a Rate Smoothing Regulatory Account to defer portions of BC Hydro's allowed revenue requirement for recovery in rates in future fiscal years. As part of the Comprehensive Review, BC Hydro ceased using the Rate Smoothing Regulatory Account at the end of the third quarter of fiscal 2019. The balance of the Rate Smoothing Regulatory Account was written-off in December 2018 in the amount of $1.044 billion, resulting in a reduction to BC Hydro's retained earnings and a forecast net loss for BC Hydro in fiscal 2019. This means that the cost of the write-off is borne by the Government of B.C. as BC Hydro's shareholder, and not by ratepayers. As a result, there is a zero balance in the Rate Smoothing Regulatory Account at the beginning of the test period. BC Hydro is not proposing to smooth rates over the fiscal 2020 to fiscal 2021 test period and is requesting BCUC approval to close the existing Rate Smoothing Regulatory Account.

7.5.5 IFRS Transition Accounts

A change in the accounting standards applicable to BC Hydro may create non-controllable financial impacts, requiring a regulatory account to protect customers from sudden and significant rate increases.

In fiscal 2013, BC Hydro transitioned to the Prescribed Standards directed by the Government of B.C.'s Treasury Board. The Prescribed Standards were based on the principles of IFRS, combined with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980, *Regulated Operations* with one modification. This change impacted the method of accounting for capital overheads. It also required BC Hydro to recognize, on its balance sheet, all unamortized actuarial gains and losses on its pension and other post-employment benefit plans. To recover the financial impact of these changes from customers over a reasonable time period, BC Hydro proposed the establishment of the IFRS Transition regulatory accounts. If BC Hydro had recognized the impact of the transition to IFRS in its rates at the time of the transition, the rate impact for customers in the year of transition, would have been significant.

The recovery periods for the IFRS Transition Accounts are 20 years for the IFRS Pension Regulatory Account and 40 years for the IFRS Property, Plant and Equipment Regulatory Account. These recovery periods mean that the accounts recover the transition costs of pension and capital assets over the same period of time as if the IFRS rules had not come into place as part of the Prescribed Standards.

7.5.6 Summary of Recovery Mechanisms

Table 7-4 below provides a summary of the rationale to determine the appropriate recovery mechanisms for BC Hydro's regulatory accounts.

Table 7-4 Summary of Rationale for Regulatory Account Recovery Mechanisms

Type of Regulatory Account	Rationale for Recovery Mechanism
Variance Accounts:	
Cost of Energy Variance Accounts	The Deferral Account Rate Rider mechanism minimizes intergenerational inequity by being responsive to the changing net balance in the cost of energy variance accounts, while maintaining rate stability for customers to the extent practicable. BC Hydro is proposing to reduce the Deferral Account Rate Rider from 5 per cent to 0 per cent on April 1, 2019 and to refund the forecast fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts over the fiscal 2020 to fiscal 2021 test period.
Other Cash Variance Accounts	To minimize intergenerational inequity, cash variance accounts should be recovered in the subsequent test period.
Non-Cash Variance Accounts	Non-cash variances should be recovered over the remaining period of the associated asset or liability (e.g., estimated average remaining service life of employees or remaining term of debt issuances).
Benefit Matching Accounts	To achieve intergenerational equity, the recovery period should match the future benefit period of the expenditure.
Non-Cash Provisions	Since non-cash provisions are not recovered in rates, no recovery mechanism is required. The provision is drawn down when actual expenditures are charged to the regulatory account.
Rate Smoothing Accounts	Recovery mechanisms can vary based on the purpose of the rate smoothing account. For example, if the purpose of a rate smoothing account is to smooth rates over a specific test period only, the account should be recovered over the related test period. BC Hydro is not proposing to smooth rates over the fiscal 2020 to fiscal 2021 test period.
IFRS Transition Accounts	To smooth the impact of changes in accounting standards, the balances in these accounts should be recovered on the same basis as they would have been recovered under the previous accounting rules.

BC Hydro has BCUC approved recovery mechanisms to collect, in rates, the balances in almost all of its regulatory accounts. The following three regulatory accounts do not have approved recovery mechanisms, as they are not yet required:

1. Mining Customer Payment Plan Regulatory Account – BC Hydro will request a recovery mechanism, if necessary, upon completion of the five year program, which commenced in March 2016. This account currently has a zero balance;
2. Customer Crisis Fund Regulatory Account – BC Hydro will request a recovery mechanism upon completion of the three year pilot program which commenced in May 2018; and
3. Site C Regulatory Account – BC Hydro will request a recovery mechanism for this account in a future application, as the project is not yet in-service.

7.6 Threshold for Establishing New Regulatory Accounts

BC Hydro is not requesting to establish any new regulatory accounts in this application.

However, should a new regulatory account be required in the future, BC Hydro believes that the criteria discussed in section 7.5 continue to be appropriate. With respect to the deferral of differences between forecast and actual costs, BC Hydro continues to believe that it should assume financial responsibility for controllable risks and use regulatory accounts for non-controllable risks. However, to limit the number of regulatory accounts, an objective measure should be used as a threshold for creating a new regulatory account. BC Hydro believes that un-forecast and non-controllable expenditures of greater than $10 million in a fiscal year would be considered material. Therefore, in these cases, a new regulatory account would be warranted to defer the impact for future recovery.

7.7 BC Hydro's Proposed Changes to Regulatory Accounts are Limited

BC Hydro is requesting approval of seven changes related to existing regulatory accounts and to close two existing regulatory accounts. BC Hydro is not requesting approval of any new regulatory accounts in this application.

Specifically, BC Hydro requests BCUC approval to:

- Reduce the DARR from 5 per cent to 0 per cent on April 1, 2019;
- Refund the forecast fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts, over the fiscal 2020 to fiscal 2021 test period. This would result in a net credit to the benefit of ratepayers of $329.1 million being amortized into rates during the test period;
- Defer any variances related to the accounting for EPAs determined to be leases under IFRS 16, which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account;
- Defer any variances between forecast and actual amounts related to the Biomass Energy Program which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account. This will ensure that BC Hydro recovers its costs with respect to the Biomass Energy Program;[324]
- Continue to defer, on an annual and ongoing basis, any variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account, continue to apply interest to the balance of the account and recover the forecast interest charged to the account each year, and continue to recover the forecast account balance at the end of a test period over the next test period;
- Defer low-carbon electrification expenditures to the DSM Regulatory Account, consistent with the Direction to the BCUC Respecting Undertaking Costs;
- Remove the reference to the “Prescribed Standards” from the scope of what may be deferred to the Site C Regulatory Account, as BC Hydro has fully

[324] The Government of B.C. has indicated that it intends to provide a direction to the BCUC with respect to the approval of the program documentation and to require the costs associated with the program to be recovered from ratepayers.

adopted IFRS. This will allow BC Hydro to continue to defer to the Site C Regulatory Account any costs related to the Site C Project that are not able to be capitalized;

- Close the Capital Project Investigation Costs Regulatory Account at the end of fiscal 2021 as its balance will be fully amortized into rates at that time; and
- Close the Rate Smoothing Regulatory Account in fiscal 2020 as this account has a zero balance and BC Hydro is not proposing to smooth rates over the fiscal 2020 to fiscal 2021 test period.

The sections below provide the rationale for each proposed change to the regulatory accounts. To provide context for to these requests, the sections below include a description of the account, the history of the account and the existing or proposed recovery mechanism or period for the recovery of the account balance.

7.7.1 Cost of Energy Variance Accounts

BC Hydro has three Cost of Energy Variance Accounts that capture the differences between forecast and actual revenues and energy costs: the Heritage Deferral Account, the Non-Heritage Deferral Account and the Trade Income Deferral Account.

The Heritage Deferral Account and Trade Income Deferral Account were created pursuant to Heritage Special Direction No. HC2 and BCUC Order No. G-96-04. Special Direction No. HC2 was repealed in March 2014 and the Heritage Deferral Account and the Trade Income Deferral Account were continued on an ongoing basis through Direction No. 7 and BCUC Order No.G-48-14.

By Order No. G-96-04, the BCUC also approved the establishment of the Non-Heritage Deferral Account and approved the specific cost components eligible for deferral to the Heritage Deferral Account and to the Non-Heritage Deferral Account. Through subsequent Orders, the scope of the Non-Heritage Deferral

Account has been expanded.[325] Notably, by Order No. G-16-09, the BCUC authorized BC Hydro to defer to the Non-Heritage Deferral Account, the variances between forecast and actual cost of energy arising from differences in forecast and actual domestic customer load in fiscal 2009 and fiscal 2010. This was continued through the Fiscal 2011 Negotiated Settlement Agreement and by Order No. G-77-12A to the Fiscal 2012 to Fiscal 2014 Revenue Requirements Application. Direction No. 7 required the BCUC to allow these variances to be deferred to the Non-Heritage Deferral Account on an ongoing basis. Direction No. 7 also required the BCUC to allow BC Hydro to defer costs associated with the decommissioning of portions of Burrard Thermal not required for transmission support services, to the Non-Heritage Deferral Account.

The purpose of the three Cost of Energy Variance Accounts is to defer the differences between forecast and actual revenues and energy costs for recovery or refund to ratepayers in future periods. These differences are non-controllable and can be positive or negative. The variances captured by the Cost of Energy Variance Accounts can be summarized as follows:

- The Heritage Deferral Account captures variances between the forecast and actual cost of Heritage Energy, Market Electricity Purchases, Surplus Sales and Domestic Transmission costs related to Surplus Sales as described in Chapter 4, sections 4.2.2 and 4.2.4. In addition, the Heritage Deferral Account captures variances between forecast and actual costs and revenues for items approved by BCUC Order No. G-96-04, which includes Skagit Valley Treaty revenues.

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[325] BCUC Order No. G-16-11 approved the deferral of variances between forecast and actual transmission service revenue and non-capital emergency transmission maintenance expenditures over $1 million to the Non-Heritage Deferral Account.
BCUC Order No. G-68-17 approved the deferral of variances between forecast and actual Northwest Transmission Line Supplemental Charge revenues to the Non-Heritage Deferral Account.
BCUC Order No. G-130-18 approved the deferral of the fiscal 2019 Lease revenues arising from the Waneta 2017 Transaction and the revenue associated with capital expenditures made by Teck with respect to Teck's two-third interest in Waneta during the Lease Term to the Non-Heritage Deferral Account. The Order also approved that the variance between forecast and actual water rentals in a given year arising from the Waneta 2017 transaction be excluded from the water rental variances that are currently deferred to the Non-Heritage Deferral Account during the Lease Term.

- The Non-Heritage Deferral Account captures variances between the forecast and actual cost of Non-Heritage Energy which includes IPPs and Long-Term Commitments, and Net Purchases (Sales) from Powerex as described in Chapter 4, sections 4.2.3 and 4.2.4. In addition, the Non-Heritage Deferral Account captures variances between forecast and actual costs and revenues for items approved by BCUC Order No G-96-04, variances between forecast and actual domestic customer load (referred to as the Domestic Revenue Variance), and subsequent Orders as noted above.
- The Trade Income Deferral Account captures variances between the forecast and actual Trade Income as described in Chapter 8, section 8.9.

7.7.1.1 Recovery Mechanism

BC Hydro believes that it continues to be appropriate to defer cost and revenue variances to the Cost of Energy Variance Accounts, consistent with past practice and existing orders. These variances are non-controllable and the deferral of variances ensures that BC Hydro's customers pay the actual costs.

The fiscal 2019 forecast closing balance in the Cost of Energy Variance Accounts is a net credit balance (i.e., amount owing to ratepayers) of $293 million, in part due to a one-time accounting adjustment of $319 million as a result of the adoption of a new IFRS revenue standard in fiscal 2019. The application of IFRS 15, *Revenue from Contracts with Customers*, impacted the recognition of revenues under the Skagit River Agreement, resulting in a retroactive decrease in unearned revenues and a corresponding adjustment to the Heritage Deferral Account to the benefit of ratepayers.[326] Further information is provided in Chapter 8, section 8.13.2.

BC Hydro recovers the balances in the Cost of Energy Variance Accounts using the DARR. Direction No. 7 set the DARR for fiscal 2015 and future fiscal years at

[326] BCUC Order No. G-96-04 approved the deferral of variances between forecast and actual Skagit Valley Treaty revenues to the Heritage Deferral Account. Accordingly, the adjustment was deferred to the Heritage Deferral Account, to the benefit of ratepayers.

5 per cent. However, because Direction No. 7 was repealed and because BC Hydro is forecasting a net credit balance in the accounts for fiscal 2019, BC Hydro is proposing to amortize this balance over the test period. BC Hydro believes that it is appropriate to refund this net credit balance to ratepayers over the fiscal 2020 to fiscal 2021 test period. This would allow ratepayers to realize the benefit of this net credit balance more immediately than if the credit were to be refunded to ratepayers through the DARR.

As these are variance accounts, BC Hydro would not normally forecast additions to the Cost of Energy Variance Accounts. However, over the test period, BC Hydro is forecasting additions to the Non-Heritage Deferral Account for a one-time credit of $18.0 million in fiscal 2020 arising from a transition adjustment related to the adoption of a new IFRS 16, *Leases* standard as described in Chapter 8, section 8.13.3. In addition, BC Hydro is forecasting additions of $3.1 million in fiscal 2020 and $3.5 million in fiscal 2021 related to revenue that BC Hydro is required to recognize for capital expenditures made by Teck with respect to Teck's 2/3 interest in Waneta over the lease period.[327]

Therefore, in this application, BC Hydro is requesting BCUC approval to:

- Reduce the Deferral Account Rate Rider from 5 per cent to 0 per cent on April 1, 2019; and
- Refund the forecast fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts, over the fiscal 2020 to fiscal 2021 test period.

This would result in a net credit to the benefit of ratepayers of $329.1 million being amortized into rates during the test period.

[327] BCUC Order No. G-130-18 approved the deferral of the revenue associated with capital expenditures made by Teck with respect to Teck's two-third interest in Waneta during the Lease Term to the Non-Heritage Deferral Account.

Based on BC Hydro's proposed approach, the forecast balance in each of the Cost of Energy Variance Accounts will be zero at the end of fiscal 2021.

BC Hydro expects to propose to return to the DARR table mechanism approved by the BCUC in the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application in the subsequent test period starting in fiscal 2022.

7.7.1.2 IFRS 16, Leases (Energy Purchase Agreements)

As discussed in Chapter 8, section 8.13.3 of the application, BC Hydro will adopt a new IFRS 16, *Leases* standard, which will become effective for BC Hydro on April 1, 2019. BC Hydro has made estimates based on its preliminary assessment regarding the impacts of IFRS 16 and has included them in this Application. However, the actual impacts of the new standard may vary from these estimates as BC Hydro completes its assessment, including as a result of clarifications and interpretive guidance that may be developed by the International Accounting Standards Board, accounting firms and industry groups to assist in the implementation of the new standard. BC Hydro anticipates that material variances are possible when we complete our assessment of EPAs, including the review by our external auditors. As shown in Chapter 8, section 8.12.1, BC Hydro has deferred positive variances related to EPA capital leases into the Non-Heritage Deferral Account in order to provide the benefit to ratepayers, even though this was not required under existing orders.

Therefore, in this application, BC Hydro requests BCUC approval to:

- Defer any variances related to the accounting for EPAs determined to be leases under IFRS 16, which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account.

7.7.1.3 Biomass Energy Program

As discussed in Chapter 4, section 4.3.2, the Comprehensive Review included the announcement of the Biomass Energy Program. The Government of B.C. indicated that it intends to provide a direction to the BCUC with respect to the approval of the program documentation and require the costs associated with the Biomass Energy Program to be recovered from ratepayers.

BC Hydro may be required to account for some of the costs associated with the Biomass Energy Program as amounts other than cost of energy (variances related to which would generally be deferred to the Non-Heritage Deferral Account pursuant to existing orders). Until contracts relating to the identified biomass projects are completed, BC Hydro cannot have certainty on the amount of those costs or how to appropriately account for them.

BC Hydro proposes that variances related to the Biomass Energy Program be deferred to the Non-Heritage Deferral Account.

Therefore, in this application, BC Hydro requests BCUC approval to:

- Defer any variances between forecast and actual amounts related to the Biomass Energy Program which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account. This will allow BC Hydro to recover its costs with respect the Biomass Energy Program.[328]

7.7.2 Dismantling Cost Regulatory Account

By Order No. G-47-18 to the Previous Application, the BCUC approved the deferral of variances between forecast and actual dismantling costs over the fiscal 2017 to fiscal 2019 test period, the application of interest to the account, and the recovery of the forecast account balance at the end of the test period over the next test period. BC Hydro is proposing to continue the Dismantling Cost Regulatory Account on an ongoing basis.

[328] The Government of B.C. has indicated that it intends to provide a direction to the BCUC with respect to the approval of the program documentation and to require the costs associated with the program to be recovered from ratepayers.

In its Decision, the BCUC stated that, in its view, the timing of dismantling activities is largely within BC Hydro's control but that the establishment of the account for the test period would allow BC Hydro to gain more experience with forecasting the timing of expenditures.[329]

BC Hydro is not in a better position now than it was over the last test period to forecast dismantling costs accurately. In BC Hydro's view, the nature of dismantling costs makes them difficult to forecast accurately. As shown in the table below, dismantling cost variances can be positive or negative and continue to be significant in recent years. More specifically, Table 7-5 shows that variances have ranged from $14.1 million below plan to $31.7 million above plan (with a range between -41 per cent to +89 per cent of plan) since fiscal 2012.

Table 7-5 Dismantling Cost Variances Fiscal 2012 to Fiscal 2018 Actual and Fiscal 2019 Forecast

	($ million)	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019
		1	2	3	4	5	6	7	8
1	Actual[1]	20.2	16.4	32.2	22.4	24.2	42.4	67.5	44.5
2	RRA Plan	34.3	20.9	21.0	24.6	31.2	39.5	35.7	30.6
3	Variance from Plan (Actual - RRA Plan)	(14.1)	(4.5)	11.2	(2.2)	(7.0)	2.9	31.7	13.9
3	% Variance from Plan	-41%	-21%	53%	-9%	-22%	7%	89%	45%

[1]F2019 is a forecast amount

Actual dismantling costs can vary significantly from planned amounts for a number of reasons.

The rationale for the Dismantling Cost Regulatory Account is the same as the rational for the Amortization of Capital Additions Regulatory Account, which captures variances between forecast and actual amortization of capital additions. Dismantling costs are largely driven by BC Hydro's capital plan and are impacted by capital project schedules. Similar to capital projects, dismantling projects may be forecast

[329] BCUC Decision and Order No. G-47-18, BC Hydro Previous Application (March 1, 2018), pages 62 to 63.

well in advance of the actual work taking place. Project estimates may be from an earlier stage of the project lifecycle and will have different degrees of accuracy depending on the phase of the project.

In addition, actual dismantling costs are expected to differ from forecast amounts due to differences in timing and scope. Dismantling work occurs based on capital project schedules, which can change and cause material shifts in the timing of dismantling expenditures. Any delays or advancements to capital project schedules could result in these expenditures being incurred earlier or later than planned. In addition, as additional work requirements may be determined as activities progress, the full scope and cost of dismantling activities may not be known until the work is underway.

Further, emergency dismantling of assets is sometimes required and unplanned dismantling may be required for projects that were not included in the dismantling cost forecast in a given test period. For example, in fiscal 2018, BC Hydro decommissioned the Salmon River Diversion, which was originally planned to be upgraded, resulting in unplanned dismantling cost expenditures. By Order No. G-96-17, the BCUC approved BC Hydro’s request to decommission the Salmon River Diversion and allowed the decommissioning costs to be transferred to the Dismantling Costs Regulatory Account. This transfer meant that these dismantling costs were appropriately recovered from ratepayers.

BC Hydro believes that it is appropriate to continue to defer, on an ongoing basis, the variances between forecast and actual dismantling costs, for recovery over the next test period. There are significant dismantling costs planned during the test period in the amount of $67 million in fiscal 2020 and $43 million in fiscal 2021. In the absence of the Dismantling Cost Regulatory Account, significant gains or losses could accrue to ratepayers or the Government of B.C. as BC Hydro’s shareholder. Continued use of the account for the test period will mean that ratepayers pay the actual costs of dismantling activities.

Therefore, in this application, BC Hydro is requesting BCUC approval to:

- Continue to defer, on an annual and ongoing basis, any variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account;
- Continue to apply interest to balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro's current weighted average cost of debt;
- Effective starting in fiscal 2020, and on an ongoing basis, recover the forecast interest charged to the Dismantling Cost Regulatory Account each year from the account each year; and
- On an ongoing basis, recover the forecast account balance at the end of a test period over the next test period.

7.7.3 DSM Regulatory Account

By Order No. G-55-95, the BCUC directed the deferral and recovery of costs associated with DSM activities. In accordance with Direction No. 7, BCUC Order No. G-48-14 authorized BC Hydro to continue to defer these costs to the DSM Regulatory Account and to amortize the balance of the account into rates over 15 years, on an ongoing basis.

The Direction to the BCUC Respecting the Authority's TMP Program (Order in Council No. 404, issued on July 14, 2015) specified that BC Hydro be allowed to defer costs incurred related to the Thermo-Mechanical Pulp program, up to $100 million, to the DSM Regulatory Account. BC Hydro's forecast costs related to the Thermo-Mechanical Pulp Program are discussed in Chapter 10.

The Direction to the BCUC Respecting Undertaking Costs (Order in Council No. 100, issued on March 1, 2017) specified that BC Hydro be allowed to defer low-carbon electrification expenditures, to the DSM Regulatory Account.

BC Hydro's forecast costs related to low carbon electrification are discussed in Chapter 10.

In this application, BC Hydro requests BCUC approval to:

- Defer low-carbon electrification expenditures to the DSM Regulatory Account, consistent with the Direction to the BCUC Respecting Undertaking Costs.

7.7.4 Site C Regulatory Account

By Order No. G-143-06, the BCUC approved the creation of a regulatory account related to Site C Project expenditures and approved deferral of project costs incurred in fiscal 2007 and fiscal 2008 to the account. The Fiscal 2009 to Fiscal 2010 Revenue Requirements Application Decision and Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement extended the deferral of project costs to the Site C Regulatory Account to the end of fiscal 2011. By Order No. G-77-12A to the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirement Application, the BCUC authorized the deferral of all operating costs incurred related to the Site C Project in fiscal 2012 to fiscal 2014. By Order No. G-48-14, the BCUC authorized the deferral of all operating costs incurred in fiscal 2015 and fiscal 2016.

Following the final investment decision by the Government of B.C. to proceed with the Site C Project, BC Hydro commenced capitalization of costs related to the project starting in January 2015. While BC Hydro has commenced capitalization of costs, certain costs related to the project may not be eligible for capitalization under IFRS. For example, some legal costs are not eligible for capitalization under IFRS.

By Order No. G-47-18 to the Previous Application, the BCUC approved the deferral of any costs related to the Site C Project that are not able to be capitalized under the Prescribed Standards, to the Site C Regulatory Account.

As discussed in Chapter 8, section 8.13, BC Hydro has fully adopted IFRS, effective for its fiscal year ending March 31, 2019. As a result, the reference to the

"Prescribed Standards" should be removed from the scope of what may be deferred to the Site C Regulatory Account. Consistent with the BCUC's prior Orders, this would allow BC Hydro to continue to defer to the Site C Regulatory Account any costs related to the Site C Project that are not able to be capitalized.

As described in Chapter 8, section 8.13.4, as a result of the adoption of IFRS 14, the amortization of the Debt Management Regulatory Account can no longer be classified as finance charges and as such can no longer be included in the calculation of BC Hydro's interest during construction that is applied to capital projects (i.e., capitalized).

For the test period, BC Hydro forecasts that the amount of interest during construction attributable to the Site C Project that can no longer be capitalized is $2.0 million in fiscal 2020 and $2.7 million in fiscal 2021. These are credit amounts as the Debt Management Regulatory Account is currently in a credit balance. As these amounts can no longer be capitalized under IFRS, they would be deferred to the Site C Regulatory Account.

Therefore, in this application, BC Hydro is requesting BCUC approval to remove the reference to the "Prescribed Standards" from the scope of what may be deferred to the Site C Regulatory Account, as BC Hydro has fully adopted IFRS. This will allow BC Hydro to continue to defer to the Site C Regulatory Account any costs related to the Site C Project that are not able to be capitalized.

7.7.5 Capital Project Investigation Costs Regulatory Account

By Order No. G-16-09 to the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, the BCUC approved the establishment of a regulatory account for capital project investigation costs. The Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement provided that additions to the Capital Project Investigation Costs Regulatory Account would be discontinued at the end of fiscal 2011, and that the closing fiscal 2011 balance would be amortized beginning in fiscal 2012. BCUC Order No. G-77-12A approved the amortization of the fiscal 2011 closing balance over a 10 year period, commencing in fiscal 2012. Consistent with BCUC Order No. G-77-12A, the balance in this account will be fully amortized into rates by the end of fiscal 2021.

Therefore, in this application, BC Hydro is requesting BCUC approval to:

- Close the Capital Project Investigation Costs Regulatory Account at the end of fiscal 2021 as its balance will be fully amortized into rates at that time.

7.7.6 Rate Smoothing Regulatory Account

In accordance with Direction No. 7, BCUC Order No. G-48-14 established the Rate Smoothing Regulatory Account in fiscal 2015 to defer, for recovery in rates in future fiscal years, those portions of the allowed revenue requirement in a particular fiscal year that were not to be recovered in rates in that particular fiscal year.

Approved additions to this regulatory account from fiscal 2015 to fiscal 2019 total $1.136 billion. As a result of the Comprehensive Review, BC Hydro ceased using the Rate Smoothing Regulatory Account at the end of the third quarter of fiscal 2019. The balance of the Rate Smoothing Regulatory Account was written-off in December 2018 in the amount of $1.044 billion, resulting in a reduction to BC Hydro’s retained earnings and a forecast net loss for BC Hydro in fiscal 2019. This means that the cost of the write-off is borne by the Government of B.C. as BC Hydro’s shareholder, and not by ratepayers. As a result, there is a zero balance in the Rate Smoothing Regulatory Account at the beginning of the test period. BC Hydro is not proposing to smooth rates over the fiscal 2020 to fiscal 2021 test period.

Therefore, in this application, BC Hydro is requesting BCUC approval to:

- Close the Rate Smoothing Regulatory Account in fiscal 2020 as this account has a zero balance and BC Hydro is not proposing to smooth rates over the fiscal 2020 to fiscal 2021 test period.

7.8 BC Hydro is Not Seeking Changes to Most Regulatory Accounts

Consistent with prior applications, provided below is an overview of the history and recovery periods of the regulatory accounts for which BC Hydro is not seeking any changes.

7.8.1 Storm Restoration Costs Regulatory Account

By Order No. G-16-09 to the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, the BCUC approved the ongoing deferral of the difference between actual storm related restoration costs and the average of the actual storm restoration costs for the five most recent normal weather years. Fiscal 2014 through fiscal 2018 comprise the five most recent normal weather years and result in an average annual storm restoration cost of $17.8 million. BC Hydro has included this amount for storm restoration costs in its fiscal 2020 and fiscal 2021 operating costs plan.

In recent years, BC Hydro has experienced more frequent storms and extreme weather resulting in higher storm-related expenditures, which has caused the five-year average to increase as shown in Table 7-6 below.

Table 7-6 Storm Restoration Costs Fiscal 2014 to Fiscal 2018 Actual

	($ million)	F2014 Actual	F2015 Actual	F2016 Actual	F2017 Actual	F2018 Actual	F2014-F2018 Average
		1	2	3	4	5	6
1	Storm Restoration Costs	4.6	12.9	23.5	25.3	22.9	**17.8**

By Order No. G-47-18 to the Previous Application, the BCUC approved that interest continue to be applied to the balance of this regulatory account and that the forecast account balance at the end of a test period be recovered over the next test period. Interest is applied to the account based on BC Hydro's weighted average cost of debt and forecast interest is recovered from the account each year.

BC Hydro is not requesting any changes to this account in this application.

7.8.2 Amortization of Capital Additions Regulatory Account

By Order No. G-16-09, the BCUC directed BC Hydro to defer to a regulatory account any differences between forecast and actual amortization of capital additions. In its Decision, the BCUC stated that:

> "the most effective solution to ensuring that amortization charges collected in revenue requirements for the test period appropriately reflect the capital assets that are actually utilized for the benefit of ratepayers during the same test period is to establish a new regulatory account."[330]

The Amortization of Capital Additions Regulatory Account was continued in the Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement, the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application and the Fiscal 2015 to Fiscal 2016 Revenue Requirements Rate Application. By Order No. G-47-18 to the Previous Application, the BCUC approved that this regulatory account continue on an ongoing basis, that interest continue to be applied to the balance of this regulatory account, and that the forecast account balance at the end of a test period be recovered over the next test period. Interest is applied to the account based on BC Hydro's weighted average cost of debt and forecast interest is recovered from the account each year.

BC Hydro is not requesting any changes to this account in this application.

7.8.3 Total Finance Charges Regulatory Account

By Order No. G-16-09 to the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, the BCUC directed BC Hydro to defer to a regulatory account any differences between forecast and actual finance charges for fiscal 2009 and fiscal 2010. The Total Finance Charges Regulatory Account was continued by BCUC decisions on the Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement, the Fiscal 2012 to Fiscal 2014 Amended Revenue

[330] Fiscal 2009 to Fiscal 2010 Revenue Requirement Application Decision, page 191.

Requirements Application and the Fiscal 2015 to Fiscal 2016 Revenue Requirements Rate Application. By Order No. G-47-18 to the Previous Application, the BCUC approved the continuation of this regulatory account on an ongoing basis, and that the forecast account balance at the end of a test period be recovered over the next test period.

BC Hydro is not requesting any changes to this account in this application.

7.8.4 Rock Bay Remediation Regulatory Account

By Order No. G-75-11, the BCUC approved the establishment of the Rock Bay Remediation Regulatory Account for the deferral of actual expenditures in fiscal 2011 related to the remediation of BC Hydro's Rock Bay property. By Order No. G-55-12, the account was extended to defer actual remediation costs incurred in fiscal 2012. By Order No. G-57-13, the account was extended to defer actual remediation costs incurred in fiscal 2013.

As required by Direction No. 7, Order No. G-48-14 extended this period to include remediation costs incurred in fiscal 2014 and later fiscal years. Direction No. 6 directed the amortization of specific amounts from the regulatory account in fiscal 2015 and fiscal 2016.

The actual remediation costs deferred to the regulatory account for fiscal 2015 and fiscal 2016 were lower than the amortization amounts specified by Direction No. 6, resulting in a closing credit balance at the end of fiscal 2016. BCUC Order No. G-47-18 to the Previous Application approved the refund of the closing fiscal 2016 credit balance to ratepayers over the fiscal 2017 to fiscal 2019 period.

BCUC Order No. G-47-18 also approved the deferral of actual Rock Bay remediation costs to this regulatory account each year and the amortization of forecast Rock Bay remediation costs from this account each year from fiscal 2017 onwards. The Order also approved that interest continue to be applied to the balance of this regulatory account and that the forecast account balance at the end of a test period be recovered over the next test period. Interest is applied to the account based on BC Hydro's weighted average cost of debt and forecast interest is recovered from the account each year.

Actual remediation costs over the fiscal 2017 to fiscal 2019 period were lower than forecast remediation costs, resulting in a forecast closing credit balance in the account at the end of fiscal 2019 of $20.5 million. Consistent with BCUC Order No. G-47-18, this credit balance will be refunded to ratepayers over the fiscal 2020 to fiscal 2021 test period.

Remediation of the Rock Bay property was completed in fiscal 2019 and BC Hydro is not forecasting the deferral of any further remediation costs to this account over the test period. However, there may be minor variances between fiscal 2019 forecast and actual costs and forecast and actual interest applied to this account during the test period. Therefore, BC Hydro plans to seek BCUC approval to close the account in the next test period, once the balance of the account has been fully recovered.

BC Hydro is not requested any changes to this account in this application.

7.8.5 Arrow Water Systems Regulatory Account

In the mid-1960s, BC Hydro relocated residents affected by the creation of the Hugh Keenleyside Dam and Arrow Lakes Reservoir to the newly constructed towns of Edgewood, Fauquier and Burton as well as the existing town of West Robson, all part of the Regional District of Central Kootenay. BC Hydro built the drinking water systems in Burton, Fauquier, and Edgewood when the towns were constructed, and upgraded and assumed control of the West Robson drinking water system (collectively known as the Arrow Water Systems) to compensate for impacts related to construction of the Keenleyside Dam. On January 4, 2011, BC Hydro divested the assets of the Arrow Water Systems to the Regional District of Central Kootenay.

By Order No. G-90-11, the BCUC approved the deferral of costs related to the divestiture of the Arrow Water Systems and established the Arrow Water Systems Regulatory Account and the Arrow Water Systems Provision Regulatory Account. The Arrow Water Systems Provision Regulatory Account is discussed further in section 7.8.19. Order No. G-48-14 set the amortization for the Arrow Water Systems Regulatory Account at $4.7 million in fiscal 2015 and $4.5 million in fiscal 2016, which reflected divestiture costs incurred to date.

Under the terms of the agreement with the Regional District of Central Kootenay on the divestiture of the Arrow Water Systems assets, BC Hydro makes an annual payment to the Regional District of Central Kootenay. This payment covers the water fees for the residents in the region who had water accounts in good standing with BC Hydro at the time of the transfer. BC Hydro will continue to make these payments until qualified residents are no longer on title for their properties. The cost of these payments is estimated at $0.3 million per year. Consistent with BCUC Order No. G-47-18 to the Previous Application, this amount, and any other expenditures associated with divestiture are transferred from the Arrow Water Systems Provision Regulatory Account to the Arrow Water Systems Regulatory Account and a corresponding amount is amortized annually from the Arrow Water Systems Regulatory Account.

BC Hydro is not requesting any changes to this account in this application.

7.8.6 Remediation Regulatory Account

Starting in fiscal 2013 and in following years, BC Hydro began to incur expenditures related to asbestos remediation at its facilities. By Order No. G-7-13 the BCUC approved the establishment of the Asbestos Remediation Regulatory Account for unplanned asbestos remediation costs in fiscal 2013 and fiscal 2014. In accordance with Direction No. 7, BCUC Order No. G-48-14 authorized BC Hydro to continue to defer variances between forecast and actual asbestos remediation costs, to the account, on an ongoing basis.

By Order No. G-47-18 to the Previous Application, the BCUC approved an expansion of the account scope to include costs incurred related to the compliance with polychlorinated biphenyl regulations. To reflect this change, the BCUC also approved that the name of the account be changed to the Remediation Regulatory Account.

By Order No. G-47-18, the BCUC approved, starting in fiscal 2017, and on an ongoing basis, that actual expenditures related to compliance with polychlorinated biphenyl regulations and asbestos remediation be deferred to this account each year, and forecast expenditures related to compliance polychlorinated biphenyl regulations and asbestos remediation be amortized from this account each year. Order No. G-47-18 also approved that interest continue to be applied to the balances in the account and that the forecast account balance at the end of a test period be recovered over the next test period. Interest is applied to the account based on BC Hydro's weighted average cost of debt and forecast interest is recovered from the account each year.

It continues to be appropriate to defer variances related to asbestos remediation to the Remediation Regulatory Account. The rationale for deferring these variances is the same as the rationale accepted by the BCUC for the deferral of variances related to compliance with polychlorinated biphenyl regulations. In its Decision to the Previous Application, the BCUC stated that:

> *"Although the treatment of PCB is not prescribed by Direction No. 7, as it is for asbestos costs, the Panel concurs with BC Hydro that PCB costs are similar in nature to asbestos costs in that they involve long-term estimates, the actual expenditures are susceptible to variances in amount and timing and differences from forecast due to the timing and scope of work undertaken. Furthermore, the Panel finds the consistent treatment of asbestos and PCB costs is reasonable."*[331]

[331] BCUC Order No. G-47-18, Previous Application, page 65.

BC Hydro is not requesting any changes to this account in this application.

7.8.7 Real Property Sales Regulatory Account

By Order No. G-48-14, the Real Property Sales Regulatory Account was established to defer the variances between BC Hydro's actual and forecast real property gain/loss from real estate sales, with interest to be applied to the account based on BC Hydro's weighted average cost of debt. As described in section 7.9, BC Hydro incurs finance charges related to the balances in regulatory accounts. Accordingly, it is appropriate to apply interest to this regulatory account, consistent with the application of interest to other cash variance accounts.

The timing of completion of real estate transactions is difficult to forecast accurately. The Real Property Sales Regulatory Account smooths the recognition of gains and losses from real property sales that could otherwise impact rates in a particular year.

Since fiscal 2015, BC Hydro has been preparing surplus properties for sale. Activities have included market value appraisals and estimates, investigation and remediation of environmental contamination, working with municipalities on subdivision requirements, and consultation with First Nations.

The 2013 10 Year Rates Plan included a target of $50 million of net gains from real property sales from fiscal 2015 to fiscal 2019. Consistent with this target, BC Hydro included $10 million in forecast net gains from real property sales in each fiscal year in both the Fiscal 2015 to Fiscal 2016 Revenue Requirements Rate Application and the Previous Application.

BC Hydro has increased our net gains target from $50 million to $100 million and extended the timeframe to achieve this target to the end of fiscal 2024. This means that the Real Property Sales Regulatory Account is expected to self-clear based on the forecast gains and losses experienced from fiscal 2020 to fiscal 2024 and is forecast to have a zero balance by the end of fiscal 2024, subject to potential interest charges.

Consistent with this revised target, BC Hydro has included $10 million in forecast net gains from real property sales in both fiscal 2020 and fiscal 2021, in this application.

Pursuant to Direction No. 8, the existing balance in this regulatory account as at March 31, 2019, is recoverable from ratepayers. If this regulatory account was discontinued at the end of fiscal 2019, the balance would be amortized into rates starting in fiscal 2020. However, the revised target of $100 million in net gains from real property sales is expected to clear the balance in this regulatory account by the end of fiscal 2024. Maintaining the Real Property Sales Regulatory Account means that the existing account balance will not be borne by ratepayers.

BC Hydro is not requesting any changes to this account in this application.

7.8.8 Mining Customer Payment Plan Regulatory Account

In accordance with section 3(2) of Order in Council No. 123, issued on February 29, 2016, BCUC Order No. G-34-16 authorized BC Hydro to establish the Mining Customer Payment Plan Regulatory Account to defer to future fiscal years amounts equal to the sum of the following related to mining customers participating in the Mining Customer Payment Plan Program:

(i) The account balances of mining customers, if those account balances are impaired;

(ii) Any other amounts that are payable to BC Hydro by mining customers before the closing date and that are impaired; and

(iii) Any taxes paid by BC Hydro on behalf of mining customers on the account balances referred to in subparagraph (i) and amounts referred to in subparagraph (ii).

This Order arose from the Government of B.C.’s decision to allow companies operating metal and coal mines in B.C. to temporarily defer a portion of their electricity payments during periods of low commodity prices.

BCUC Order No. G-34-16 also directed BC Hydro to reduce the Mining Customer Payment Plan Regulatory Account by an amount collected from an applicable mining customer, and to include in the account, interest determined in a fiscal year at the rate of BC Hydro's weighted average cost of debt in that fiscal year.

BC Hydro is not requesting any changes to this account in this application.

7.8.9 Customer Crisis Fund Regulatory Account

By Order No. G-166-17, the BCUC approved the establishment of the Customer Crisis Fund Regulatory Account.

By Order No. G-5-17 to the 2015 Rate Design Application, the BCUC directed BC Hydro to file a proposal for the establishment of a crisis intervention fund pilot program for residential customers who have arrears with BC Hydro and are unable to pay their electricity bills.[332] By Order No. G-166-17, the BCUC approved the Customer Crisis Fund pilot program on a three year basis.

The costs related to the Customer Crisis Fund pilot program are driven by program participation and could vary from forecast. In addition, there will likely be variations in the timing of revenues and costs over the duration of the Customer Crisis Fund pilot program.

Accordingly, in its application to establish the pilot program, BC Hydro proposed that the net difference between the revenues collected under the Customer Crisis Fund Rate Rider and the incremental costs related to the Customer Crisis Fund pilot program in each fiscal year be transferred to the Customer Crisis Fund Regulatory Account. Any remaining balance in the Customer Crisis Fund Regulatory Account at the end of the Customer Crisis Fund pilot program would be to the account of residential ratepayers. Recovery or refund of the balance will be addressed after

[332] 2015 Rate Design Application Decision, BCUC Order No. G-5-17, pages 97 to 98.

completion of the pilot program. This approach ensures that residential ratepayers only pay the actual net costs of the Customer Crisis Fund pilot program.

BC Hydro is not requesting any changes to this account in this application.

7.8.10 Foreign Exchange Gains and Losses Regulatory Account

By Order No. G-47-02, the BCUC approved the deferral and amortization of foreign exchange gains and losses on the translation of foreign denominated long-term monetary items, using the straight-line pool method, from fiscal 2003 onwards. More specifically, deferred foreign currency translation gains and losses related to long-term debt are amortized over the weighted average remaining term to maturity of the foreign denominated long-term debt portfolio. Deferred foreign currency translation gains and losses related to sinking funds are amortized over the weighted average remaining term to maturity of the sinking fund portfolio.

BC Hydro is not requesting any changes to this account in this application.

7.8.11 Non-Current Pension Costs Regulatory Account

By Order No. G-16-09 to the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, the BCUC approved the establishment of a regulatory account to defer the difference between forecast and actual non-current pension costs in fiscal 2010. The Fiscal 2011 Revenue Requirement Application Negotiated Settlement Agreement extended this regulatory account for fiscal 2011 and directed that the closing fiscal 2011 balance be amortized over a five-year period, beginning in fiscal 2012.

BCUC Order No. G-77-12A extended the account for fiscal 2012 to fiscal 2014, and expanded the scope of the account to include the difference between forecast and actual non-current other post-employment benefit costs, beginning in fiscal 2012. In accordance with Direction No. 7, BCUC Order No. G-48-14 authorized BC Hydro to continue to defer to the account variances between forecast and actual non-current pension costs, on an ongoing basis.

By Order No. G-47-18 to the Previous Application, the BCUC approved that the portion of the forecast account balance at the start of a test period related to the variances transferred to the account during the previous test period be amortized over the expected average remaining service life (**EARSL**) of the active plan members at the start of the test period. EARSL is determined by BC Hydro's actuary and is currently 12 years.

In accordance with BCUC Order No. G-47-18, the discount rate used to forecast post-employment benefit plan costs is based on the market discount rate in effect at the time the forecast was prepared.

As discussed in section 7.3, actuarial gains and losses are sensitive to changes in market discount rates, rates of return on pension plan assets and significant changes in key actuarial assumptions. This means that annual actuarial gains and losses are subject to large positive and negative fluctuations. For example, the elimination of Medical Services Plan Premiums resulted in significant actuarial gains in fiscal 2018 and fiscal 2019 as shown in Schedule 2.2 of Appendix A. In the absence of regulatory approval to defer actuarial gains and losses to the Non-Current Pension Costs Regulatory Account, this actuarial gain would have been captured in retained earnings and ratepayers would not have received the benefit of this actuarial gain. Accordingly, BC Hydro believes it is appropriate to continue to defer, on an ongoing basis, the variances between its actual and forecast non-current pension costs to the Non-Current Pension Costs Regulatory Account and to continue to amortize these amounts over EARSL.

Please refer to Chapter 5G, section 5G.9 for further information on Non-Current Service Costs.

BC Hydro is not requesting any changes to this account in this application.

7.8.12 PEB Current Pension Costs Regulatory Account

By Order No. G-47-18 to the Previous Application, the BCUC approved the establishment of the Post-Employment Benefit (PEB) Current Pension Costs Regulatory Account to defer the annual variance between forecast and actual costs related to the operating cost portion of post-employment benefits current pension costs, on an ongoing basis. Order No. G-47-18 also approved that the forecast account balance at the end of a test period be recovered over the next test period.

In accordance with BCUC Order No. G-47-18, the discount rate used to forecast post-employment benefit plan costs is based on the market discount rate in effect at the time the forecast was prepared.

Please refer to Chapter 5G, section 5G.9 for further information on Current Service Costs.

BC Hydro is not requesting any changes to this account in this application.

7.8.13 Debt Management Regulatory Account

By Order No. G-42-16, the BCUC approved the establishment of the Debt Management Regulatory Account, to capture mark-to-market gains and losses of financial contracts that hedge future long-term debt. Hedging the interest rate on future long-term debt enables BC Hydro to mitigate interest rate risk on future long-term debt issuances.

Since fiscal 2017, BC Hydro has locked in interest rates on forecast future long-term debt issuances by entering into financial contracts that hedge the interest rate risk in order to create certainty of financing costs associated with future planned expenditures. In accordance with Order No. G-42-16, the gains and losses from financial contracts that hedge future long-term debt are recorded in the Debt Management Regulatory Account and amortized over the remaining term of the associated long-term debt issuances. These gains and losses are amortized in the test period following the test period in which the long-term debt associated with a particular hedge is issued.

BC Hydro is not requesting any changes to this account in this application.

7.8.14 First Nations Costs Regulatory Account

By Order No. G-53-02, the BCUC approved the deferral of costs related to negotiations and settlements with First Nations, and approved the amortization of actual negotiation costs and approved settlement costs, over a ten-year period. Settlement payments transferred to the First Nations Costs Regulatory Account from the First Nations Provisions Regulatory Account are not amortized or recovered in rates, pending BCUC approval to do so. In accordance with BCUC Order No. G-11-08, when a settlement is completed, BC Hydro must submit an application to the BCUC for approval to recover the settlement payment in rates. The nature of these settlements is discussed further in section 7.8.17. BCUC Order No. G-48-14 directed the amortization of specific amounts from the account for fiscal 2015 and fiscal 2016, and also directed that interest be applied on the account going forward.

Actual transfers to the account in fiscal 2015 and fiscal 2016 were different from the amounts on which the specific amortization in BCUC Order No. G-48-14 was based, which resulted in BC Hydro recording higher amortization than if the amortization had been calculated on actual transfers. This resulted in a credit amount which was refunded to ratepayers over the fiscal 2017 to fiscal 2019 period, consistent with BCUC Order No. G-47-18 to the Previous Application.

As described in section 7.9, BC Hydro incurs finance charges related to the balances in regulatory accounts. Accordingly, it is appropriate that interest should be applied to this regulatory account, consistent with the application of interest to other cash variance accounts.

By Order No. G-47-18 to the Previous Application, the BCUC approved, starting in fiscal 2017, and on an ongoing basis that:

(i) Actual lump sum settlement payments be deferred to this account each year, and forecast lump sum settlement payments be amortized over a ten-year period, starting in the year of payment;

(ii) Actual annual settlement payments be deferred to this account each year, and forecast annual settlement payments be amortized in the year of payment;

(iii) Actual negotiation costs be deferred to this account each year, and actual negotiation costs be recovered from the account each year;

(iv) Interest continue to be applied to the balances in the account, consistent with the application of interest to other variance accounts, based on BC Hydro's weighted average cost of debt, and forecast interest charged to the account be amortized from the account each year;

(v) The forecast account balance at the end of a test period related to the difference between the amortization of the forecast annual and lump sum settlement payments and the calculation of amortization based on the actual annual and lump sum settlement payments during that test period be recovered over the next test period; and

(vi) The forecast account balance at the end of a test period related to the difference between the forecast interest recovered and the actual interest charged to the account during that test period be recovered over the next test period.

For items (i) and (ii) above, the year of payment refers to the year the payment is forecast to be made.

BC Hydro is not requesting any changes to this account in this application.

7.8.15 Pre-1996 Contributions in Aid of Construction Regulatory Account

In fiscal 2006 BC Hydro retained Gannett Fleming to complete a depreciation study, which was filed as part of the Fiscal 2007 to Fiscal 2008 Revenue Requirements Application. Gannett Fleming recommended that the amortization period for assets referred to as “Profile ID 99403 Distribution Pre-1996 Contributions in Aid” be increased from the then-approved period of 25 years to 45 years.

However, section 7(iv) of the Fiscal 2007 to Fiscal 2008 Revenue Requirements Application Negotiated Settlement Agreement approved by BCUC Order No. G-143-06 committed BC Hydro to maintain the amortization period for these assets at 25 years. In its financial records BC Hydro changed the amortization period for these assets from 25 to 45 years to match the depreciation study, and implemented the Fiscal 2007 to Fiscal 2008 Revenue Requirements Application Negotiated Settlement Agreement commitment by creating a regulatory account to capture the difference in the revenue requirement impacts of a 45-year amortization period and a 25-year amortization period. This regulatory account will be fully amortized at the end of fiscal 2040.

BC Hydro is not requesting any changes to this account in this application.

7.8.16 SMI Regulatory Account

By Order No. G-64-09, the BCUC approved the establishment of the SMI (Smart Metering and Infrastructure Program) Regulatory Account to defer the operating costs incurred by BC Hydro related to the Smart Metering and Infrastructure Program in fiscal 2009. By Order No. G-67-10, the BCUC approved the deferral of these costs for fiscal 2010. BCUC Order No. G-115-11 authorized BC Hydro to include its actual fiscal 2011 Smart Metering and Infrastructure Program operating costs up to $5.8 million in the SMI Regulatory Account. BCUC Order No. G-77-12A to the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application approved the deferral of actual net operating costs, amortization on capital assets, finance charges, and return on equity related to the SMI program from fiscal 2012 to fiscal 2014, to the SMI Regulatory Account.

By Order No. G-166-13, and in accordance with section 3(2) of Direction No. 4, BC Hydro was directed to defer to the account:

- Program costs;
- Investigation costs and infrastructure costs that are not recovered from eligible customers at premises where a legacy meter or radio-off meter is installed; and
- Costs related to smart meters, which are incurred during the period January 1, 2013 to March 31, 2014.

By Order No. G-48-14 to the Fiscal 2015 to Fiscal 2016 Revenue Requirements Rate Application, the BCUC approved the amortization of specific amounts in fiscal 2015 and fiscal 2016 from the SMI Regulatory Account and also approved deferral of the net operating costs incurred in fiscal 2015 to fiscal 2016 related to the SMI Program, to the account. As the SMI Program is now complete and operationalized, no further additions are being made to this regulatory account.

By Order No. G-47-18 to BC Hydro's Previous Application, the BCUC approved the recovery of the fiscal 2016 closing account balance over a period of 13 years, starting in fiscal 2017, which is the remaining period of the original 15-year amortization period proposed in the Regulatory Accounts Report filed in the Fiscal 2015 to Fiscal 2016 Revenue Requirements Rate Application. The 15-year amortization is based on the average life of SMI assets. BCUC Order No. G-47-18 also approved that interest continue to be applied to the balance of this regulatory account. Interest is applied to the account at BC Hydro's weighted average cost of debt and forecast interest is recovered from the account each year.

BC Hydro is not requesting any changes to this account in this application.

7.8.17 First Nations Provisions Regulatory Account

By Order No. G-56-06, the BCUC approved the establishment of a regulatory asset corresponding to the amount of a loss provision that BC Hydro recorded on its financial statements as required under the accounting standards related to two First Nations claims. By Order No. G-11-08, the BCUC amended the First Nations Provisions Regulatory Account to allow the balance of the regulatory account to reflect loss provisions as required under the accounting standards, related to any First Nations claim, and to allow the periodic adjustment of the balance of the regulatory account to reflect adjustments to the loss provisions required under the accounting standards.

BC Hydro's settlements with First Nations may include both lump sum payments and annual payments. When settlement payments are made, corresponding amounts are transferred from the First Nations Provisions Regulatory Account to the First Nations Costs Regulatory Account, and recovered in rates through amortization of that regulatory account, as discussed in section 7.8.14.

BC Hydro is not requesting any changes to this account in this application.

7.8.18 Environmental Provisions Regulatory Account

By Order No. G-88-10, the BCUC approved the establishment of the Environmental Provisions Regulatory Account in the amount of the loss provision liability recognized by BC Hydro in its financial statements, related to compliance with the polychlorinated biphenyl regulations and remediation of environmental contamination at Rock Bay. Order No. G-88-10 also approved periodic adjustments to the amounts in the regulatory account to match the changes required under the accounting standards in the loss provision liability. By Order No. G-7-13, the terms of the Environmental Provisions Regulatory Account were expanded to include the loss provision liability related to asbestos remediation at BC Hydro's facilities.

As BC Hydro makes actual expenditures related to compliance with the polychlorinated biphenyl regulations, the remediation of Rock Bay and the remediation of asbestos at its facilities, the balance in the Environmental Provisions Regulatory Account is reduced accordingly.

Actual costs of remediation activities at Rock Bay are deferred to the Rock Bay Remediation Regulatory Account as they are incurred, as described in section 7.8.4, and the provision is reduced by an equal amount. Remediation of the Rock Bay property was completed in fiscal 2019, and the balance in the Environmental Provisions Regulatory Account related to Rock Bay has been reduced accordingly.

Actual costs related to asbestos remediation are deferred to the Remediation Regulatory Account as they are incurred, as described in section 7.8.6, and the provision is reduced by an equal amount.

Actual costs related to compliance with polychlorinated biphenyl regulations, were expensed as incurred until the end of fiscal 2016, and the Environmental Provisions Regulatory Account was reduced by an equal amount. By Order No. G-47-18 to the Previous Application, BCUC approved that, starting in fiscal 2017, and on an ongoing basis, actual costs related to compliance with polychlorinated biphenyl regulations be deferred to the Remediation Regulatory Account as they are incurred and the provision be reduced by an equal amount. This is similar to the treatment of the costs associated with asbestos remediation.

The actual balances in the Rock Bay Remediation Regulatory Account and the Remediation Regulatory Account are recovered through the mechanisms discussed in sections 7.8.4 and 7.8.6, respectively.

BC Hydro is not requesting any changes to this account in this application.

7.8.19 Arrow Water Systems Provision Regulatory Account

By Order No. G-90-11, the BCUC approved the establishment of the Arrow Water Systems Provision Regulatory Account and the Arrow Water Systems Regulatory

Account. The Arrow Water Systems Regulatory Account is discussed further in section 7.8.5.

BC Hydro is required under the accounting standards to record a loss provision liability in regards to the divestiture of the Arrow Water Systems. The recording of the loss provision liability and the corresponding Arrow Water Systems Provision regulatory asset preserve BC Hydro's ability to seek recovery of actual costs in rates. As payments are made the provision account is drawn down and corresponding amounts are transferred to the Arrow Water Systems Regulatory Account and amortized into rates. The balance in the Arrow Water Systems Provision Regulatory Account represents BC Hydro's obligation to pay the water fees of the regions qualifying residents until such time that those residents are no longer on title for their properties.

BC Hydro is not requesting any changes to this account in this application.

7.8.20 IFRS Property, Plant and Equipment Regulatory Account

The IFRS Property, Plant and Equipment Regulatory Account enables the deferral of overhead costs that can no longer be capitalized under IFRS, as they are not directly attributable to the construction of an asset. Under CGAAP, costs related to administration and general overhead were eligible for capitalization to Property, Plant, and Equipment.

BCUC Order No. G-77-12A to BC Hydro's Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application implemented BC Hydro's proposal that overhead costs that can no longer be capitalized be deferred and transitioned into operating expenditures over ten years to avoid immediate and significant rate impacts. BCUC Order No. G-77-12A implemented this proposal and set the amortization period at 40 years, starting in fiscal 2013.

In the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application, BC Hydro included a proposal to transition the overhead costs that could no longer be capitalized under IFRS into rates over a ten-year period. Under this proposal 100 per cent of ineligible overhead costs were charged to the IFRS Property, Plant and Equipment Regulatory Account in fiscal 2012. Starting in fiscal 2013, the percentage of the ineligible overhead costs to be charged to the regulatory account was reduced by 10 per cent each year.

The actual and forecast annual additions and amortization for the IFRS Property, Plant and Equipment Regulatory Account are set out in Table 7-7 below. As indicated in the table and consistent with BC Hydro's proposal, additions to the account are forecast to be zero by fiscal 2022.

Table 7-7 IFRS Property, Plant and Equipment Regulatory Account

($ million)	Additions	Amortization
Fiscal 2012 Actual	221.8	-
Fiscal 2013 Actual	229.6	4.7
Fiscal 2014 Actual	179.5	8.7
Fiscal 2015 Actual	156.8	15.9
Fiscal 2016 Actual	134.4	19.8
Fiscal 2017 Actual	112.0	23.2
Fiscal 2018 Actual	89.6	26.0
Fiscal 2019 Forecast	67.2	28.2
Fiscal 2020 Plan	44.8	29.9
Fiscal 2021 Plan	22.4	31.0
Fiscal 2022 Plan	0.0	31.6

In the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application, BC Hydro also proposed to amortize the additions to the IFRS Property, Plant and Equipment Regulatory Account over 40 years. This amortization period was based on the composite life of BC Hydro's assets so that the overhead costs would be matched with the benefits of the underlying assets.

If BC Hydro had recognized the impact of the transition to IFRS in rates at the time of the transition, the rate impact for customers would have been immediate and significant. Amortizing these costs over a 40-year period allows these costs to be recovered over a similar period of time as was required under CGAAP, the accounting rules that BC Hydro followed prior to IFRS. Accordingly, a 40-year amortization period also results in approximately the same revenue requirement impact under IFRS as under the previous CGAAP rules. This means that ratepayers are not subject to higher rates as a result of changes in accounting standards. BC Hydro believes that the existing amortization period of 40 years continues to be appropriate.

BC Hydro is not requesting any changes to this account in this application.

7.8.21 IFRS Pension Regulatory Account

Upon the transition to IFRS in fiscal 2013, BC Hydro was required to recognize all unamortized actuarial gains and losses on the pension and other post-employment benefit plans, not previously recognized in its financial statements.

In the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application, BC Hydro requested the establishment of the IFRS Pension Regulatory Account with an opening liability balance equal to the actual unamortized actuarial gains and losses on the pension and other post-employment benefit plans, which BC Hydro had to recognize in its financial statements at the time of conversion to IFRS. BCUC Order No. G-77-12A implemented this request and also set the amortization period at 20 years on a straight-line basis, starting in fiscal 2013.

Amortizing these costs over a 20-year period results in approximately the same revenue requirement impact under IFRS as under the previous CGAAP rules. This means that ratepayers are not subject to higher rates as a result of changes in accounting standards. BC Hydro believes that the existing amortization period of 20 years continues to be appropriate.

BC Hydro is not requesting any changes to this account in this application.

7.9 Application of Interest to Regulatory Accounts

This section explains that it is generally appropriate for regulatory account balances to attract interest at BC Hydro's weighted average cost of debt in recognition that BC Hydro incurs carrying costs.

7.9.1 Rationale for Application of Interest Charge to Regulatory Account Balances

BC Hydro applies the principle of matching costs with benefits to determine whether interest should be applied to a regulatory account balance. This reflects the fact that the carrying costs of maintaining the account balances may have a real financial cost in any particular period that should be recovered in rates. For cash variance regulatory accounts that arise from a direct cash outlay by BC Hydro, the related interest costs are generally included as part of the regulatory accounts. BC Hydro incurs financing charges to carry amounts that were paid in cash but not recovered in rates in the same test period. For some accounts, the interest cost may be immediately expensed from the regulatory account to rates, rather than being deferred and amortized for recovery in future rates.

Variance regulatory accounts such as energy deferral accounts also attract interest because BC Hydro does not forecast variances in the accounts and therefore must fund the variances. In the case of lower than forecast revenues, BC Hydro incurs debt which results in finance charges.

Interest applied to regulatory accounts does not have the effect of increasing or decreasing BC Hydro's allowed net income, as the interest added to regulatory accounts is intended to offset the unbudgeted incremental interest costs that BC Hydro has incurred.

Based on this criteria, BC Hydro applies interest to all regulatory accounts, with the exception of the following accounts:

(a) Non-cash regulatory accounts (such as provisions);

(b) Rate-smoothing regulatory accounts (since the annual transfers to a rate-smoothing regulatory account already reflect the impact of the account on finance charges);

(c) The Total Finance Charges Regulatory Account (since interest costs are part of total finance charges); and

(d) Regulatory accounts that capture timing differences (such as Pre-1996 Contributions).

In addition, interest is not charged to the DSM Regulatory Account, similar to the treatment for capital projects, as DSM expenditures generally go into service in the year of expenditure and BC Hydro does not apply interest on capital projects after they enter service. Lastly, interest is not charged to the Customer Crisis Fund Regulatory Account due to the short-term duration of the pilot program. Table 7-8, below indicates which deferral and regulatory accounts have interest applied to balances.

Table 7-8 Application of Interest to Regulatory Accounts

Regulatory Account	Interest Applied to Balance
Cost of Energy Variance Accounts	
Heritage Deferral Account	Yes
Non Heritage Deferral Account	Yes
Trade Income Deferral Account	Yes
Other Cash Variance Accounts	
Storm Restoration Costs Regulatory Account	Yes
Amortization of Capital Additions Regulatory Account	Yes
Total Finance Charges Regulatory Account	No
Rock Bay Remediation Regulatory Account	Yes
Arrow Water Systems Regulatory Account	Yes
Remediation Regulatory Account	Yes
Real Property Sales Regulatory Account	Yes
Mining Customer Payment Plan Regulatory Account	Yes
Dismantling Cost Regulatory Account	Yes
Customer Crisis Fund Regulatory Account	No
Non-Cash Variance Accounts	
Foreign Exchange Gains and Losses Regulatory Account	No
Non-Current Pension Costs Regulatory Account	No
Debt Management Regulatory Account	No
PEB Current Pension Costs Regulatory Account	No
Benefit Matching Accounts	
DSM Regulatory Account	No
First Nations Costs Regulatory Account	Yes
Site C Regulatory Account	Yes
Pre-1996 Contributions in Aid of Construction Regulatory Account	No
Capital Project Investigation Costs Regulatory Account	No
SMI Regulatory Account	Yes
Non-Cash Provisions	
First Nations Provisions Regulatory Account	No
Environmental Provisions Regulatory Account	No
Arrow Water Systems Provisions Regulatory Account	No
IFRS Transition Accounts	
IFRS Property, Plant and Equipment Regulatory Account	No
IFRS Pension Regulatory Account	No

7.9.2 Interest Rate Applied to Regulatory Accounts

By Order No. G-77-12A to BC Hydro's Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application, the BCUC approved that the interest rate applicable to BC Hydro's regulatory account balances in a given year is the weighted average cost of debt in that year. The weighted average cost of debt that is forecast to be applied to the regulatory account balances is 3.88 per cent for fiscal 2020 and 3.82 per cent for fiscal 2021.

7.10 Summary of BC Hydro's Regulatory Accounts and Approach to Recovery

Table 7-9 below provides a summary of the information contained in this chapter for each of BC Hydro's regulatory accounts.

Table 7-9 Summary of BC Hydro's Regulatory Accounts

($ million)		F2019 Forecast	F2021 Forecast	Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate	Accounts to Potentially be Closed by Fiscal 2024
Cost of Energy Variance Accounts							
1	Heritage Deferral Account	(388)	0	Captures variances related to BC Hydro's Heritage Cost of Energy as well as other items approved by the BCUC.	Net Forecast Cost of Energy Variance Account balance is proposed to be refunded to ratepayers during the test period	Credit balance should be refunded to ratepayers over the test period to reduce rate increases. BC Hydro expects to propose utilizing the DARR table mechanism for future balances	
2	Non-Heritage Deferral Account	120	(0)	Captures variances related to BC Hydro's Non-Heritage Cost of Energy (i.e., IPPs) and revenue variances related to Customer Load as well as other items approved by the BCUC.	Net Forecast Cost of Energy Variance Account balance is proposed to be refunded to ratepayers during the test period	Credit balance should be refunded to ratepayers over the test period to reduce rate increases. BC Hydro expects to propose utilizing the DARR table mechanism for future balances.	
3	Trade Income Deferral Account	(24)	(0)	Captures variances between forecast and actual Trade Income (i.e., Powerex)	Net Forecast Cost of Energy Variance Account balance is proposed to be refunded to ratepayers during the test period	Credit balance should be refunded to ratepayers over the test period to reduce rate increases. BC Hydro expects to propose utilizing the DARR table mechanism for future balances.	
	Sub-Total	(293)	(0)				

($ million)		F2019 Forecast	F2021 Forecast	Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate	Accounts to Potentially be Closed by Fiscal 2024
Other Cash Variance Accounts							
4	Storm Restoration Costs	38	0	Captures variances between forecast and actual storm restoration costs.	Next Test Period	These expenditures provide immediate, rather than long-term benefits and therefore should be recovered over a shorter period of time.	
5	Amortization of Capital Additions	20	0	Captures variances between forecast and actual amortization of capital additions.	Next Test Period	These expenditures provide immediate, rather than long-term benefits and therefore should be recovered over a shorter period of time.	
6	Total Finance Charges	(9)	0	Captures variances between forecast and actual finance charges	Next Test Period	These expenditures provide immediate, rather than long-term benefits and therefore should be recovered over a shorter period of time.	
7	Rock Bay Remediation	(21)	(0)	Captures expenditures incurred related to the remediation of the Rock Bay property.	Next Test Period	These expenditures provide immediate, rather than long-term benefits and therefore should be recovered over a shorter period of time.	To be closed in fiscal 2023

($ million)		F2019 Forecast	F2021 Forecast	Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate	Accounts to Potentially be Closed by Fiscal 2024
8	Arrow Water Systems	0	0	Captures costs related to BC Hydro's divestiture of the Arrow Water Systems (drinking water systems) built by BC Hydro during the construction of the Hugh Keenleyside Dam.	As Expenditures are Incurred	These expenditures provide immediate, rather than long-term benefits and therefore should be recovered over a shorter period of time.	Will propose closure in fiscal 2022
9	Remediation	(25)	0	Captures variances between forecast and actual costs incurred related to compliance with Polychlorinated Biphenyl Regulations (PCB) and Asbestos remediation at BC Hydro facilities.	Next Test Period	These expenditures provide immediate, rather than long-term benefits and therefore should be recovered over a shorter period of time.	
10	Real Property Sales	44	31	Captures variances between forecast and actual gain/loss on real estate sales.	Self-clearing (to fiscal 2024)	Smoothes the recognition of gains and losses as sales will not occur uniformly over the 10 years since fiscal 2015	May be closed by fiscal 2024
11	Dismantling Cost	51	0	Captures variances between forecast and actual Dismantling Costs.	Next Test Period	These expenditures provide immediate, rather than long-term benefits and therefore should be recovered over a shorter period of time.	

($ million)		F2019 Forecast	F2021 Forecast	Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate	Accounts to Potentially be Closed by Fiscal 2024
12	Customer Crisis Fund	0	(0)	Captures the net difference between Customer Crisis Fund Rate Rider revenues and BC Hydro's incremental costs related to the Customer Crisis Fund pilot program.	N/A	If necessary, BC Hydro will request a recovery mechanism upon completion of the three year pilot program.	May be closed by fiscal 2024
13	Mining Customer Payment Plan	0	0	Captures any amounts impaired related to mining customers participating in the Mining Customer Payment Plan Program.	N/A	$0 Balance Currently. If necessary, BC Hydro will request a recovery mechanism upon completion of the Program.	May be closed by fiscal 2024
	Sub-Total	99	31				
Non-Cash Variance Accounts							
14	Foreign Exchange Gains/Losses	7	5	Captures foreign exchange gains and losses on the translation of foreign denominated long-term monetary items.	Straight-line Pool Method	The recovery period matches the underlying attribute and should be recovered over a longer period of time (i.e., foreign denominated long-term monetary items).	

($ million)		F2019 Forecast	F2021 Forecast	Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate	Accounts to Potentially be Closed by Fiscal 2024
15	Non-Current Pension Costs	(3)	(35)	Captures variances between forecast and actual non-current pension costs.	Over Average Remaining Service Life of Active Employee Group (EARSL) - currently 12 years	The recovery period matches the underlying attribute and should be recovered over a longer period of time (i.e., remaining life of employee group).	
16	PEB Current Pension Costs	(2)	0	Captures operating cost variances between forecast and actual current pension costs.	Next Test Period	These expenditures provide immediate, rather than long-term benefits (i.e., current pension costs).	
17	Debt Management	(260)	(235)	Captures mark-to-market gains and losses on financial contracts that hedge future long-term debt.	Over remaining term of associated long-term debt issuances	The recovery period matches the underlying attribute (i.e., long-term debt Issuance).	
	Sub-Total	(258)	(265)				
Benefit Matching Accounts							
18	DSM	927	950	Captures expenditures associated with Demand-Side Management activities. These expenditures result in future energy savings.	Over 15 years	Matches the future benefit period for customers, which is the average measure life of DSM initiatives.	

($ million)		F2019 Forecast	F2021 Forecast	Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate	Accounts to Potentially be Closed by Fiscal 2024
19	First Nations Costs	85	56	Captures First Nations annual and lump sum settlement payments and negotiation costs.	Over 10 years for lump sum settlement payments	Lump sum settlements are amortized over a longer period of time than annual settlement payments, which are amortized each year.	
20	Site C	491	526	Captures costs related to the Site C project prior to the final investment decision to proceed with the project, and costs that are not eligible for capitalization thereafter.	N/A	BC Hydro will request a recovery mechanism once the Site C Project is in-service.	
21	Pre-1996 Contributions in Aid of Construction	83	73	Captures the difference between the 25-year amortization period required for regulatory purposes and the 45-year amortization period required for financial reporting for this asset class.	Over 45 years (to fiscal 2040)	Matches the 45-year amortization period determined in a depreciation study filed in the Fiscal 2007 - Fiscal 2008 Revenue Requirements Application.	

($ million)		F2019 Forecast	F2021 Forecast	Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate	Accounts to Potentially be Closed by Fiscal 2024
22	Capital Project Investigation Costs	10	0	Captured capital project investigation costs over fiscal 2009 to fiscal 2011. No further additions are being made to this account.	Over 10 years (to fiscal 2021)	Will be fully amortized and closed in fiscal 2021	To be closed in fiscal 2021
23	SMI	217	174	Captured operating costs related to the SMI Program. The SMI Program is complete and no further additions are being made to this account.	Over 15 years (to fiscal 2029)	Matches the future benefit period for customers, which is the average life of the SMI assets.	
	Sub-Total	1,814	1,778				

($ million)		F2019 Forecast	F2021 Forecast	Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate	Accounts to Potentially be Closed by Fiscal 2024
Non-Cash Provisions							
24	First Nations Provisions	420	428	Regulatory provision established for BC Hydro's liability in respect of First Nations claims.	Amounts recovered in First Nations Costs Regulatory Account as settlement payments are made	Since non-cash provisions are not recovered in rates, no recovery mechanism is required. The provision is drawn down when actual expenditures are charged to the regulatory account and the amounts are recovered from the corresponding expenditure regulatory account (i.e., First Nations Costs Regulatory Account).	
25	Environmental Provisions	276	194	Regulatory provision established for BC Hydro's liability in respect of compliance with Polychlorinated Biphenyl Regulations, remediation of environmental contamination at Rock Bay and asbestos remediation at BC Hydro facilities.	Amounts recovered in Remediation and Rock Bay Regulatory Accounts as expenditures are incurred	Since non-cash provisions are not recovered in rates, no recovery mechanism is required. The provision is drawn down when actual expenditures are charged to the regulatory account and the amounts are recovered from the corresponding expenditure regulatory account (i.e., Remediation Regulatory Account (PCB and Asbestos) and the Rock Bay Remediation Regulatory Account).	

($ million)		F2019 Forecast	F2021 Forecast	Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate	Accounts to Potentially be Closed by Fiscal 2024
26	Arrow Water Systems Provision	3	2	Regulatory provision established for BC Hydro's liability in respect of the divestiture of the Arrow Water Systems (drinking water systems) to the Regional District of Central Kootenay.	Amounts recovered in Arrow Water Systems Regulatory Account as expenditures are incurred	Since non-cash provisions are not recovered in rates, no recovery mechanism is required. The provision is drawn down when actual expenditures are charged to the regulatory account and the amounts are recovered from the corresponding expenditure regulatory account (i.e., Arrow Water Systems Regulatory Account).	Will propose closure in fiscal 2022
	Sub-Total	699	624				
Rate Smoothing Accounts							
27	Rate Smoothing	0	0	Captured portions of the allowed revenue requirement that were not recovered in rates in that particular fiscal year.	N/A	Balance in account written-off in December 2018.	To be closed in Fiscal 2020
	Sub-Total	0	0				

($ million)		F2019 Forecast	F2021 Forecast	Description of Account	Approved/ Proposed Recovery Mechanism	Why is the Recovery Mechanism Appropriate	Accounts to Potentially be Closed by Fiscal 2024
IFRS Transition Accounts							
28	IFRS Property, Plant and Equipment	1,064	1,071	Captures capital overhead costs that were eligible for capitalization under CGAAP, but can no longer be capitalized under IFRS.	Rolling 40 year period (to fiscal 2061)	Recovered on the same basis as under the previous CGAAP accounting rules. Therefore ratepayers are not impacted by higher rates as a result of changes in accounting standards.	
29	IFRS Pension	497	421	Captures unamortized gains/losses on BC Hydro's pension plans that were required to be recognized in BC Hydro's financial statements upon transition to IFRS.	Over 20 years (to fiscal 2032)	Recovered on the same basis as under the previous CGAAP accounting rules. Therefore ratepayers are not impacted by higher rates as a result of changes in accounting standards.	
	Sub-Total	1,561	1,491				
	Total	**3,622**	**3,658**				

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Fiscal 2020 to Fiscal 2021
Revenue Requirement Application

Chapter 8

Other Revenue Requirements Items

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8.1 Other Revenue Requirements Items

This chapter describes the other revenue requirements items, including amortization expense, return on equity, capital structure, finance charges, taxes, miscellaneous and inter-segment revenues, subsidiary net income, the allocation of BC Hydro's business support costs, and provisions and other. This chapter also explains accounting changes required due to the full adoption of the International Financial Reporting Standards **(IFRS)** in fiscal 2019.

8.2 Amortization Expense

Depreciation and amortization is the allocation of the original cost of assets over their estimated service lives. BC Hydro's forecast amortization expense is shown in Appendix A, Schedule 7.0, and includes:

- The amortization of property, plant and equipment in service;
- Amortization related to agreements that are recognized as leases under the new IFRS 16, *Leases* standard, which is discussed in sections 8.12.1 and 8.13.3;
- Amortization of the following regulatory accounts:
  - DSM Regulatory Account;
  - Pre-1996 Contributions in Aid of Construction Regulatory Account; and
  - Amortization of Capital Additions Regulatory Account.

Amortization expense is summarized in Table 8-1 below. Amortization expense is forecast to increase by $105 million from $955 million in the fiscal 2019 RRA Plan to $1.06 billion in fiscal 2021, primarily due to the following:

- An increase of approximately $75 million in amortization related to higher forecast capital additions, as described in Chapter 6;

- An increase of approximately $14 million as a result of higher amortization of the Amortization of Capital Additions Regulatory Account, mainly due to the deferral in fiscal 2019 of amortization related to BC Hydro’s purchase of the remaining two-thirds interest in the Waneta Dam; and
- An increase of approximately $11 million in amortization related to agreements that are recognized as leases under the new IFRS 16, *Leases* standard.

Table 8-1 Amortization Expense

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Amortization of Capital Assets	7.0 L5	757.5	755.5	791.7	792.2	828.0	848.6	882.1	902.8
2	Dismantling Costs	7.0 L10	8.6	8.7	0.0	0.0	0.0	0.0	0.0	0.0
3	IPP Leases	7.0 L12+L14	17.0	13.7	29.4	15.4	22.8	22.8	30.2	30.2
4	Other Leases	7.0 L13	0.0	0.0	0.0	0.0	0.0	0.0	3.4	3.4
5	Total Gross Amortization	7.0 L16	783.2	777.9	821.1	807.6	850.9	871.5	915.7	936.5
6	Transfer to NHDA	7.0 L14	0.0	3.3	0.0	14.0	0.0	0.0	0.0	0.0
7	Regulatory Account Transfers	7.0 L18	0.0	2.0	0.0	(0.7)	0.0	(21.8)	0.0	0.0
8	Total Transfer to Deferral & Regulatory		0.0	5.3	0.0	13.3	0.0	(21.8)	0.0	0.0
	Regulatory Account Recoveries									
9	DSM Amortization	7.0 L22	89.1	89.1	96.7	95.6	102.8	99.6	104.2	108.3
10	FRSR Amortization	7.0 L27	(8.6)	(8.7)	0.0	0.0	0.0	0.0	0.0	0.0
11	Pre-1996 CIAC Amortization	7.0 L28	0.7	0.7	3.2	3.2	4.9	4.9	5.1	5.1
12	Capital Additions Regulatory Account	7.0 L30	(3.6)	(3.6)	(3.4)	(3.4)	(3.3)	(3.3)	10.7	10.3
13	Regulatory Account Recoveries	7.0 L31	77.6	77.5	96.5	95.4	104.4	101.2	119.9	123.7
14	Total Current Amortization	7.0 L32	860.7	860.7	917.5	916.3	955.3	950.8	1,035.6	1,060.2

Property, plant and equipment in service are amortized on an individual component-by-component basis over the expected useful lives of the assets using the straight-line method, under which amortization expense is recognized evenly over the expected useful life of an asset. The depreciation rates used in this Application are the same as those previously approved by the BCUC, with the exception of certain property, plant and equipment at the Burrard synchronous condense facility, and the following new asset classes:

- Water Rights;
- Infrastructure Rights; and
- LED Streetlights.

In addition, new asset classes will be created as a result of the adoption of the new IFRS 16, *Leases* standard in fiscal 2020. These leases will be amortized over the lease term in accordance with IFRS 16, which will depend on the terms of the agreement.

8.2.1 Burrard Synchronous Condense Facility Depreciation Rates

The BCUC reviewed and approved the depreciation rates related to certain property, plant and equipment at the Burrard synchronous condense facility for fiscal 2017, fiscal 2018 and fiscal 2019 in the Previous Application proceeding. In this Application, BC Hydro is seeking approval for the depreciation rates of certain property, plant and equipment at the Burrard synchronous condense facility for fiscal 2020 and fiscal 2021. Table 8-2 provides the detailed depreciation rates for the Burrard synchronous condense facility for each year of the test period for which BC Hydro is seeking BCUC approval. The depreciation rates shown in Table 8-2 for a given fiscal year are applied against the net book value of the asset at the beginning of that fiscal year. The methodology used to determine the depreciation rates for fiscal 2020 and fiscal 2021 is consistent with the methodology underlying the depreciation rates approved by the BCUC in its Decision on the Previous Application.

Table 8-2 Burrard Synchronous Condense Facility Depreciation Rates

Class of Property, Plant and Equipment		F2020 Depreciation Rate (%/year)	F2021 Depreciation Rate (%/year)
C12002	Road, Paved/Gravel	100.0	-
C12203	Bridge, Concrete	16.7	20.0
C12401	Drainage System, Yard	16.7	20.0
C21901	Roofs	16.7	20.0
C22001	Plant, Concrete Or Steel	16.7	20.0
C22002	Commercial, Concrete Or Steel	16.7	20.0
C22005	Building, Composite Pool	16.7	20.0
C22006	Equipment Shelter	100.0	-
C22009	Buildings-HVAC Systems & Components	16.7	20.0
C22101	Office Trailer/Mobile Home	16.7	20.0
C23801	Cranes	16.7	20.0
C25101	Structure, Support, Steel	16.7	20.0
C25301	Foundations	16.7	20.0
C25401	Ducts & Trenches	16.7	20.0
C30102	Insulation, Boiler	16.7	20.0
C30501	Piping, High Pressure	28.3	20.0
C30607	DNU - Asbestos Abatement	16.7	20.0
C30802	Water Deluge System, Ammonia	16.7	20.0
C31001	Water Intake/Discharge Struct	16.7	20.0
C31002	Protection, Cathodic	16.7	20.0
C34004	Turbine, Composite Pool	16.7	20.0
C34005	Coils, Stator	16.7	20.0
C34006	Rotor, Generator	16.7	20.0
C34007	Generator, Composite Pool	16.7	20.0
C34009	Cooling System, Hydrogen	32.9	22.0
C42004	Major Maintenance - Rewedging	16.7	20.0
C42102	Exciter, Static	16.7	20.0
C48003	Generator, Composite Pool	16.7	20.0
C48004	Generator, Diesel	16.7	20.0
C49001	Pump	45.0	20.0
C49002	Motor	16.7	20.0
C51001	Condensor, Synchronous,Rotary	16.7	20.0
C52105	Transformer, Station Service	16.7	20.0

	Class of Property, Plant and Equipment		F2020 Depreciation Rate (%/year)	F2021 Depreciation Rate (%/year)
34	C52504	Transformer, Voltage,Encaps.	16.7	20.0
35	C54101	Breaker, Air/Magnetic	16.7	20.0
36	C55401	Buswork & Station Conductor	16.7	20.0
37	C55501	Grounding Systems	16.7	20.0
38	C56001	Insulators	16.7	20.0
39	C59001	Power Supply, Uninterruptible	16.7	20.0
40	C59101	Regulator, Feeder Circuit	16.7	20.0
41	C59201	Charger System, Battery	16.7	20.0
42	C61001	Fencing	16.7	20.0
43	C62001	Fire Protection System	93.3	20.0
44	C65001	Panels/Cubicles, P&C	16.7	20.0
45	C67003	Containment Facility, Concrete	16.7	20.0
46	C67005	Oil Spill Containment	16.7	20.0
47	C68204	Distributed Control System	16.7	20.0
48	C68301	Radio,Microwave, Analog	16.7	20.0
49	C70104	Instrumentation - Digital	16.7	20.0
50	C75104	Compressor, Air	16.7	20.0
51	C75201	Tanks, Steel, Air/Fuel	16.7	20.0
52	C75301	Water Supply System	36.5	20.0
53	C82504	Loader / Backhoe	16.7	20.0
54	C82550	Tools/Work Equipment, Misc	19.6	20.5
55	C82551	DNU - Tools/Work Equipment, Misc	21.5	20.0
56	C82603	Manufacturing/Test Equipment	16.7	20.0

8.2.2 New Asset Classes and Depreciation Rates

Table 8-3 provides the expected useful life and depreciation rates for new asset classes for which BC Hydro is seeking approval in this Application. The new asset classes are required for new assets that are not within the scope of existing asset classes. The asset class numbers, names, expected useful lives, and the resulting depreciation rates are provided in the table below.

Table 8-3 New Asset Classes Expected Useful Life and Depreciation Rates

Class of Property, Plant and Equipment or Intangible Asset	Expected Useful Life (Years)	Depreciation Rate (%/year)
C11640 Water Rights (finite)	40	2.5
C11650 Infrastructure Rights	35	2.9
C59503 LED Streetlights	20	5.0

Water Rights (finite)

The majority of BC Hydro's water licenses were issued in perpetuity; however, a small number (approximately 20 to 25) of licenses have a finite term of 40 years. The term of some of these licences is expiring and BC Hydro will incur costs to obtain new licences. The costs associated with the original water licences were included in the cost of the generating facility property, plant and equipment because the costs were not separately identifiable from the other approval costs of the generating facility.

The costs directly attributable to the renewal of finite term water licenses are appropriate to capitalize because the water licenses meet the recognition criteria for intangible assets. The finite term water license intangible assets will be amortized over the 40-year term of each license. A new asset class for renewal costs associated with finite term water licenses is being established because an existing asset class does not exist for these separately identifiable intangible assets.

Infrastructure Rights

BC Hydro is undertaking voltage conversion projects in certain areas of the distribution system. In order to realize the economic benefits of the system upgrade, BC Hydro must be able to connect the system to the customer's electrical infrastructure. Due to space limitations in certain areas, the transformer and the switchgear are located in the customer premises and are owned and operated by the customer. Therefore, the customer-owned equipment must be upgraded to enable the customer to receive the electricity at the new, higher voltage. BC Hydro incurs the costs to connect the customer to the system in order to realize the benefits of the system upgrade.

The costs incurred by BC Hydro represent a contribution to the customer. The contributions are eligible for capitalization as they meet the criteria for recognizing intangible assets. BC Hydro has not incurred such costs in the past; therefore, an asset class did not exist. A new asset class named Infrastructure Rights has been established with a 35-year useful life that is representative of the benefit period for the intangible asset based on the approximate life of the underlying assets.

LED Street Lights

BC Hydro-owned street light assets currently have high-pressure sodium (**HPS**) lights (luminaires). BC Hydro will be replacing the HPS luminaires with LED units in future years. Currently, the street lights (including the luminaires) are included in one asset class and the cost of replacing luminaries is expensed. The luminaire is essentially a light bulb which is low cost and has a short life. The cost of the LED unit is much higher than the cost of a luminaire and the life of the LED unit is significantly longer, estimated at 20 years. As the LED unit is a significant part of the street light, a new component asset class with a 20-year life is being established.

Forecast capital additions over fiscal 2019 to fiscal 2021 for each asset class are provided below in Table 8-4 below.

Table 8-4 New Asset Classes Forecast Capital Additions

($ million)	F2019 Forecast	F2020 Plan	F2021 Plan
C11640 Water Rights (finite)	-	-	5.3
C11650 Infrastructure Rights	5.7	20.5	12.8
C59503 LED Streetlights	-	3.8	5.8
Total	**5.7**	**24.3**	**23.9**

8.2.3 New Asset Classes – Leases

New asset classes will be created as a result of the adoption of the new IFRS 16, *Leases* standard in fiscal 2020. These leases will be recognized as assets and amortized over the lease term in accordance with IFRS 16, which will depend on the terms of the agreement. In this Application, BC Hydro is seeking approval to amortize the assets within these three new asset classes over the lease term in accordance with IFRS 16.

Further information on IFRS 16, *Leases* can be found in section 8.12.1 and 8.13.3.

Table 8-5 New Asset Classes, IFRS 16 *Leases* Expected Useful Life and Depreciation Rates

Class of Property, Plant and Equipment or Intangible Asset	Expected Useful Life (Years)	Depreciation Rate (%/year)
C95010 ROU - Land and buildings	Over the Lease Term	Varies for each agreement
C95020 ROU - Generation Assets	Over the Lease Term	Varies for each agreement
C95030 ROU - Miscellaneous	Over the Lease Term	Varies for each agreement

8.3 Return on Equity

BC Hydro's return on equity is prescribed by section 3 of Direction No. 8 as a specific dollar amount of $712 million per fiscal year in each of fiscal 2020 and fiscal 2021. Specifically, Direction No. 8 requires that the BCUC must allow BC Hydro to collect sufficient revenue in each fiscal year to achieve an annual rate of return on deemed equity to yield a distributable surplus of $712 million for fiscal 2020 and fiscal 2021. This dollar amount is consistent with the dollar amount of BC Hydro's allowed return on equity for fiscal 2019.

For fiscal 2022 onwards, the BCUC will be able to determine BC Hydro's Return on Equity. In the Comprehensive Review Report, the Government of B.C. indicated that it may provide policy guidance to the BCUC to inform this process.

The calculation of the BC Hydro's return on equity for the test period is set out in Appendix A, Schedule 9, and is an allowed return on equity percentage of 10.32 per cent in fiscal 2020 and 10.14 per cent in fiscal 2021.

8.4 Capital Structure

BC Hydro's capital structure is prescribed by Direction No. 8.

Pursuant to the definition of "deemed equity" in section 1 of Direction No. 8, BC Hydro's equity is deemed to be 30 per cent of rate base, which is also defined in section 1 of Direction No. 8.

As noted in section 8.3, BC Hydro's return on equity for fiscal 2020 and fiscal 2021 is a specific dollar amount of $712 million per fiscal year, and as a result BC Hydro's return on equity as a specific dollar amount is no longer linked to changes in deemed equity, and therefore rate base.

BC Hydro's dividend payment to the Province is prescribed by Heritage Special Directive No. HC1. Pursuant to Order in Council No. 095 issued on March 14, 2014, for fiscal 2018 and subsequent years, the payment to the Province will be reduced by $100 million per year based on the payment in the immediate preceding fiscal year until it reaches zero and will thereafter remain at zero until BC Hydro achieves a 60:40 debt to equity ratio. As shown on Appendix A, Schedule 9, line 3, BC Hydro's forecast dividend payment to the Province for fiscal 2019 is $59 million and is zero for each of fiscal 2020 and fiscal 2021. BC Hydro's forecast debt to equity ratio for fiscal 2020 and fiscal 2021 is shown on Appendix A, Schedule 9, lines 18 and 19.

8.5 Finance Charges

Finance charges are primarily comprised of interest charges on BC Hydro's debt. In addition, finance charges include interest related to leases recognized as lease obligations under IFRS 16, *Leases* as described in section 8.13.3 and non-current pension costs as described in Chapter 5G, section 5G.9. Total finance charges are calculated net of sinking fund income, finance charges capitalized to unfinished construction (interest during construction) and interest applied to regulatory accounts.

BC Hydro's long-term debt is comprised of bonds and revolving borrowings obtained under agreement with the Government of B.C. BC Hydro's debt is either held or guaranteed by the Government of B.C.

BC Hydro uses financial instruments, principally interest rate and foreign currency swaps, to manage interest rate and foreign exchange risks related to existing debt and forecast future debt issuances.

Since fiscal 2017, BC Hydro has locked in interest rates on forecast future long-term debt issuances by entering into financial contracts that hedge the interest rate risk. In accordance with BCUC Order No. G-42-16, mark-to-market gains and losses related to interest rate hedges of future debt are captured in the Debt Management Regulatory Account and are amortized over the term of the associated long-term debt issuances as shown on Appendix A, Schedule 2.2. Further information regarding the Debt Management Regulatory Account can be found in Chapter 7 section 7.8.13.

To forecast finance charges, BC Hydro uses a number of market variables and economic forecasts of short and long-term interest rates and foreign exchange rates. For debt that will be issued in the future and has already been hedged, BC Hydro uses the hedged rate in the forecast. The weighted average forecast hedged interest rate is 3.40 per cent for fiscal 2020 and 3.45 per cent for fiscal 2021.

For debt that will be issued in the future that is unhedged, BC Hydro uses economic forecasts that are developed and provided by the Treasury Board of the Government of B.C. The following table shows the forecast interest rates for unhedged debt and the forecast foreign exchange rate for fiscal 2020 to fiscal 2021.

Table 8-6 Forecast Interest Rates and Forecast Foreign Exchange Rate

	F2020 Plan	F2021 Plan
Canadian Short-term Interest Rate (%)	2.37	2.59
U.S. Short-term Interest Rate (%)	3.12	3.25
Canadian Long-term Interest Rate (%)	3.50	3.86
U.S. Long-term Interest Rate (%)	3.92	4.02
USD$/CAD$ Exchange Rate	0.7910	0.7973

Source: Treasury Board Forecast, October 2018.

Foreign currency-denominated monetary assets and liabilities are translated into Canadian dollars at the rate of exchange prevailing at the balance sheet date.

As shown on Appendix A, Schedule 2.2, gains and losses arising from the translation of unhedged foreign denominated long-term monetary items are included in the Foreign Exchange Gains and Losses Regulatory Account and are amortized on a straight-line pool basis in accordance with BCUC Order No. G-47-02. Further information regarding the Foreign Exchange Gains and Losses Regulatory Account can be found in Chapter 7, section 7.8.10.

As shown on Appendix A, Schedule 2.2, variances between forecast and actual non-current pension costs are deferred to the Non-Current Pension Costs Regulatory Account in accordance with BCUC Order No. G-48-14 and are amortized over the expected average remaining service life of the active plan members. Further information regarding the Non-Current Pension Costs Regulatory Account can be found in Chapter 7, section 7.8.11.

Forecast finance charges are shown on Appendix A, Schedule 8.0 and are summarized in Table 8-7 below.

Current finance charges are forecast to increase from $556 million in the fiscal 2019 RRA Plan to $662 million in fiscal 2021. The principal drivers of the net $107 million increase in finance charges are:

- A decrease of $123 million in the recovery of the credit balances in regulatory accounts, primarily related to the Total Finance Charges Regulatory Account and the Foreign Exchange Gains and Losses Regulatory Account;
- An increase in forecast borrowing costs of approximately $60 million resulting from the forecast increase in BC Hydro's debt over the test period largely driven by capital expenditures;

These increases are partially offset by:

- A forecast increase in interest during construction of approximately $88 million, which reduces finance charges.

Table 8-7 Finance Charges

($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
		1	2	3	4	5	6	7	8
Total Gross Finance Charges	8.0 L1	708.8	579.2	735.0	805.9	773.8	684.6	757.5	726.9
Total Finance Charge Reg. Acct Additions	8.0 L21	0.0	12.6	0.0	25.1	0.0	(28.8)	0.0	0.0
Other Regulatory Account Additions	.0 L3-L8+L2	(27.1)	162.4	(14.4)	(46.9)	(17.7)	78.8	(19.2)	(19.5)
Interest on Regulatory Accounts	8.0 L25	(75.8)	(75.3)	(68.3)	(61.6)	(60.1)	(38.6)	(24.3)	(27.6)
Regulatory Account Recoveries	8.0 L31	(101.3)	(174.9)	(139.9)	(209.4)	(140.5)	(140.4)	(16.6)	(17.6)
Total Current Finance Charges	8.0 L32	504.6	504.0	512.4	513.1	555.5	555.6	697.5	662.3

Since fiscal 2012, forecast interest during construction and the interest applied to regulatory accounts in a given year have both been based on BC Hydro's forecast weighted average cost of debt in that year.[333] As described in section 8.13.4, as a result of the adoption of IFRS 14, *Regulatory Deferral Accounts*, interest during construction cannot include the amortization of regulatory accounts. As a result,

[333] As required under IFRS International Accounting Standard 23 Borrowing Costs for the determination of capitalization of borrowing costs.

BC Hydro's forecast interest during construction will be based on a forecast weighted average cost of debt rate which excludes the amortization of the Debt Management Regulatory Account (referred to in this Application as the interest during construction rate). Forecast interest applied to BC Hydro's regulatory accounts will continue to be based on BC Hydro's forecast weighted average cost of debt including the amortization of the Debt Management Regulatory Account (referred to in this Application as the weighted average cost of debt rate).

8.6 Taxes

Taxes include school taxes and grants-in-lieu of general taxes.

The *Hydro and Power Authority Act* exempts BC Hydro from all property taxes other than those levied in respect of schools. School taxes are based on the assessed value of taxable assets as prepared by B.C. Assessment and tax rates that are established by the Province of British Columbia.

School taxes are paid on all assessable property except for BC Hydro's generation facilities on the Peace, Pend d'Oreille, and Columbia rivers.

The *Hydro and Power Authority Act* authorizes BC Hydro to pay grants-in-lieu of general municipal, regional district and local improvement taxes. Order in Council No. 266/2016 and Order in Council No. 533/2017 set out the formula used to calculate the grant payments. Annual grants paid include the following items:

- General grants equivalent to municipal, regional district and local improvement taxes on the assessed value of all land of BC Hydro and on the assessed value of improvements such as office buildings, field service buildings and substation control buildings. Assessed values of generating plants, substation equipment, transmission lines and distribution lines are excluded from this calculation;

- Revenue grants equal to 1 per cent of gross revenue from sales of electricity within the province, excluding revenue from power sold to other distribution systems for resale; and
- Special grants on dams, reservoirs and powerhouses. These grants are based on installed generating capacity, or imputed nameplate capacity in the case of storage dams.

Forecast school taxes and grants-in-lieu are shown on Appendix A, Schedule 6.0 and are summarized in the table below. Over the test period, taxes are forecast to increase compared to the fiscal 2019 RRA Plan primarily as a result of the following factors:

- Increased assessed property values for land, buildings, and electric system assets;
- The completion of new capital projects that are subject to taxation such as the John Hart Generating Station Replacement project;
- Increased forecast revenues from electricity sales for which 1 per cent is paid as a grant; and
- Increases to provincial and municipal taxation rates.

Table 8-8 Taxes

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Grants in Lieu	6.0 L16	93.6	93.6	97.5	97.7	102.6	105.3	110.8	114.8
2	School Taxes	6.0 L17	127.1	127.3	130.2	131.1	133.6	134.3	138.3	146.8
3	Other	6.0 L18+L19+L21	2.6	2.2	4.2	2.3	2.5	2.6	0.6	0.6
4	Total Gross Taxes	6.0 L22	223.3	223.1	231.8	231.1	238.7	242.2	249.8	262.2
5	Transfer to NHDA	6.0 L23	0.0	0.4	0.0	1.9	0.0	0.0	0.0	0.0
6	Total Current Taxes	6.0 L24	223.3	223.5	231.8	232.9	238.7	242.2	249.8	262.2

8.7 Miscellaneous Revenues

Miscellaneous revenues include revenues from amortization of contributions in aid of construction, lease and other revenues related to BC Hydro's purchase of the remaining two-thirds interest in the Waneta Dam from Teck Metals Ltd. (**the Waneta 2017 Transaction**), external transmission revenues under the Open Access Transmission Tariff, meter/transformer rentals and power factor surcharges, late payment charges, building rentals, interconnections, Customer Crisis Fund rate rider revenues, and other revenues.

Forecast Miscellaneous Revenues for the test period are shown on Appendix A, Schedule 15.0 and are summarized in the table below.

Over the test period, Miscellaneous revenues are expected to increase by approximately $103 million compared to the fiscal 2019 RRA plan primarily due to approximately $87 million of lease and other revenues related to BC Hydro's purchase of the remaining two-thirds interest in the Waneta Dam. Miscellaneous revenues related to the Waneta 2017 Transaction can be found on Appendix A, Schedule 15.0, lines 20 to 25.

Table 8-9 Miscellaneous Revenues

($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
		1	2	3	4	5	6	7	8
Total Gross Miscellaneous Revenue	15.0 L39	137.1	143.1	138.3	143.7	140.6	202.9	240.8	247.2
Transfers to NHDA	15.0 L40	0.0	0.0	0.0	0.0	0.0	(51.3)	(3.1)	(3.5)
Transfers to Regulatory Accounts	15.0 L41	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0
Total Current Miscellaneous Revenue	15.0 L42	137.1	143.4	138.3	143.7	140.6	151.6	237.7	243.7

8.8 Inter-Segment Revenues

Inter-Segment revenues include the following allocations:

- The allocation of business support costs to Powerex as discussed in section 8.10;
- The allocation of point-to-point transmission costs to Powerex under the Transfer Pricing Agreement; and
- An allocation of BC Hydro's cost of point-to-point transmission, which relates to transmission costs for domestic exports and transmission costs related to BC Hydro's Skagit Valley Treaty obligations to the U.S. border.

Forecast Inter-Segment revenues for the test period are shown on Appendix A, Schedule 3.0 and are provided in the table below. Over the test period, total Inter-Segment revenues are relatively consistent compared to the fiscal 2019 RRA Plan.

Table 8-10 Inter-Segment Revenues

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Powerex - Corporate Allocation	3.0 L47	(2.8)	(2.8)	(2.8)	(2.8)	(2.9)	(2.9)	(2.9)	(2.9)
2	Mark to Market Losses (Gains)	3.0 L48	0.0	(0.2)	0.0	(1.0)	0.0	0.0	0.0	0.0
3	Powerex PTP Charges	3.0 L49	(11.8)	(9.6)	(10.1)	(21.2)	(16.6)	(26.7)	(32.5)	(32.5)
4	BC Hydro PTP Charges	3.0 L50	(47.8)	(44.3)	(51.4)	(41.3)	(45.9)	(34.7)	(33.6)	(37.2)
5	Total Current Inter-Segment Revenues	3.0 L51	(62.5)	(56.9)	(64.3)	(66.4)	(65.3)	(64.3)	(69.0)	(72.6)

8.9 Subsidiary Net Income

Section 6 of Direction No. 7 required that the net income of BC Hydro's subsidiaries be included for the purpose of setting BC Hydro's rates. Although Direction No. 7 has been repealed, BC Hydro continues to include the net income of BC Hydro's subsidiaries in its revenue requirements and continues to define Trade Income on the same basis as previously defined in Direction No. 7.[334]

The inclusion of subsidiary net income in BC Hydro's revenue requirements reduces the overall revenue requirements.

BC Hydro has two subsidiaries in this regard: Powerex Corp. (**Powerex**) and Powertech Labs Inc. (**Powertech**).

In the test period, Trade Income is forecast at $120.6 million per year in fiscal 2020 and fiscal 2021 (net of BC Hydro's allocation of business support costs as described in section 8.10), and is reflective of Powerex's average net income over the last five years (i.e., fiscal years 2014 through 2018). Using a five-year average as the basis of forecasting Trade Income is consistent with prior revenue requirement applications and is reasonable given the year-to-year volatility in market conditions.

Forecast subsidiary net income for the test period is shown on Appendix A, Schedule 3.0 and is provided in the table below.

Table 8-11 Subsidiary Net Income

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Powerex Net Income	1.0 L17	(115.2)	(130.2)	(115.2)	(136.6)	(115.1)	(205.3)	(120.6)	(120.6)
2	Powertech Net Income	1.0 L18	(4.5)	(2.1)	(4.8)	(3.1)	(5.1)	(3.3)	(3.4)	(3.7)
3	Total Gross Subsidiary Net Income	1.0 L19	(119.7)	(132.4)	(119.9)	(139.6)	(120.2)	(208.6)	(124.0)	(124.3)
4	Deferral Account Additions	2.1 L16	0.0	15.1	0.0	21.4	0.0	90.2	0.0	0.0
5	Deferral Account Recoveries	2.1 L18	48.9	48.9	50.6	50.5	52.9	62.9	(12.6)	(12.6)
6	Total Current Subsidiary Net Income	3.0 L55+L56	(70.8)	(68.4)	(69.3)	(67.7)	(67.3)	(55.6)	(136.6)	(136.9)

Variances between forecast and actual Trade Income are deferred to the Trade Income Deferral Account in accordance with BCUC Order No. G-96-04. However, if actual Trade Income in a given fiscal year is less than zero (i.e., a net loss), the transfer to the Trade Income Deferral Account would be the difference between the

[334] Trade Income is the greater of (a) the amount that is equal to BC Hydro's consolidated net income, less BC Hydro's non-consolidated net income, less the net income of BC Hydro's subsidiaries except Powerex, less the amount that BC Hydro's consolidated net income changes due to foreign currency translation gains and losses on intercompany balances between BC Hydro and Powerex; and (b) zero.

forecast Trade Income and zero. This means that a net loss in Trade Income would be borne the Government of B.C. as BC Hydro's shareholder and therefore ratepayers do not bear the risk of losses in Trade Income.

8.10 Allocation of Business Support Costs

For the purpose of determining the Transmission Revenue Requirement (as described in Chapter 9), BC Hydro's business support costs are allocated to generation, transmission, distribution, and customer care functions as shown on Appendix A, Schedule 3.1.

Business support costs are expenditures that are required to support BC Hydro's Plan, Build, and Operate work functions. These are the costs related to BC Hydro's Support work function (e.g., finance, technology, human resources, communications, regulatory, safety, legal, etc.) The costs reside in several business groups across the company and include the costs associated with the following:

- Finance, Technology, Supply Chain Business Group;
- People, Customer, Corporate Affairs Business Group (excluding Customer Service KBU and Power Acquisitions and Contract Management KBU costs);
- Safety Business Group;
- Other which includes Legal, President and Chief Operating Officer, Corporate Costs, and Capitalized Costs;
- Amortization, taxes, and non-tariff revenue relating to the above business groups; and
- The operating costs of the Properties KBU, which resides in the Capital Infrastructure Project Delivery Business Group.

As shown on Appendix A, Schedule 3.1, the following business support costs are first assigned to the transmission, distribution, generation and customer care functions:

- Insurance costs are allocated based on the assets covered by the policies and the risks associated with the operations of the respective functions; and
- Fleet vehicle costs are allocated based on usage.

Non-current pension costs and the remaining business support costs are then allocated to the each of the functions based on the average of their proportionate shares of expenditures (operating costs and capital) and FTEs.

BC Hydro has allocated $2.9 million of business support costs to Powerex for each of fiscal 2020 and fiscal 2021, in accordance with Directive 9 of the BCUC's Decision on our Fiscal 2009 to Fiscal 2010 Revenue Requirements Application.

The forecast allocation of business support costs for the test period is summarized in the table below.

Table 8-12 Allocation of Business Support Costs

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Business Support Costs		(384.8)	(372.7)	(331.0)	(331.6)	(352.2)	(355.2)	(662.1)	(691.0)
2	Allocation to functional groups:									
3	Generation	3.1 L54 / L49	94.5	90.9	79.2	79.4	85.5	85.6	172.8	183.5
4	Transmission	3.1 L55 / L50	121.4	117.7	102.4	102.6	109.2	99.2	188.2	195.2
5	Distribution	3.1 L56 / L51	142.3	138.6	126.1	126.2	132.8	132.2	231.3	239.3
6	Customer Care	3.1 L57 / L52	23.8	22.8	20.5	20.5	21.8	35.4	66.9	70.2
7	Total Allocated Costs	3.1 L58 / L53	382.0	369.9	328.2	328.7	349.3	352.4	659.2	688.1
8	Powerex	3.1 L14	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9
9	Allocation of Business Support Costs		384.8	372.7	331.0	331.6	352.2	355.2	662.1	691.0
10	Business Support Costs Fully Allocated		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

For columns 1 to 5, refer to Schedule 3.1, lines 14 and 54 to 58. For columns 6 to 8, refer to Schedule 3.1, lines 14 and 49 to 53.

Business support costs are lower in the fiscal 2019 RRA plan compared to the fiscal 2020 and fiscal 2021 plan, primarily because BC Hydro is no longer transferring portions of its approved revenue requirement to the Rate Smoothing Regulatory Account, for recovery in rates in future fiscal years. Transfers to the Rate

Smoothing Regulatory Account reduced the amount of revenue collected in rates over fiscal 2015 to fiscal 2019, and were allocated to business support costs. This means that business support costs were lower than they otherwise would have been in the absence of these transfers. As shown in Appendix A, Schedule 5.0, line 90, the fiscal 2019 RRA plan includes planned transfers to the Rate Smoothing Regulatory Account in the amount of $321.4 million.

Going forward, BC Hydro is not deferring portions of its approved revenue requirements to the Rate Smoothing Regulatory Account, for recovery in future fiscal years. This means that there are no longer similar transfers being allocated to lower the business support costs, which, in turn, results in an increase in those costs in fiscal 2020 to fiscal 2021.

As an outcome of the Comprehensive Review, BC Hydro ceased using the Rate Smoothing Regulatory Account at the end of the third quarter of fiscal 2019. The balance of the Rate Smoothing Regulatory Account was written-off in December 2018 in the amount of $1.044 billion, resulting in a reduction to BC Hydro's retained earnings and a forecast net loss for BC Hydro in fiscal 2019. This means the cost of the write-off is borne by the Government of B.C., as BC Hydro's shareholder, and not by ratepayers, which will take pressure off rates in future fiscal years when BC Hydro would have otherwise recovered the outstanding balance. BC Hydro is not proposing to smooth rates over the fiscal 2020 to fiscal 2021 test period and is requesting BCUC approval to close the existing Rate Smoothing Regulatory Account.

8.11 Provisions and Other

“Provisions and Other” includes gains and losses on capital assets, dismantling costs, non-cash provision expenses and other costs that are not within the scope of other Nature View[335] expense items on BC Hydro's financial statements.

Gains and losses on capital assets include mass asset retirements, capital asset write-offs, and project write-offs.

As part of the project life-cycle progression, the project drivers, scope and leading alternative are generally revisited and re-confirmed prior to advancing into the next phase. As part of this process, there are times when decisions are made to cancel a project, change the project’s leading alternative, or reduce key project scope. These project changes can occur for various reasons including evolving asset or system needs and changes to the project cost relative to benefits. These decisions can result in capital expenditure write-offs (project write-offs), in whole or in part, if the capital costs incurred no longer have future benefit. These decisions are effective project and investment management practices and are the result of mature portfolio management practices to ensure our capital investments are prudent.

BC Hydro makes every effort to reduce and avoid project write-offs through the effective use of the early project investigation process as well as making write-off decisions as early as possible in the project lifecycle.

The fiscal 2020 to fiscal 2021 forecast for project write-offs was developed based on an evaluation of historical trends for capital project write-offs as of percentage of capital spend between fiscal 2016 to fiscal 2018. The average of the three-year historical actuals was approximately 0.9 per cent of capital expenditures. This was considered as a starting point for future year forecasts, with a decrease of 0.1 per cent per fiscal year in the test period as an estimated impact of our process

[335] Under the Nature View presentation, costs are classified by their nature (i.e., labour, materials, services, energy purchases, water rentals, amortization, etc.), rather than by their function.

improvement efforts to decrease project write-offs by identifying risks to capital expenditure write-offs earlier in the project lifecycle.

Following this forecasting methodology, the forecast for project write-offs is $9.9 million in fiscal 2020 based on 0.8 per cent of the annual capital expenditures and $9.7 million in fiscal 2021 based on 0.7 per cent of the annual capital expenditures. The annual capital expenditures used for this calculation exclude the Site C Project and the 2017 Waneta Transaction.

Forecast Provisions and Other are shown on Appendix A, Schedule 5.0 and are also summarized in the table below.

Table 8-13 Provisions and Other

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8
1	Total Gross Provisions & Other	5.0 L110	66.0	63.6	61.0	152.3	51.7	82.3	108.2	87.0
2	Deferral Account Additions	5.0 L102	0.0	0.0	0.0	(1.6)	0.0	0.0	0.0	0.0
3	Regulatory Account Transfers	5.0 L109	(1.2)	19.5	10.0	(35.4)	14.0	(16.7)	8.1	8.1
	Regulatory Account Recoveries									
4	Remediation, Dismantling and Other	5.0 L78:L89	40.8	39.2	32.5	34.0	30.9	30.9	50.9	47.7
5	Rate Smoothing	5.0 L90	(216.5)	(201.2)	(311.0)	(326.2)	(321.4)	814.9	0.0	0.0
6	Total Current Provisions & Other	5.0 L92	(111.0)	(79.0)	(207.5)	(177.0)	(224.8)	911.4	167.1	142.8

Over the test period, Provisions and Other are forecast to increase compared to the fiscal 2019 RRA plan primarily due to higher planned dismantling costs, capital asset write-offs and project write-offs, which are included in line 1 of Table 8-13. The fiscal 2020 Plan amount for dismantling costs is higher than the fiscal 2021 Plan due to forecast dismantling costs in fiscal 2020 related to the John Hart Generating Station Replacement project in that year.

Additionally, Current Provisions and Other are increasing, compared with fiscal 2019 RRA plan, due to higher regulatory account recoveries associated with dismantling cost variances which were transferred to the Dismantling Cost Regulatory Account during fiscal 2018 and fiscal 2019, and which are included in line 4 of Table 8-13.

Also, as shown in line 5 of Table 8-13, for revenue requirement modelling purposes, and only until the end of fiscal 2019, transfers to and from the Rate Smoothing Regulatory Account are included in Provisions and Other (as shown in Appendix A, Schedule 5, line 90). For external reporting purposes, transfers to the Rate Smoothing Regulatory Account are included in Domestic Revenues.

As an outcome of the Comprehensive Review, BC Hydro ceased using the Rate Smoothing Account at the end of the third quarter of fiscal 2019. The balance of the Rate Smoothing Regulatory Account was written-off in December 2018. In this Application, BC Hydro is requesting approval to close the Rate Smoothing Regulatory Account in fiscal 2020 as this account has a zero balance.

8.12 Accounting Policy Matters

8.12.1 Accounting Treatment of Certain Electricity Purchase Agreements

BC Hydro is required to review all EPAs to determine whether the EPAs are leases under IFRS. As identified in section 8.13.3, a new Leases standard, IFRS 16, is effective for fiscal 2020.

The fiscal 2020 to fiscal 2021 forecast includes one EPA accounted for as a lease under IFRS 16, *Leases*. Prior to fiscal 2020, this EPA was an operating lease under IAS 17, *Leases*. The costs related to this EPA were previously classified as cost of energy. The IFRS 16 lease treatment of the EPA results in payments under the EPA being classified as amortization and finance charges.

Table 8-14 below indicates the classification of costs associated with the Electricity Purchase Agreement and also has references to the financial schedules in Appendix A where the costs of the Electricity Purchase Agreement is included.

Table 8-14 Treatment of the Qualifying Electricity Purchase Agreement

($ million)	Schedule Reference	F2020 Plan	F2021 Plan
Amortization	7.0 L11	30.2	30.2
Finance Charges	8.0 L15	4.2	2.8
Total		**34.4**	**33.0**

During the Previous Application, BC Hydro advised the BCUC that the commercial operation date for two EPAs classified as capital leases was delayed.[336] In addition, one EPA was reassessed due to an extension agreement, and it was determined that the EPA should be treated as an operating lease for the period following the extension in fiscal 2018. These events resulted in favorable variances of $12.8 million in fiscal 2017 and $53.0 million in fiscal 2018 which were deferred to the Non-Heritage Deferral Account. The deferral to the Non-Heritage Deferral Account was not required under existing regulatory orders, but was done to provide the benefit to ratepayers.

Table 8-15 below shows the impact of the delayed commercial operation date and lease extension in fiscal 2017 and fiscal 2018, including the deferral of $12.8 million and $53.0 million respectively into the Non-Heritage Deferral Account.

Table 8-15 Income Statement Impact from Delayed Commercial Operation Date and Lease Extension

($ million)	F2017 Actual	F2017 RRA	Difference (RRA-Actual)	F2018 Actual	F2018 RRA	Difference (RRA-Actual)
Income Statement						
Domestic Energy Costs	9.0	12.3	3.4	7.5	13.0	5.5
Operating Costs	9.7	18.8	9.1	17.0	54.1	37.1
Taxes	1.7	2.1	0.4	1.8	3.6	1.9
Depreciation and Amortization	6.5	9.8	3.3	8.2	22.2	14.0
Finance Charges	3.1	8.7	5.6	2.3	28.8	26.5
Subtotal	30.0	51.8	21.8	36.8	121.7	84.9

336 Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Exhibit B-9, BCUC IR 1.131.3.

($ million)	F2017 Actual	F2017 RRA	Difference (RRA-Actual)	F2018 Actual	F2018 RRA	Difference (RRA-Actual)
Items within the Scope of Existing Orders						
Finance Charges (Total Finance Charges Regulatory Account)	5.6	0.0	(5.6)	26.5	0.0	(26.5)
Cost of Energy (NHDA)	3.4	0.0	(3.4)	5.5	0.0	(5.5)
Subtotal	9.0	0.0	(9.0)	31.9	0.0	(31.9)
Items Outside the Scope of Existing Orders						
Depreciation and Amortization (applied to NHDA)	3.3	0.0	(3.3)	14.0	0.0	(14.0)
Operating Costs (applied to NHDA)	9.1	0.0	(9.1)	37.1	0.0	(37.1)
Taxes (applied to NHDA)	0.4	0.0	(0.4)	1.9	0.0	(1.9)
Total Deferred to NHDA	**12.8**	**0.0**	**(12.8)**	**53.0**	0.0	**(53.0)**
Income Statement Impact	51.8	51.8	0.0	121.7	121.7	0.0

8.13 International Financial Reporting Standards (IFRS)

BC Hydro prepares its financial statements in accordance with IFRS, effective for its fiscal year ending March 31, 2019 and has prepared the Application in accordance with IFRS in effect as at April 1, 2019.

BC Hydro fully adopted IFRS in fiscal 2019 subsequent to Treasury Board Regulation 231/2018 (issued on November 7, 2018), which repealed Part 3 of Government Organization Accounting Standards Regulation 257/2010. Previously, under Part 3 of Government Organization Accounting Standards Regulation 257/2010, BC Hydro prepared its financial statements in accordance with the principles of IFRS, combined with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980, *Regulated Operations* (collectively, the “Prescribed Standards”). As part of BC Hydro fully adopting IFRS in fiscal 2019, BC Hydro elected to adopt IFRS 14, *Regulatory Deferral Accounts* to allow BC Hydro to continue to use rate-regulated accounting. BC Hydro adopted IFRS including the interim rate regulated accounting standard, IFRS 14, *Regulatory Deferral Accounts*, effective for its fiscal year ending March 31, 2019.

In fiscal 2019, BC Hydro adopted two new IFRS standards that were effective beginning in fiscal 2019:

- IFRS 9, *Financial Instruments*; and
- IFRS 15, *Revenue from Contracts with Customers*.

The International Accounting Standards Board has issued a new standard relevant to the test period covered by this Application:

- IFRS 16, *Leases* – effective in fiscal 2020 for BC Hydro.

Significant impacts of the IFRS adoption are identified below.

8.13.1 IFRS 9, Financial Instruments

IFRS 9 Financial Instruments replaced IAS 39, *Financial Instruments: Recognition and Measurement*.

The adoption of IFRS 9 resulted in some additional financial statement note disclosure, but did not result in any material changes to BC Hydro's financial statements or this Application.

8.13.2 IFRS 15, Revenue from Contracts with Customers

IFRS 15, *Revenue from Contracts with Customers* replaced IAS 18, *Revenue*, IAS 11, *Construction Contracts* and IFRIC 18, *Transfers of Assets from Customers*.

The adoption of IFRS 15 impacted the accounting for two contracts, the Skagit River Agreement and a Tariff Supplement No. 37 Northwest Transmission Line Supplemental Charge agreement.

Under the terms of the Skagit River Agreement, the customer makes 35 annual payments for electricity provided by BC Hydro over 80 years. When a customer makes payments in advance of services being provided, a financing arrangement is considered to exist under IFRS 15. IFRS 15 requires that the payments under a financing arrangement are adjusted for the time value of money (e.g., interest) based on the interest rate in effect at the inception of the contract. The objective of the financing adjustment is to recognize revenue at an amount that reflects the price that a customer would have paid for the goods or services if the customer had paid cash for those goods or services when (or as) they are provided to the customer. The financing adjustment results in higher revenues and higher interest expenses recognized over the term of the contract.

BC Hydro recognized a $319 million reduction in unearned revenue, at April 1, 2018, as a result of the financing adjustment under IFRS 15. Unearned revenue decreased because BC Hydro earned more revenue (net of interest expense) to date under IFRS 15 than under IAS 18. By Order No. G-96-04, BCUC approved the deferral of variances related to Skagit Valley Treaty revenues to the Heritage Deferral Account. Accordingly, the impact related to this accounting change was deferred to the Heritage Deferral Account, to the benefit of ratepayers (i.e., a decrease in the balance of the Heritage Deferral Account).

Tariff Supplement No. 37 enables BC Hydro to recover its costs incurred in constructing the Northwest Transmission Line from customers receiving electricity or generator interconnection service by means of the Northwest Transmission Line. Tariff Supplement No. 37 permits customers to make payments in installments over a shorter period than the expected term of service to the customer. IFRS 15 includes new guidance that permits the recognition of a receivable only when the entity has an unconditional right to the payment. As BC Hydro is required to deliver future services associated with these installment payments, BC Hydro does not have an unconditional right to payment; therefore, the payments due cannot be recognized as a receivable under IFRS 15. In this case, the right to consideration would be unconditional if BC Hydro was not required to continue to supply electricity to the customer. Prior to the adoption of IFRS 15, BC Hydro recognized a receivable and unearned revenue associated with the future payments due under the Tariff Supplement No. 37 agreement.

As a result, BC Hydro recognized a decrease of $51 million in non-current receivables and a decrease of $47 million in unearned revenue attributable to an installment agreement at April 1, 2018. The net difference of $4 million was recognized as a $1 million decrease in the Non-Heritage Deferral Account[337] balance and a $5 million increase in the Total Finance Charges Regulatory Account[338] balance, consistent with existing orders.

There are changes to the ongoing measurement of revenue and interest charges relating to these agreements as a result of the application of IFRS 15 for fiscal 2019. The fiscal 2019 variances in revenue and interest expense as a result of these changes were similarly deferred to in the Heritage Deferral Account, the Non-Heritage Deferral Account and the Total Finance Charges Regulatory Account as described above, consistent with existing orders.

8.13.3 IFRS 16, Leases

IFRS 16, *Leases* replaces the existing standard IAS 17, *Leases* and IFRIC 4, *Determining Whether an Arrangement Contains a Lease* for annual periods beginning on or after January 1, 2019. IFRS 16 eliminates the classification of leases as either operating or capital leases required under IAS 17, and instead, introduces a single lease accounting model for lessees. Under the new single lease model, a lessee will recognize the lease assets and lease liabilities on the balance sheet initially measured at the present value of the lease payments, with the exception of leases with a duration of twelve months or less and leases with low

[337] Variances between forecast and actual revenues related to Tariff Supplement No. 37 Northwest Transmission Line Supplemental Charge are deferred to the Non-Heritage Deferral Account, in accordance with BCUC Order No. G-68-17.

[338] Variances between forecast and actual finance charges are deferred to the Total Finance Charges Regulatory Account, in accordance with BCUC Order No. G-47-18.

value. IFRS 16 will also cause expenses to be higher at the beginning and lower towards the end of a lease, even when payments are consistent throughout the term because the interest expense declines over time as the liability balance is drawn down.

BC Hydro has currently determined that all existing EPAs, except one, are not leases under IFRS 16. Upon transition to IFRS 16 on April 1, 2019, BC Hydro expects to derecognize three existing EPAs and recognize one EPA lease. The forecast adjustment at transition for these EPAs is shown in the table below.

Table 8-16 Electricity Purchase Agreements Forecast Adjustment at Transition

Financial Statement Item Debit/(Credit)	IFRS 16 Adjustment at April 1, 2019 ($ million)
Prepaid Lease	(17.7)
Property, Plant and Equipment	(617.7)
Right-of-Use Assets	93.1
Lease Obligations	560.4
Net change	**(18.0)**

The net credit adjustment, estimated in the amount of $18 million, will be recorded as a decrease to the balance in the Non-Heritage Deferral Account in fiscal 2020, to the benefit of ratepayers. This is not required under existing orders, but is being done to provide the benefit to ratepayers.

The table below presents the classification and measurement of the forecast expenses associated with these agreements under IFRS 16 and IAS 17 for fiscal 2020 and fiscal 2021.

Table 8-17 IFRS 16 and IFRS 17 Forecast Expenses

($ million)	Three EPA Leases Derecognized		One EPA Lease Recognized	
	F2020	F2021	F2020	F2021
IAS 17				
Operating expenses	54.5	55.1		
Grants and Taxes	2.5	2.6		
Depreciation	22.8	22.8		
Finance Charges	41.7	40.8		
Cost of Energy	7.5	8.5	39.6	39.5
Total	**129.0**	**129.9**	**39.6**	**39.5**
IFRS 16				
Depreciation			30.2	30.2
Finance Charges			4.2	2.8
Cost of Energy	118.6	120.3		
Total	**118.6**	**120.3**	**34.4**	**33.0**
Net Change	**(10.4)**	**(9.6)**	**(5.2)**	**(6.5)**

With respect to EPAs, BC Hydro has made estimates based on its preliminary assessment regarding the impacts of IFRS 16 (which will become effective for BC Hydro on April 1, 2019) and has included them in this application. However, the actual impacts of the new standard may vary from these estimates as BC Hydro completes its assessment, including as a result of clarifications and interpretive guidance that may be developed by the International Accounting Standards Board, accounting firms and industry groups to assist in the implementation of the new standard. BC Hydro anticipates that material variances are possible when we complete our assessment of EPAs, including the review by our external auditors. As shown in section 8.12.1, BC Hydro has deferred positive variances related to EPA capital leases into the Non-Heritage Deferral Account in order to provide the benefit to ratepayers, even though this was not required under existing orders. Accordingly, BC Hydro requests BCUC approval to defer to the Non-Heritage Deferral Account, any variances related to the accounting for EPAs determined to be leases under IFRS 16, that are not eligible for deferral treatment under existing orders.

In addition, BC Hydro has performed a review of all significant non-EPA agreements potentially within the scope of IFRS 16 and has currently determined that five agreements, mainly property lease/rental agreements, will be required to be recognized as leases under IFRS 16. The forecast adjustment at transition for these agreements is shown in the table below.

Table 8-18 IFRS 16, *Leases* Forecast Adjustment at Transition

Financial Statement Item Debit/(Credit)	IFRS 16 Adjustment at April 1, 2019 ($ million)
Right-of use asset	16.8
Lease obligation	(17.6)
Net Change	**0.8**

The table below presents the classification and measurement of the forecast expenses associated with these agreements under IFRS 16 and IAS 17 for fiscal 2020 and fiscal 2021.

Table 8-19 IFRS 16 and IFRS 17 Forecast Expenses

	F2020 ($ million)	F2021 ($ million)
IAS 17		
Operating expenses	3.9	3.9
IFRS 16		
Depreciation	3.1	3.2
Finance Charges	1.0	1.0
Total	4.2	4.2
Net Change	**0.3**	**0.3**

8.13.4 IFRS 14, Regulatory Deferral Accounts

As a result of BC Hydro's adoption of IFRS 14, *Regulatory Deferral Accounts,* the interest during construction rate will differ from the weighted average cost of debt rate used for applying interest to applicable regulatory accounts, starting in fiscal 2020.

IFRS 14 requires BC Hydro to implement presentation and disclosure changes to its financial statements. IFRS 14 requires regulatory deferral account balances and changes to balances to be presented separately from non-regulatory amounts on the balance sheet and the income statement.

Prior to the adoption of IFRS 14, BC Hydro expected to classify the amortization of the Debt Management Regulatory Account as finance charges, include this amortization in the calculation of BC Hydro's weighted average cost of debt, which is used to apply interest during construction to capital projects and interest to applicable regulatory accounts. BC Hydro's expectation that it would include Debt Management Regulatory Account amortization in the determination of its weighted average cost of debt was reflected in BCUC Order No. G-42-16 to the Debt Management Regulatory Account which authorized that: "Amounts amortized to finance charges from the DMRA are also eligible to be included in the calculation of Interest During Construction." Therefore, upon initiation of amortization of the Debt Management Regulatory Account in fiscal 2020, consistent with BCUC Order No. G-42-16, BC Hydro expected to allocate a portion of the amortization to capital asset balances beginning in fiscal 2020.

However, under IFRS 14, the Debt Management Regulatory Account amortization is required to be presented separately from non-regulatory items and therefore cannot be netted against finance charges. As a result, the IFRS 14 requirement for separation of regulatory balances and transactions from non-regulatory items requires that the Debt Management Regulatory Account amortization be excluded from the interest during construction calculation used for capitalizing borrowing costs to capital assets. To be compliant with IFRS, BC Hydro will not be permitted to include Debt Management Regulatory Account amortization in the determination of the weighted average cost of borrowing for applying interest during construction as it had expected and communicated to the BCUC. Therefore, for the purposes of applying interest during construction, BC Hydro will calculate its weighted average cost of borrowing excluding Debt Management Regulatory Account amortization and will refer to this as the interest during construction rate.

BC Hydro will continue to calculate the weighted average cost of debt rate to be used for applying interest to the balances of regulatory accounts, as applicable. This rate will include Debt Management Regulatory Account amortization. It will also be used to determine the amount of the Debt Management Regulatory Account amortization that would have been capitalized to the Site C Project had the interest during construction rate included Debt Management Regulatory Account amortization. This amount would be deferred to the Site C Regulatory Account as described below.

In its Decision on our Previous Application the BCUC approved that any costs related to the Site C Project that are not able to be capitalized, be deferred to the Site C Regulatory Account. Accordingly, the forecast amounts related to the Debt Management Regulatory Account amortization that would otherwise have been included as part of the forecast interest during construction amount related specifically to the Site C Project, would be eligible to be deferred to the Site C Regulatory Account. The annual impact related to the Site C Project is approximately $2.0 million in fiscal 2020 and $2.7 million in fiscal 2021.

Furthermore, this treatment is consistent with BCUC Order No. G-42-16, which approved the establishment of the Debt Management Regulatory Account and that approved the inclusion of the Debt Management Regulatory Account amortization in the calculation of interest during construction.

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Revenue Requirements Application

Chapter 9

Transmission Revenue Requirement

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9.1 Introduction

This chapter describes how BC Hydro's proposed Open Access Transmission Tariff (**OATT**) rates are determined to recover BC Hydro's Transmission Revenue Requirement (**TRR**), consistent with past Orders of the BCUC. The rates charged under the OATT are for Network Integration Transmission Service (**NITS**), Point-To-Point (**PTP**) Transmission Service and Ancillary Services, as set out in Appendix EE and summarized in Table 9-8 . As the main users of the transmission system, BC Hydro and Powerex account for approximately 98.5 per cent of the revenue collected through the OATT. External transmission customers account for approximately 1.5 per cent of the revenue.

The rates charged under the OATT are designed to collect the TRR, which is the sum of BC Hydro's net transmission function costs, as calculated using a cost of service methodology. The cost of service methodology is consistent with the method used in BC Hydro's previous revenue requirement applications. It is also consistent with the method previously used by the British Columbia Transmission Corporation (**BCTC**), and the method approved in the BCUC's 1998 Decision accompanying Order No. G-43-98 related to BC Hydro's Application for Approval of Wholesale Transmission Services. The design of the OATT rates is also consistent with previously approved OATT rates. The proposed OATT rates are just and reasonable and should be approved as sought.

This chapter is organized as follows:

- Section 9.2 describes how the TRR is determined through the direct assignment or allocation of transmission-related costs to the transmission function, based on cost causation principles and consistent with past practice;
- Section 9.3 sets out the proposed OATT rates and describes how the rates were derived, consistent with past practice;
- Section 9.4 explains the forecast of PTP revenue; and

- Section 9.5 presents the proposed OATT rates for the test period.

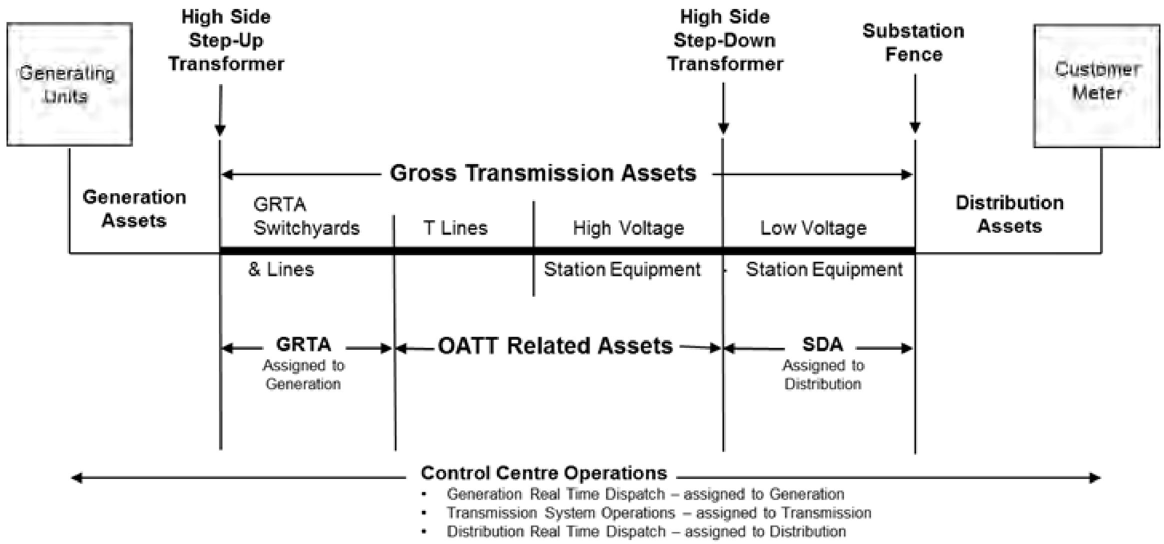
9.2 Transmission Revenue Requirements are Calculated using a Cost of Service Allocation Methodology Consistent with Past Orders

BC Hydro's TRR is BC Hydro's net transmission-related costs, as determined through an allocation or direct assignment of BC Hydro's costs. The cost of service methodology used to derive the TRR is based on cost causation and is consistent with the methodology. The methodology is consistent with that previous methodology used by BC Hydro and BCTC and approved in the BCUC's 1998 Decision accompanying Order No. G-43-98 related to BC Hydro's Application for Approval of Wholesale Transmission Services.

9.2.1 Transmission Revenue Requirement Overview

The TRR includes the current costs associated with BC Hydro's OATT Related Assets, which are the transmission lines and high-voltage station equipment used to provide transmission service pursuant to the OATT. As shown by the asset boundaries in Figure 9-1, BC Hydro's Gross Transmission Assets include assets from the high voltage side of the step-up transformers located at the generation stations to the substation fence at distribution voltage. Both Generation Related Transmission Assets (**GRTA**) and Substation Distribution Assets (**SDA**) must be excluded from the Gross Transmission Assets to arrive at the OATT Related Assets.

Figure 9-1 Asset Boundary for Transmission Revenue Requirement and OATT Rates



Using fiscal 2020 as an example, Figure 9-2 illustrates the allocation and direct assignment of costs to establish the gross transmission costs related to the Gross Transmission Assets in Figure 9-1, the TRR related to the OATT Related Assets in Figure 9-1, and the recovery of the TRR through the proposed OATT rates.

Figure 9-2 Fiscal 2020 Transmission Revenue Requirement Components ($ million) with References to Appendix A Financial Schedules

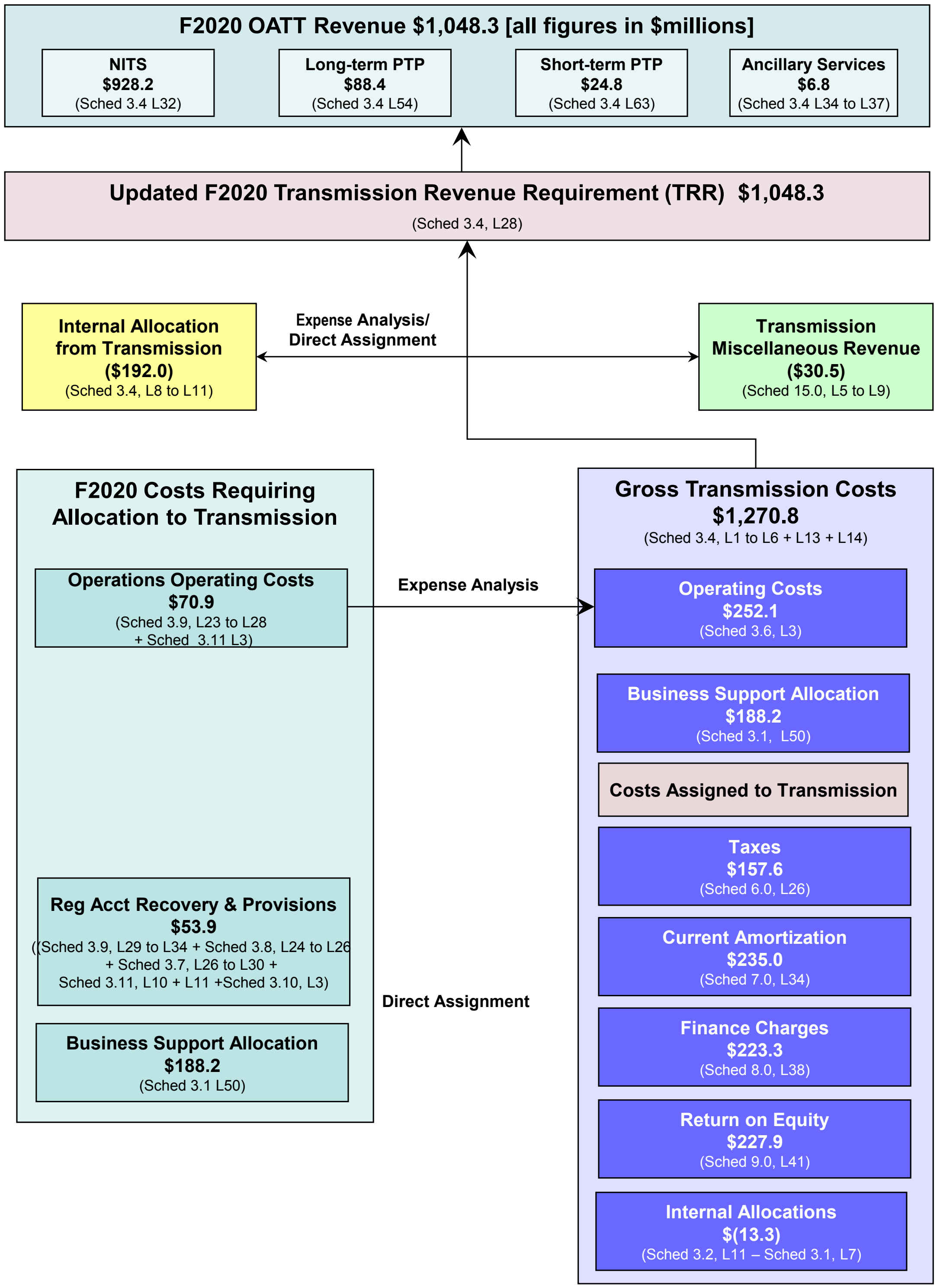


Table 9-1 sets out the cost components that make up the TRR from fiscal 2017 through fiscal 2021. The fiscal 2017, fiscal 2018, and fiscal 2019 approved amounts represent the plan amounts from the Previous Application, as reflected in the OATT rate schedules included in BC Hydro's compliance filing pursuant to BCUC Order No. G-47-18.

The 13 per cent increase in Gross Transmission Costs and 15 per cent increase in the TRR from fiscal 2019 RRA to the fiscal 2020 plan is due to several factors:

- ***Business Support Costs***: As with the general rate increase, a significant driver of the increase in the TRR is an end to the practice of rate smoothing, as a result of the Comprehensive Review. Business support costs are lower in the fiscal 2019 RRA plan compared to the fiscal 2020 and fiscal 2021 plan, primarily because BC Hydro is no longer transferring portions of its approved revenue requirement to the Rate Smoothing Regulatory Account, for recovery in rates in future fiscal years. Transfers to the Rate Smoothing Regulatory Account reduced the amount of revenue collected in rates over the fiscal 2015 to fiscal 2019 period, and were allocated to business support costs. This means that business support costs were lower than they otherwise would have been in the absence of these transfers.[339]

  As a result, business support costs allocated to gross transmission are increasing by approximately 72 per cent from fiscal 2019 RRA to fiscal 2020 plan. Business support costs are discussed further in Chapter 8, section 8.10 and their allocation to gross transmission is discussed in section 9.2.7;

- ***Finance Charges***: A credit balance in the Total Finance Charges Regulatory Account was refunded to ratepayers over the fiscal 2017 to fiscal 2019 period,

[339] As shown in Appendix A, Schedule 5.0, line 90, the fiscal 2019 RRA Plan includes planned transfers to the Rate Smoothing Regulatory Account in the amount of $321.4 million.

which resulted in lower finance charges in fiscal 2019. In this application, forecast finance charges are increasing primarily because this credit balance has now been returned to ratepayers and is no longer offsetting total finance charges in this test period. The other main reason for the increase in finance charges is an increase to forecast borrowing costs, primarily due recent capital expenditures. These increases are partially offset by a decrease in finance charges related to an increase in interest during construction. As a result, finance charges allocated to gross transmission increase by 16.9 per cent from the fiscal 2019 RRA to the fiscal 2020 Plan. Finance charges are discussed further in Chapter 8, section 8.5 and their allocation to gross transmission is discussed in section 9.2.6.2;

- ***Amortization***: Current amortization cost, including demand side management amortization, allocated to gross transmission is increasing by 1.8 per cent from the fiscal 2019 RRA to the fiscal 2020 plan. Amortization is discussed further in Chapter 8, section 8.2 and its allocation to gross transmission is discussed in section 9.2.6.2;
- ***Operating Costs and Provisions:*** Operating costs and provisions allocated to gross transmission have increased by 5.8 per cent from the fiscal 2019 RRA to the fiscal 2020 plan. Operating costs are discussed further in Chapter 5 and Provisions are discussed in Chapter 8, section 8.11. The allocation of these costs to gross transmission is described in section 9.2.5; and
- ***Taxes***: As with the general rate increase, taxes paid by BC Hydro are increasing due to increased assessed property values, the completion of new capital projects that are subject to taxation and increases to provincial and municipal taxation rates. The resulting taxes allocated to gross transmission increase by approximately 7.1 per cent from the fiscal 2019 RRA to the fiscal 2020 plan. Taxes are discussed further in Chapter 8, section 8.6 and the allocation of taxes to gross transmission is described in section 9.2.6.1.

The following factors are offsetting the increase in gross transmission costs and OATT rates:

- ***Return on Equity***: Return on Equity allocated to gross transmission is decreasing by 6.9 per cent from the fiscal 2019 RRA to the fiscal 2020 plan. Return on Equity is discussed further in Chapter 8, section 8.3 and its allocation to gross transmission is described in section 9.2.6.2; and
- ***Miscellaneous Revenues***: As discussed further in section 9.2.10,certain miscellaneous transmission revenues offset the TRR and OATT rates. However, there is no reduction to the TRR from the lease and other revenues related to BC Hydro's Waneta acquisition (discussed further in Chapter 4, section 4.2.3), as these revenues are non-transmission revenues.

The following factors offset the general revenue requirements but do not offset the gross transmission cost or TRR:

- ***Subsidiary Net Income***: Subsidiary net income does not reduce the gross transmission cost or TRR. Gross transmission has no energy component, which means that net income from BC Hydro's energy trading subsidiary, Powerex, does not reduce the TRR. Costs and revenues associated with our subsidiary Powertech, also do not reduce the TRR as they are not transmission related;
- ***Cost of Energy***: As gross transmission has no cost of energy component, there is no offset to gross transmission or the TRR due to the proposed refund of the credit balance of the Heritage Deferral Account and Non-Heritage Deferral Account, as discussed in Chapter 7, section 7.7.1; and
- ***Deferral Account Rate Rider (DARR)***: There is no offset to OATT rates associated with the reduction of the DARR from 5 per cent to 0 per cent on April 1, 2019. OATT rates have never been subject to the DARR and the elimination of the DARR has no OATT customer bill impact.

The allocation or direct assignment of the components of the TRR is discussed in the sections below.

1 **Table 9-1 Transmission Revenue Requirement**

		F2017 RRA ($ million)	F2017 Actual ($ million)	F2018 RRA ($ million)	F2018 Actual ($ million)	F2019 RRA ($ million)	F2019 Forecast ($ million)	F2020 Plan ($ million)	F2021 Plan ($ million)
		1	2	3	4	5		6	7
1	Operating Cost and Provisions	256.5	264.7	249.0	268.0	238.3	253.6	252.1	256.5
2	Taxes	137.6	137.9	141.7	143.8	147.2	152.0	157.6	163.7
3	Amortization	210.2	215.7	220.8	225.8	230.7	228.7	235.0	237.3
4	Finance Charges	177.4	178.7	180.0	182.5	191.0	187.0	223.4	209.1
5	Allowed Net Income	240.5	242.4	245.3	243.2	244.8	(142.8)	227.9	224.7
6	Business Support Cost	121.4	117.7	102.4	102.6	109.2	99.2	188.2	195.2
7	Internal Allocations to Transmission								
8	Generation Ancillary Services	2.5	2.0	2.5	2.7	2.5	2.5	2.8	2.8
9	Transmission Capitalized Overhead	(16.7)	(16.7)	(16.9)	(16.9)	(17.1)	(17.8)	(16.1)	(16.3)
10	Transmission Rate Smoothing Regulatory Account Write-off						382.5		
11	Gross Transmission Costs	1,129.5	1,142.4	1,124.9	1,151.8	1,146.5	1,144.9	1,270.8	1,273.0
12	Less Internal Allocations from Transmission								
13	Generation Related Transmission Assets	(43.3)	(43.3)	(43.3)	(43.3)	(43.3)	(43.3)	(43.3)	(43.3)
14	Generation Real Time Dispatch	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(2.3)	(2.3)
15	Distribution Real Time Dispatch	(16.8)	(16.7)	(16.4)	(16.4)	(16.7)	(16.7)	(20.0)	(20.4)
16	Substation Distribution Assets	(125.2)	(125.6)	(128.3)	(127.6)	(125.9)	(125.9)	(126.5)	(128.1)
17	Less Miscellaneous Revenues								
18	Fortis General Wheeling Agreement	(4.7)	(4.8)	(4.9)	(5.1)	(5.0)	(5.2)	(5.2)	(5.3)
19	Secondary Revenues	(5.1)	(7.6)	(5.1)	(7.5)	(5.0)	(6.0)	(6.0)	(6.2)
20	Interconnections	(3.0)	(3.6)	(1.9)	(2.9)	(1.9)	(1.9)	(2.2)	(2.2)
21	Amortization of Contributions	(13.6)	(13.5)	(14.2)	(14.4)	(14.4)	(14.6)	(14.8)	(15.3)
22	NTL Supplemental Charges	(2.7)	(2.7)	(2.0)	(2.0)	(2.0)	(2.3)	(2.3)	(2.3)
23	Subtotal	(216.0)	(219.4)	(217.7)	(220.7)	(215.9)	(217.5)	(222.5)	(225.4)
24	Transmission Revenue Requirement	913.5	923.0	907.2	931.1	930.7	927.4	1,048.3	1,047.6

9.2.2 Allocation of Operating Costs to Gross Transmission

Consistent with past practice, current operating costs and provisions are directly assigned or allocated to the transmission function based on cost causation.

The following business groups currently carry out transmission functions:

1. Integrated Planning Business Group (discussed in Chapter 5A);
2. Capital Infrastructure Project Delivery Business Group (discussed in Chapter 5B);
3. Operations Business Group (discussed in Chapter 5C); and
4. Finance, Technology, Supply Chain Business Group (discussed in Chapter 5E);

The sections below describe how the operating costs for each of these Business Groups are allocated to the Generation, Transmission and Distribution functions.

9.2.2.1 Functions of the KBUs in the Integrated Planning Business Group

Integrated Planning Business Group operating costs are functionalized as follows:

- Energy Planning and Analytics KBU operating costs are allocated between the Generation, Transmission, Distribution functions and to business support;
- Dam Safety KBU operating costs are directly assigned to the Generation function;
- Line Asset Planning KBU operating costs are allocated between the Generation, Transmission and Distribution functions;
- Engineering KBU operating costs are allocated between the Generation, Transmission and Distribution functions;
- Stations Asset Planning KBU operating costs are allocated between the Generation, Transmission and Distribution functions; and

- Interconnections and Shared Assets KBU operating costs are allocated between the Transmission and Distribution functions.

9.2.2.2 Functions of the KBUs in the Capital Infrastructure Project Delivery Business Group

Capital Infrastructure Project Delivery Business Group operating costs are functionalized as follows:

- Project Delivery KBU operating costs are allocated between the Generation, Transmission and Distribution functions;
- Indigenous Relations KBU operating costs are allocated between the Generation, Transmission and Distribution functions and to business support;
- Environment KBU operating costs are allocated between the Generation, Transmission and Distribution functions and to business support; and
- Properties KBU operating costs are allocated between the Generation, Transmission and Distribution functions and to business support.

9.2.2.3 Functions of the KBUs in the Operations Business Group

Operations Business Group operating costs are functionalized as follows:

- Line Field Operations KBU operating costs are allocated between the Generation, Transmission, and Distribution functions;
- Stations Field Operations KBU operating costs are allocated between the Generation, Transmission and Distribution functions;
- T&D System Operations KBU operating costs are allocated between the Generation, Transmission and Distribution functions;
- Generation System Operations KBU operating costs are directly assigned to the Generation function;

- Program and Contract Management KBU operating costs are allocated between the Generation, Transmission and Distribution functions;
- Distribution Design and Customer Connections KBU operating costs are directly assigned to the Distribution function; and
- Construction Services KBU operating costs are allocated between the Generation, Transmission and Distribution functions.

9.2.2.4 Functions of the KBUs in the Finance, Technology, Supply Chain Business Group

The Materials Management Department and Fleet Services Department, both part of the Supply Chain KBU, are functionalized as follows:

- Materials Management Department operating costs are allocated between the Generation, Transmission and Distribution functions; and
- Fleet Services Department operating costs are allocated between the Generation, Transmission Distribution and Customer Service functions.

The remainder of the Finance, Technology, Supply Chain Business Group operating costs are functionalized as business support, based on corporate allocators.

9.2.3 Activities of the KBUs by Function

The portion of the operating costs and the internal allocations relating to the transmission function are calculated by determining the relevant functional activity of each KBU within the Business Groups. The functional activities performed by the relevant Business Groups are shown in Table 9-2.

Table 9-2 KBU Functional Activities

1	**Generation Function:**	
	(i)	Generation Real-time Dispatch
	(ii)	Generation Related Transmission Assets
	(iii)	Generation Other
2	**Transmission Function:**	
	(i)	Scheduling, System Control and Dispatch Service (OATT Rate Schedule 03)
	(ii)	Transmission Other
3	**Distribution Function:**	
	(i)	Substation Distribution Assets
	(ii)	Distribution Real-time Dispatch
	(iii)	Distribution Other

9.2.4 Methodologies for Allocating Costs to Functional Activities

Where possible, costs are directly assigned to one of the functional activities shown in Table 9-2. Where direct assignment is not possible, costs are allocated to the functional activities, using one or more of the following parameters to develop allocation factors:

(i) Planned expenditures for maintenance and/or capital programs that are representative of the work a KBU expects to undertake during the test period;

(ii) Historical expenditures for work performed by a KBU;

(iii) Work performed by Full-Time Equivalents (**FTEs**) within a KBU;

(iv) Manager and financial analyst interviews; and

(v) Direct allocation of certain specific activity costs.

In most cases, functionalization at the Director and Vice President levels is based on a roll-up of the overall allocation of the Departments or KBUs for which they are responsible.

Functionalization for provisions and other is based on an analysis of related current and historical capital programs.

Table 9-3 summarizes the allocation approach used for each KBU or Department in the Integrated Planning, Capital Infrastructure Project Delivery, Operations, and Finance, Technology, Supply Chain Business Groups.

Table 9-3 Allocation of Costs to Functional Activities

KBU/Department	Basis of Allocation to Functional Activities
Integrated Planning Business Group	
Energy Planning and Analytics	Direct assignment and manager interviews
Dam Safety	Direct assignment to generation function
Line Asset Planning	Direct assignment, maintenance and capital programs, and manager interviews
Engineering	Direct assignment, capital programs and manager interviews
Stations Asset Planning	Direct assignment, maintenance and capital programs, and manager interviews
Interconnections and Shared Assets	Direct assignment and manager interviews
Business Unit Support	Direct assignment roll-up of overall allocation
Capital Infrastructure Project Delivery Business Group	
Project Delivery	Capital programs managed by the Project Delivery KBU and manager interviews
Indigenous Relations	Activity analysis and manager interviews
Environment	Direct assignment and manager interviews
Properties	Direct assignment and manager interviews
Business Unit Support	Direct assignment roll-up of overall allocation
Operations Business Group	
Line Field Operations	Direct assignment, maintenance and capital programs, specific activity analysis and manager interviews
Stations Field Operations	Direct assignment, maintenance and capital programs, specific activity analysis, and manager interviews
T&D System Operations	Direct assignment, specific activity analysis, and manager interviews
Generation System Operations	Direct assignment to generation function
Program and Contract Management	Specific activity analysis, maintenance and capital programs, and manager interviews
Distribution Design and Customer Connections	Direct assignment to distribution function
Construction Services	Maintenance and capital programs, specific activity analysis, and manager interviews
Business Support	Direct assignment roll-up of overall allocation

KBU/Department	Basis of Allocation to Functional Activities
Finance, Technology, Supply Chain Business Group	
Materials Management	Manager interviews
Fleet Services	Manager interviews

9.2.5 Resulting Portion of Business Groups Assigned to Gross Transmission Operating Costs

As a result of the above analysis, operating costs and provisions were assigned to gross transmission, as shown in line 1 of Table 9-1 and line 1 of Appendix A, Schedule 3.4, as follows:

- 34 per cent of the Integrated Planning Business Group operating costs;
- 20 per cent of the Capital Infrastructure Project Delivery Business Group operating costs;
- 25 per cent of the Operations Business Group operating costs;
- 19 per cent of the Materials Management Department operating costs; and
- 32 per cent of the Fleet Services Department operating costs.

Portions of the total costs allocated to gross transmission from the Integrated Planning, Capital Infrastructure and Project Delivery and Operations Business Groups are subsequently allocated to generation and distribution, as discussed in section 9.2.9 below.

As shown on line 1 of Table 9-1, the current operating costs and provisions allocation to gross transmission have increased by 5.8 per cent from fiscal 2019 RRA to fiscal 2020 plan. Operating costs are discussed in Chapter 5 and provisions are discussed in Chapter 8, section 8.11.

9.2.6 Costs Directly Assigned to Gross Transmission

9.2.6.1 Taxes

Taxes are directly assigned to the gross transmission function as shown on line 2 of Appendix A, Schedule 3.4. Taxes that are directly assigned to the gross transmission function also include taxes related to Generation Related Transmission Assets (**GRTA**) and to Substation Distribution Assets (**SDA**). To derive the taxes specific to the OATT Related Assets, taxes are further allocated through direct assignment and asset analysis. These taxes are included in the internal allocations to GRTA and to SDA on line 8 and line 11 of Appendix A, Schedule 3.4. As shown on line 2 of Table 9-1 and on line 26 of Appendix A Schedule 6.0, there has been a 7.1 per cent increase in the Taxes allocated to gross transmission from fiscal 2019 RRA to fiscal 2020 plan. Taxes are discussed in Chapter 8, section 8.6.

9.2.6.2 Amortization, Finance Charges and Return on Equity

Amortization, finance charges and return on equity are directly assigned to gross transmission and are shown on lines 3, 4 and 5, respectively of Appendix A, Schedule 3.4. Amortization, Finance Charges and Return On Equity are discussed in Chapter 8, sections 8.2, 8.3 and 8.5, respectively.

The amortization assigned to gross transmission includes amortization related to GRTA, SDA, OATT Related Assets and five per cent of demand-side management amortization. As approved by Order No. G-47-16,[340] demand-side management amortization is directly assigned to transmission. The remaining gross transmission amortization has been allocated to the functional activities using allocation factors derived from asset analysis. As shown on line 3 of Table 9-1 and on line 34 of

[340] In Order No. G-47-16, issued on March 31, 2016, the BCUC approved a Cost of Service Study and Rate Class Segmentation Negotiated Settlement Agreement, as part of BC Hydro's 2015 Rate Design Application. In section 8 on page 11 of the Negotiated Settlement Agreement appended to Order No. G-47-16, the negotiating parties agreed it was appropriate to functionalize five per cent of DSM costs to transmission, subject to BC Hydro revisiting the functionalization between generation, transmission and distribution in its fiscal 2019 Cost of Service Study.

Appendix A Schedule 7.0, there has been a 1.8 per cent increase in the current amortization cost allocation to gross transmission from fiscal 2019 RRA to fiscal 2020 plan.

The Finance Charges and Return On Equity assigned to gross transmission are allocated to the functional activities shown in Table 9-2 based on the average rate base for each fiscal year. As shown on line 4 of Table 9-1 and on line 38 of Appendix A Schedule 8.0, there has been a 16.9 per cent increase in the current Finance Charges allocated to gross transmission from fiscal 2019 RRA to fiscal 2020 plan. As shown on line 5 of Table 9-1 and on line 41 of Appendix A Schedule 9.0, there has been a 6.9 per cent decrease in the Return on Equity allocated to gross transmission from fiscal 2019 RRA to fiscal 2020 plan.

9.2.7 Business Support Cost Allocation

The current business support costs assigned to gross transmission are shown on line 6 of Appendix A, Schedule 3.4. As shown on line 6 of Table 9-1 and on line 44 of Appendix A, Schedule 3.1, there has been a 72.3 per cent increase in the current business support cost allocation to gross transmission from fiscal 2019 RRA to fiscal 2020 plan. Business support costs are discussed in Chapter 8, section 8.10.

Business support costs are allocated to the generation, transmission and, distribution functional activities shown in Table 9-2, using allocation factors derived from FTEs and activity analysis.

9.2.8 Internal Allocations to Transmission

The following costs are also assigned to transmission:

1. Generation operating costs relating to the generation ancillary services that BC Hydro provides to OATT customers, as shown on line 8 of Table 9-1 and on line 13 of Appendix A, Schedule 3.4;

2. Capitalized Overhead, as shown on and line 9 of Table 9-1 and on line 7 of Appendix A, Schedule 3.1; and
3. A one-time allocation associated with the write-off the balance of the Rate Smoothing Regulatory Account in fiscal 2019 forecast only, as shown on line 10 of Appendix A, Schedule 3.1. This is offset by a reduction in the allocation of Return on Equity, as shown on line 41 of Appendix A, Schedule 9.0.

These costs are functionalized directly to transmission and are not allocated further through the internal allocations from gross transmission, discussed in section 9.2.9 below.

9.2.9 Internal Allocations from Gross Transmission

Internal allocations from gross transmission are shown on lines 11 to 15 of Table 9-1 and on lines 8 to 11 of Appendix A, Schedule 3.4. These internal allocations are described below.

9.2.9.1 Generation Related Transmission Asset Allocation

By Letter No. L-92-07, the BCUC accepted that a fixed charge of $43.3 million was appropriate for Generation Related Transmission Asset costs, and that re-evaluations of Generation Related Transmission Asset costs were not required.

The $43.3 million internal allocation of Generation Related Transmission Asset costs from the transmission function to the generation function is shown on line 13 of Table 9-1 and on line 8 of Appendix A, Schedule 3.4.

9.2.9.2 Generation Real Time Dispatch

Generation real time dispatch activities performed by the T&D System Operations KBU include generation control, water conveyance, alarm monitoring, notification and reporting services, data services and Supervisory Control and Data Acquisition system services. These control centre activities support the operation of the generation and transmission systems. Manager interviews were conducted to derive the allocation of the total cost for this activity.

The overall determination of the Real Time Dispatch revenue requirement is required to establish the Scheduling and Dispatch rate for OATT Rate Schedule 03. These costs are assumed to be transmission costs for the purpose of determining the Scheduling and Dispatch rate. A portion is then allocated to generation, representing Generation Real Time Dispatch. The internal allocation of generation real time dispatch costs from the transmission function to generation is shown on line 14 of Table 9-1 and on line 9 of Appendix A, Schedule 3.4.

9.2.9.3 Distribution Real Time Dispatch

Distribution real time dispatch supports the operation of the distribution system, and includes activities performed by the control centre within the T&D System Operations KBU. This activity supports the operation of the distribution system from inside the substation fence, downstream of the high- side of the step down transformer, outside the substation fence, and also supports restoration of the distribution system outages. The cost for distribution real time dispatch includes costs for the restoration centre and an allocation of business support costs assigned to gross transmission and to the T&D System Operations KBU. Manager interviews were conducted to derive the allocation of the total cost for this activity.

Generation Real Time Dispatch costs are assumed to be transmission costs for the purpose of determining the Scheduling and Dispatch rate. A portion is then allocated to distribution, representing Distribution Real Time Dispatch. The internal allocation of distribution real time dispatch costs from the transmission function to distribution is shown on line 15 of Table 9-1 and on line 10 of Appendix A, Schedule 3.4.

9.2.9.4 Substation Distribution Asset Allocation

All substation assets, including distribution specific substation assets, are recorded as transmission property. Substations with both transmission and distribution functions include assets common to both functions, such as buildings and fences as well as heating, ventilation and air conditioning equipment.

The Substation Distribution Asset allocation is necessary to transfer the distribution-related portion of the substation costs, including an allocation of common assets, to the distribution function. To determine an appropriate share of gross transmission costs to allocate to Substation Distribution Assets, allocation factors are determined using asset analysis, maintenance, capital expenditures, manager interviews and direct assignment. The costs allocated to the Substation Distribution Asset functional activity include operating costs, capital related expenses, taxes and business support costs.

The internal allocation of Substation Distribution Asset costs from gross transmission to distribution is shown on line 16 of Table 9-1 and on line 11 of Appendix A, Schedule 3.4.

9.2.10 Miscellaneous Revenue

The miscellaneous revenue functionalized to transmission is shown on lines 17 to 22 of Table 9-1 and on line 7 of Appendix A, Schedule 3.4.

Miscellaneous revenue continues to be directly assigned to the transmission function, as shown on lines 4 to 9 of Appendix A, Schedule 15.0.

9.2.10.1 External OATT Revenue

External OATT revenue consists of revenue from external parties (i.e., parties other than BC Hydro and Powerex) for PTP Transmission Service and Ancillary Services such as Scheduling, System Control and Dispatch Service.

The forecast of total external OATT revenue is based on fiscal 2018 actual volumes, adjusted for known changes to long- term contracts. The forecast is summarized on lines 70 to 73 of Appendix A, Schedule 3.4, and reflected on line 4 of Appendix A, Schedule 15.0. External OATT revenue remains a component of the TRR and is not deducted from gross transmission costs in Table 9-1.

9.2.10.2 FortisBC General Wheeling Agreement

Wheeling is the transportation of electricity from one utility's service area to another's. Wheeling revenue is collected from FortisBC in accordance with the General Wheeling Agreement. The charges for the wheeling of electricity from the Point of Supply to the Creston, Okanagan and Princeton Points of Interconnection are set out in BC Hydro’s Rate Schedule 3817. In accordance with the General Wheeling Agreement, the forecast of wheeling revenue for the test period reflects annual rate increases equal to the forecast increases in the Consumer Price Index and expected increases in volumes, based on the nomination provided by FortisBC.

The forecast of wheeling revenue from FortisBC is shown on line 18 of Table 9-1 and on line 5 of Appendix A, Schedule 15.0.

9.2.10.3 Secondary Revenue

Secondary revenue is revenue received from external parties for the non-electric use of transmission assets, such as facility and digital communications site rentals.

The forecast of secondary revenue is shown on line 19 of Table 9-1 and on line 6 of Appendix A, Schedule 15.0.

9.2.10.4 Interconnection Revenue

Interconnection revenue consists of payments for engineering studies done by BC Hydro for generator and load interconnection customers connecting to the transmission system. Under the OATT, BC Hydro conducts engineering studies for customers requesting service, and the customers pay for the engineering studies.

The forecast of transmission interconnection revenue is shown on line 20 of Table 9-1 and on line 7 of Appendix A, Schedule 15.0.

9.2.10.5 Amortization of Contributions

Amortization of Contributions revenue relates to contributions from external parties toward the construction of capital assets.

The forecast of Amortization of Contributions revenue is shown on line 21 of Table 9-1 and on line 8 of Appendix A, Schedule 15.0. Details of the components of Amortization of Contributions are shown on Appendix A, Schedule 11, line 15 plus line 16, minus line 12.

9.2.10.6 Northwest Transmission Line Supplemental Charge

The costs to construct the Northwest Transmission Line are recovered from customers taking service on the line, in accordance with Electric Tariff Supplement No. 37. As the capitalized costs of the Northwest Transmission Line are a component of the gross transmission costs, they are offset by the amortized contributions from customers connected to the line.

The forecast Northwest Transmission Line Supplemental Charge revenue is shown on line 22 of Table 9-1 and on line 9 of Appendix A, Schedule 15.0.

9.3 OATT Rates are Set to Recover Transmission Revenue Requirements Consistent with Past Orders

The TRR is calculated by subtracting internal allocations and miscellaneous revenues (except external OATT revenue) from gross transmission and is recovered through BC Hydro's OATT rate schedules, for the following services:

1. Network Integration Transmission Service (**NITS**);
2. Point-To-Point (**PTP**)Transmission Service; and
3. Ancillary Services.

Approximately 1.5 per cent of the total TRR collected under the OATT is collected from customers external to BC Hydro and Powerex. As BC Hydro is the only NITS customer, the entire NITS rate, plus PTP and ancillary services used by BC Hydro, are ultimately recovered through BC Hydro's bundled service rates. Revenues from PTP services paid by Powerex reduce the revenue requirement to be recovered from the BC Hydro NITS service. Revenues from PTP and ancillary services used by external parties reduce the revenue requirement to be recovered through bundled service rates.

The calculation of the OATT rates is consistent with the design of the OATT rates previously approved by BCUC and the past practice of BC Hydro and BCTC.

9.3.1 Network Integration Transmission Service (NITS)

NITS is a flexible transmission service which allows the NITS customer to integrate, economically dispatch and regulate its designated generation resources to serve its designated loads, as well as deliver energy from non-designated generation resources on an as-available basis. This flexible use of the network to integrate resources and loads is different than PTP service, which is the reservation and transmission of capacity and energy on a firm or non-firm basis from point A to point B.

The NITS charge is designed to recover the TRR, less any revenues from PTP and Ancillary services, as illustrated in the following equation:

$$\text{Monthly NITS Charge} = \frac{\text{TRR} - (\text{PTP Revenue} + \text{Ancillary Services Revenue})}{12\ \text{months}}$$

The derivation of the monthly NITS charge is shown in Table 9-4 below.

Table 9-4 Calculation of Monthly NITS Charge

		Reference	F2017 RRA ($ million)	F2018 RRA ($ million)	F2019 RRA ($ million)	F2020 Plan ($ million)	F2021 Plan ($ million)
			1	2	3	4	5
1	**TRR**	Schedule 3.4 L28	**913.5**	**907.2**	**930.7**	**1,048.3**	**1,047.6**
2	**Less PTP and Ancillary Services Revenue:**						
3	PTP Revenue	Schedule 3.4 L69	(97.2)	(96.8)	(99.7)	(113.3)	(114.2)
4	Ancillary Service	Schedule 3.4 L35 to L38	(5.4)	(5.3)	(5.3)	(6.8)	(6.9)
5	**Total PTP and Ancillary Services Revenue**	L3+L4	**(102.6)**	**(102.1)**	**(105.0)**	**(120.0)**	**(121.1)**
6	**NITS Revenue Requirement**	Schedule 3.4 L32	**810.8**	**805.1**	**825.6**	**928.2**	**926.5**
7	**Monthly NITS Charge**	Schedule 3.4 L33	**67.6**	**67.1**	**68.8**	**77.4**	**77.2**

9.3.2 PTP Transmission Service

PTP service is the reservation and transmission of capacity and energy, on a firm or non-firm basis, from point A to point B, on the transmission system.

The PTP Service rate is designed to recover the cost of the TRR if PTP transmission service were used to transfer the maximum capacity supply on the system. In theory, if there were no NITS customer, the PTP charge would recover the TRR, less ancillary service revenue. Specifically, based on the approved rate design, the PTP Transmission Service rate is based on the following:

$$\text{PTP Rate} = \frac{\text{(TRR - Ancillary Services Revenue)}}{\text{(Maximum Capacity Supply)}}$$

The billing determinant for the long-term PTP Transmission Service rate is BC Hydro's Maximum Capacity Supply, which is BC Hydro's total dependable capacity including planned resources.

The derivation of the PTP Transmission Service rate is shown in Table 9-5 below.

Table 9-5 Calculation of the PTP Transmission Service Rate

		Reference	F2017 RRA ($ million)	F2018 RRA ($ million)	F2019 RRA ($ million)	F2020 Plan ($ million)	F2021 Plan ($ million)
			3	4	5	4	5
1	TRR	Schedule 3.4 L28	**913.5**	**907.2**	**930.7**	**1,048.3**	**1,047.6**
2	Less Ancillary Services	Schedule 3.4 L35 to L38	(5.4)	(5.3)	(5.3)	(6.8)	(6.9)
3	**Net TRR**	Schedule 3.4 L39	**908.1**	**901.9**	**925.4**	**1,041.5**	**1,040.7**
4	Maximum Capacity Supply (MW)	Schedule 3.4 L.40	12,978	13,124	13,115	13,279	13,279
5	Annual Billing Determinants (MW month)	L4 x 12 months	155,736	157,488	157,380	159,348	159,348
6	**PTP Rate ($/MW Month)**	L3 X 1,000,000/L5 = Schedule 3.4 L42	**5,830.86**	**5,726.62**	**5,879.58**	**6,536.12**	**6,531.23**

9.3.3 Ancillary Services

9.3.3.1 Scheduling, System Control and Dispatch

Scheduling, System Control and Dispatch services include:

- Pre-scheduling, Settlements and Billing - transactional processing through market operation and business systems to ensure accurate transmission schedules are confirmed for customers, followed by timely invoicing, accounting and performance reporting;
- Revenue Reporting and Forecasting - providing monthly and annual revenue reports for OATT services and provision of the historical information and forecasts for future years, as required for determination of revenue requirements and rate setting; and
- Real-Time Scheduling - managing the transmission reservations and energy schedules in real-time. Interchange Operators coordinate with Bonneville Power Administration and the Alberta Electric System Operator at least every hour to

match schedules and reach a net interchange schedule which is incorporated into the Automatic Generation Control system to maintain energy balance.

The Scheduling, System Control and Dispatch rate is a volume-driven rate, calculated as the total cost for Scheduling, System Control and Dispatch, divided by the total forecasted volumes for NITS, long-term PTP and short-term PTP services.

The derivation of the Scheduling, System Control and Dispatch rate is shown in Table 9-6 below.

Table 9-6 Calculation of Scheduling, System Control and Dispatch Rate

		Schedule Reference	F2017 RRA	F2018 RRA	F2019 RRA	F2020 Plan	F2021 Plan
			3	4	5	4	5
1	**PTP Volumes (MWh)**						
2	Long-Term PTP	Schedule 3.4 L51	9,355,680	9,355,680	9,355,680	9,881,280	9,881,280
3	Short Term PTP	Schedule 3.4 L60	10,052,378	10,480,466	10,908,554	9,939,991	10,324,607
4	**Total PTP Volumes**		19,408,058	19,836,146	20,264,234	19,821,271	20,205,887
5	NITS and Secondary Transmission		8,325,721	8,325,721	8,325,721	9,566,902	9,566,902
6	**Total Volumes**	**Schedule 3.4 L47**	27,733,779	28,161,867	28,589,955	29,388,173	29,772,789
7	**Scheduling, Control and Dispatch Cost ($ million)**	Schedule 3.4 L46	2.9	2.8	2.9	3.9	4.0
8	**Scheduling Fee[341] ($/MWh)**	**(L8/L7) =Schedule 3.4 L48**	0.105	0.100	0.100	0.133	0.136

9.3.3.2 Other Ancillary Services

BC Hydro provides ancillary generation services for OATT customers. Other ancillary services include energy imbalance service, loss compensation service, spinning and supplemental operating reserve services, and reactive power service.

[341] Scheduling, System Control and Dispatch rate.

The revenue from these other external ancillary services is shown on line 36 of Appendix A, Schedule 3.4.

9.4 PTP Revenue Forecast

The long-term PTP revenue is derived from the forecast long-term PTP volumes and the proposed long-term PTP rates. The forecasts of long-term PTP volumes are based on committed long-term transmission contracts.

The short-term PTP (including non-firm PTP) revenue forecast reflects the discounting of short-term PTP rates on export and wheel-through transactions. The applicable rates are $3.00/MWh during High (Heavy) Load Hours and $1.00/MWh during Low (Light) Load Hours, Sundays and North American Electricity Reliability Corporation (NERC) holidays. The forecast of external short-term PTP volumes are based on fiscal 2018 actual volumes. The internal short- term PTP volumes are based on the Energy Studies model, which is discussed further in Chapter 4, section 4.4.

Table 9-7 summarizes the forecast PTP revenue and volumes.

Table 9-7 Summary of Forecast PTP Revenue and Volumes

		Schedule Reference	F2017 RRA	F2018 RRA	F2019 RRA	F2020 Plan	F2021 Plan
			1	2	3	4	5
1	**PTP Revenue ($ million)**						
2	Long Term PTP	Schedule 3.4 L54	74.8	73.3	75.3	88.4	88.4
3	Short-Term PTP	Schedule 3.4 L63	22.5	23.4	24.4	24.8	25.8
4	**Total PTP Revenue**	**Schedule 3.4 L69**	97.3	96.7	99.7	113.3	114.2
5	**PTP Volumes (MWh)**						
6	Long-Term PTP	Schedule 3.4 L51	9,355,680	9,355,680	9,355,680	9,881,280	9,881,280
7	Short Term PTP	Schedule 3.4 L60	10,052,378	10,480,466	10,908,554	9,939,991	10,324,607
8	**Total PTP Volumes**		19,408,058	19,836,146	20,264,234	19,821,271	20,205,887
9	**PTP Average Price ($/MWh)**						
10	Long Term PTP	Schedule 3.4 L57	7.99	7.84	8.05	8.95	8.95
11	Short Term PTP	Schedule 3.4 L66	2.24	2.24	2.24	2.50	2.50

9.5 Proposed OATT Rates

Table 9-8 summarizes the proposed OATT rates. Overall, there is an 11.1 per cent increase in the long-term PTP rate between fiscal 2019 RRA and fiscal 2020 plan. This is due to the increase in allocated costs to the TRR, as discussed above. As the billing determinant in line 5 of Table 9-5 has increased by only 1.2 per cent over this same period, the increase to the TRR results in an increase in the undiscounted PTP service rates.

BC Hydro believes that the proposed OATT rates, which reflect the TRR and are derived through an established methodology, are just and reasonable and should be approved as sought.

Table 9-8 Proposed OATT Rates
Fiscal 2020 to Fiscal 2021

	Rate Schedule	Rate Class	Reference	F2020 Plan	F2021 Plan
				1	2
1	Attachment H	**NITS Revenue Requirement ($)**	Schedule 3.4 L32	928,236,000	926,484,000
2	RS 00	**NITS Monthly Rate ($)**	Schedule 3.4 L33	77,353,000	77,207,000
3	RS 01	**Long Term Firm Point-to-Point**			
4		Yearly - $/MW of Reserved Capacity per year	Schedule 3.4 L41	78,433	78,375
5		**Short Term Firm and Non-Firm Maximum Price for Delivery**			
6		Monthly - $/MW of Reserved Capacity per month	Schedule 3.4 L42	6,536.12	6,531.23
7		Weekly - $/MW of Reserved Capacity per week	Schedule 3.4 L43	1,508.34	1,507.21
8		Daily - $/MW of Reserved Capacity per day	Schedule 3.4 L44	214.89	214.73
9		Hourly - $/MW of Reserved Capacity per hour	Schedule 3.4 L45	8.95	8.95
10	RS 03	**Scheduling, System Control and Dispatch Service ($)**			
11		per MW of Reserved Capacity per hour	Schedule 3.4 L48	0.133	0.136

Fiscal 2020 to Fiscal 2021

Revenue Requirements Application

Chapter 10

Demand-Side Management

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10.1 Introduction

In this chapter, BC Hydro sets out the information and analysis in support of our proposed fiscal 2020 to fiscal 2021 demand-side measures expenditure schedule. We are requesting that the BCUC accept this schedule under section 44.2 of the *Utilities Commission Act*. The proposed expenditure schedule includes expenditures on demand-side measures that we anticipate making over the fiscal 2020 to fiscal 2021 test period. This includes expenditures on the thermo-mechanical pulp program.[342]

In addition to the proposed demand-side measures expenditure schedule, BC Hydro anticipates expenditures on low-carbon electrification undertakings over the same period.[343] BC Hydro requests that these expenditures be deferred to the Demand Side Management (**DSM**) Regulatory Account, consistent with the Direction to the BCUC Respecting Undertaking Costs (B.C. Reg. 77/2017). The expenditures for low-carbon electrification undertakings are presented together with expenditures for demand-side measures as all of these expenditures will help customers manage their energy use and are considered part of BC Hydro's overall demand-side management.

Our proposed demand-side measures expenditure schedule responds to the BCUC's Decision on our Previous Application by increasing expenditures for the residential sector by approximately 50 per cent and providing a new program for customers in Non-Integrated Areas, while staying within a similar overall portfolio spending envelope. It also continues our moderation approach, providing broad customer access to conservation and energy management opportunities and

[342] Expenditures for the Thermo-Mechanical Pulp program are shown separately, since the costs of this program are covered by the Direction to the British Columbia Utilities Commission Respecting the Authority's TMP Program (B.C. Reg. 139/2015). A copy of this direction is provided in Appendix D.

[343] Expenditures for low-carbon electrification undertakings are shown separately, since these costs are covered by the Direction to the British Columbia Utilities Commission Respecting Undertaking Costs (OIC 100/2017) and the Greenhouse Gas Reduction Regulation (B.C. Reg. 102/2012) as amended by OIC 101/2017. In this application, BC Hydro is requesting confirmation of the deferral treatment of low-carbon electrification expenditures. Copies of the low-carbon electrification directions are provided in Appendix D.

managing the overall level of expenditures to limit forecast rate increases while BC Hydro is in an energy surplus.

The expenditures associated with demand-side measures as well as expenditures for low-carbon electrification are shown in Table 10-1 below.

Table 10-1 Fiscal 2020 to Fiscal 2021 Demand-Side Measures Expenditure Schedule and Low-Carbon Electrification Expenditures

	Expenditure ($ million)
Fiscal 2020 Demand-Side Measures	90.8
Fiscal 2021 Demand-Side Measures	89.1
Thermo-Mechanical Pulp (Fiscal 2020-Fiscal 2021)	27.2[344]
Two-Year Total (for section 44.2 acceptance)	**207.1**
Low-Carbon Electrification (Fiscal 2020-Fiscal 2021)	28.0
Two-Year Total (including Low-Carbon Electrification)	**235.1**

The Fiscal 2020 to Fiscal 2022 Demand Side Management Business Plan,[345] provided as Appendix X, provides details on the demand-side measures initiatives and expenditures, including the thermo-mechanical pulp program. Details on our low-carbon electrification undertakings are provided in Appendix Y.

The remainder of this Chapter is organized around the following key points:

- Section 10.2 reviews the outcomes of the fiscal 2017 to fiscal 2019 traditional DSM initiatives and low-carbon electrification undertakings and BC Hydro's response to directives from the Previous Application.
- Section 10.3 explains that BC Hydro is complying with the regulatory and legislative framework applicable to BC Hydro's traditional DSM and low-carbon electrification expenditures.

[344] All expenditures related to Thermo-Mechanical Pulp are forecasted to occur in fiscal 2021.

[345] BC Hydro's DSM business plans are developed on an annual basis, covering a rolling three-year period. This provides continuity for the planning and implementation of DSM activities. The DSM expenditure request supported in this chapter covers the first two years of the Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan, aligning with the test period of this Revenue Requirements Application.

- Section 10.4 presents BC Hydro's approach for determining the level of expenditures during the test period.
- Section 10.5 presents an overview of BC Hydro's expenditures over the test period, the anticipated energy and capacity impacts as well as the cost-effectiveness and other benefits of the plan. This section also sets outs BC Hydro's request to revise the approach to allocating portfolio-level costs to programs, provides evidence on the persistence of DSM savings and describes how BC Hydro has re-categorized its energy management activities into a new program called Energy Management Activities within each sector.
- Section 10.6 demonstrates that BC Hydro manages the performance of the plan in a comprehensive manner, including tracking a number of performance metrics and regular management oversight and reporting.

10.1.1 Overview of DSM

Figure 10-1 below shows the various components of BC Hydro's demand-side management. As a concept, DSM can refer to any of these components. In this application, BC Hydro has defined DSM as including each of the components shown below.

Figure 10-1 Demand Side Management Components

Historically, industry efforts have focused on energy efficiency and conservation as well as capacity-focused initiatives, which BC Hydro refers to as “traditional DSM.” These traditional DSM programs are a low cost resource that help to lower utility costs for customers, and support multiple *Clean Energy Act* energy objectives. In addition to being an energy resource, BC Hydro’s DSM initiatives engage customers, help them save money on their bills and enhance BC Hydro’s relationships with customers and stakeholders. DSM also improves the competitiveness of commercial and industrial customers by reducing their operating costs and helps to create jobs and other economic benefits. In addition, BC Hydro’s capacity-focussed DSM initiatives identify opportunities to learn how to reduce capacity constraints on the grid. The adequacy and cost-effectiveness of traditional DSM is subject to the Demand-Side Measures Regulation. A copy of this regulation is provided in Appendix D.

As of fiscal 2018, BC Hydro’s DSM initiatives also include low-carbon electrification undertakings aimed at reducing greenhouse gas (**GHG**) emissions by encouraging consumers to switch from higher carbon sources of energy to electricity. These initiatives are included to provide a complete picture of BC Hydro’s DSM initiatives.

All of our DSM initiatives help customers manage their electricity consumption. Where appropriate, low-carbon electrification undertakings are administered with our existing DSM programs to achieve efficiencies and make it easy for customers. The regulatory treatment and cost-effectiveness metrics for low-carbon electrification are set out under the Greenhouse Gas Reduction Regulation. A copy of this regulation is provided in Appendix D. Low-carbon electrification undertakings are described further in section 10.4.3 and in Appendix Y.

10.1.2 Overview of our DSM Plan

Consistent with BC Hydro's approach in the Previous Application, the DSM Plan continues the moderation approach for traditional DSM as discussed in section 10.4.1. The moderation approach is designed to be a cost-effective strategy given BC Hydro's current energy surplus. The average portfolio utility cost of the DSM Plan is less than the market price of export electricity. This means that the DSM Plan provides a net benefit for customers by reducing our overall revenue requirements.

While the funding envelope and programs for traditional DSM remain similar to the DSM Plan presented in the Previous Application, BC Hydro has made modifications to its DSM programs in response to BCUC directives, the Government of B.C.'s priorities around affordability and changes in the Demand-Side Measures Regulation. These program changes have resulted in increased expenditures for the residential sector, while staying within the overall portfolio spending envelope.

Specifically, BC Hydro has taken steps to increase participation in our Low Income program, expanded the Home Renovation Rebate program, and launched a new Non-Integrated Areas program through a re-allocation of expenditures from the commercial and industrial sectors. In addition, to be consistent with a recent change in the Demand-Side Measures Regulation, we have also re-categorized our energy management activities into a new program called Energy Management Activities for each sector.[346] We have also reviewed industry practice on codes and standards attribution and made some changes to improve the presentation of codes and standards savings in our DSM Plan. These program and initiative modifications are discussed further in section 10.4.4.

Capacity-focussed pilots and trials will also continue over the next two years. This is described further in section 10.4.2.

10.2 Fiscal 2017 to Fiscal 2019 DSM Results and Response to BCUC Directives

Over the past three years, we have continued the implementation of traditional DSM initiatives, including exploration of capacity-focussed initiatives, while starting to advance low-carbon electrification undertakings. We have achieved our traditional DSM targets for those years, and have addressed the BCUC's directives from our Previous Application. BC Hydro's expenditures on low carbon electrification undertakings were consistent with the requirements set out under the Greenhouse Gas Reduction (Clean Energy) Regulation (B.C. Reg. 102/2012).

10.2.1 Results and Achievements from Fiscal 2017 to Fiscal 2019

Table 10-2 and Table 10-3 below provide the savings and electrification results and associated expenditures compared to plan values for fiscal 2017 to fiscal 2019. In Table 10-2, the Plan Values represent the planned amounts described in BC Hydro's Previous Application, and accepted by the BCUC. Actual results represent the results that were actually achieved. Energy savings and new incremental capacity have been achieved through a combination of codes and standards,[347] rate structures, and programs.

[346] In March 2017, the B.C. Government revised the Demand-Side Measures Regulation to add an Energy Management Program category. To align with this change, BC Hydro has re-categorized relevant activities and expenditures into this new category. This re-categorizing did not result in any expenditure changes for those activities or any changes to the overall Plan budget.

[347] Cost-effectiveness metrics within this application will exclude the impact of codes and standards savings. See section 10.2.3 for further discussion.

Table 10-2 Traditional DSM Incremental Savings and Expenditures[348]

	New Incremental Energy Savings (GWh/year)		New Incremental Associated Capacity Savings (MW)		Expenditures ($ million)	
	Plan Values	**Actual**	**Plan Values**	**Actual**	**Plan Values**	**Actual**
F2017	701	772	131	132	113.7	97.4
F2018	621	719	111	127	119.5	82.3
F2019	736	TBD	123	TBD	127.9	TBD

Table 10-3 Low-Carbon Electrification Incremental Load and Expenditures

	New Incremental Load (GWh/year)		New Incremental Associated Capacity Load (MW)		Expenditures ($ million)	
	Plan Values	**Actual**	**Plan Values**	**Actual**	**Plan Values**	**Actual**
F2017	n/a	n/a	n/a	n/a	n/a	n/a[349]
F2018	n/a	n/a	n/a	n/a	n/a	0.22
F2019	110	TBD	16	TBD	9.4	TBD

A full reporting of the historical energy impacts and expenditures is provided in Appendix Z for traditional DSM and Appendix BB for the low-carbon electrification undertakings.

10.2.2 BC Hydro Has Increased Residential Initiatives

In Directive 21 of its Decision on our Previous Application, the BCUC recommended that BC Hydro consider more targeted DSM programs directed at residential

[348] Values are new incremental savings in each year, rather than net savings. In previous applications, net savings (new incremental savings minus persistence drop-off) were presented. Using new incremental Plan and Actual savings values, better aligns with the new incremental expenditures being made each year. This approach is also consistent with BC Hydro's Service Plan goals.

[349] Approximately $0.2 million of the actual Fiscal 2017 DSM expenditures shown in Table 10-2 was spent on initial exploration of low carbon electrification initiatives, as noted in BCUC IR 2.323.2 of the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application proceeding.

customers. This directive arose from a concern over "the relatively low level of DSM spending for residential customers (including low-income customers)".[350]

In response, BC Hydro has increased expenditures for the residential sector and non-integrated areas in the DSM Plan for fiscal 2020 and fiscal 2021, while staying within the overall portfolio spending envelope. Compared to the plan presented in the Previous Application, expenditures targeted at the residential sector have increased by approximately 50 per cent. As a result of these increased residential expenditures, the overall program spending allocated to the residential sector has improved. This is shown in Table 10-4 below.[351]

Table 10-4 DSM Program Spend by Sector

	Residential (including low income) (%)	Commercial and light industrial[352] (%)	Large Industrial (%)
BC Hydro percentage of DSM program spend by sector (excluding Thermo-Mechanical Pulp program)			
F2014 to F2016 Actual	17	51	32
F2017 to F2018 Actual and F2019 Forecast	19	57	24
F2020 to F2021 Forecast	30	38	32
BC Hydro Allocation of DSM costs for cost recovery purposes			
Allocation of DSM costs	40	35	25

Participation targets for the Low Income Program have also been increased, with revised criteria and new measures introduced to allow more homes to qualify. In addition, BC Hydro has pre-qualified community events for Energy Saving Kit

350 BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 81.

351 Capacity-focused pilots are excluded from the calculations.

352 DSM to the light industrial sector has been delivered through the Power Smart Partners – Distribution and the Leaders in Energy Management – Distribution offers. Accordingly, expenditures for those offers have been re-allocated to the Commercial and light industrial column. Likewise, for the fiscal 2020 to fiscal 2021 Forecast, distribution customer expenditures have been re-allocated from the Leaders in Energy Management – Industrial offer. These allocations are consistent with the allocations in BC Hydro's Fully Allocated Cost of Service (**FACOS**).

distribution. Lastly, outreach through BC Hydro's Crisis Fund has also included steps to increase awareness of the Low Income Program with potential participants.

The Home Renovation Rebate Program has been augmented with additional measures and increased incentives. In addition, a new program for customers living in non-integrated areas of BC Hydro's service territory has been launched. Further details on these residential programs can be found in section 5 of Appendix X.

10.2.3 BC Hydro Has Reviewed Industry Practice for Codes and Standards Attribution

In Directive 22 of its Decision on our Previous Application, the BCUC directed BC Hydro to review if its approach for attributing savings that occur from the implementation of codes and standards was consistent with industry practice. This directive arose from a concern that the cost-effectiveness results for codes and standards could be over-stated or that other program cost-effectiveness results could be understated.[353]

In response, BC Hydro commissioned an assessment of the industry practice for attributing savings that occur from the implementation of codes and standards. The resulting report by the Cadmus Group is attached as Appendix CC. The report concluded that industry practice regarding codes and standards attribution is varied and evolving and that the different approaches stem from different regulatory and business drivers facing utilities. Approaches include:

- Not quantifying, nor attributing, any savings from codes and standards;
- Quantifying savings from codes and standards to reflect their impact on load forecasts and revenue requirements, without determining the portion of those savings that should be 'attributed' to the utility;

[353] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), pages 81 to 82.

- Attributing a portion of the savings from codes and standards to utility efforts, with the common approach being to attribute those savings to a stand-alone utility "Codes and Standards" program.[354] This differs from the Demand Side Measures Regulation approach, which is to attribute a portion of the codes and standards benefits directly to an individual incentive program (i.e., new construction), impacting the program's cost-effectiveness but not the energy savings claimed by that program.

Based on the Cadmus Group report, BC Hydro has taken the following steps to improve the presentation of our treatment of codes and standards savings in this application:

- First, we have excluded codes and standards savings from benefit-cost calculations and levelized costs. This means that those results are not distorted at the portfolio level by the codes and standards savings; and
- Second, BC Hydro is not attributing codes and standards savings to individual programs. Instead, codes and standards savings are presented as a stand-alone bucket of energy and associated capacity savings, separate from programs. BC Hydro is not claiming these savings (or a portion of them) as a credit towards DSM cost effectiveness calculations. Rather, a forecast of codes and standards savings is provided and incorporated into BC Hydro's Load Forecast. As shown in the Cadmus report, this aligns with the approach taken in the two Canadian jurisdictions (Ontario and Manitoba).

While BC Hydro has specific activities that directly support the achievement of codes and standards savings, we have chosen not to quantify that contribution through a formal attribution claim at this time. The time and effort required to assess and defend an attribution claim is not necessary, since all of our traditional DSM

[354] Rather than quantify and defend an attribution amount, BC Hydro's approach has been to determine what level of attribution would be required to make our codes and standards expenditures cost-effective. A savings attribution of approximately 1 per cent would result in the utility expenditures being deemed cost-effective.

initiatives are already cost effective. However, BC Hydro does have extensive codes and standards support activities as outlined in section 9 of Appendix X. In addition, many of BC Hydro's DSM programs help to prime the marketplace for the introduction of codes and standards.

10.2.4 BC Hydro Has Increased Activities in Non-Integrated Areas

In Directive 23 of its Decision on our Previous Application, the BCUC directed BC Hydro to include a line item in our Annual Report on DSM Activities to reflect the non-integrated areas activities that are tracked separately.[355] This directive was implemented starting with the F2018 Annual Report. This report is provided in Appendix Z.

Directive 23 also directed BC Hydro to include the following in its next DSM application:

- An update of how BC Hydro has addressed the DSM concerns raised above by Non-Integrated Areas Ratepayers Group (**NIARG**) and Zone II Ratepayers Group (**Zone II**) regarding the non-integrated areas; and
- An estimate of the difference in cost-effectiveness test results of programs available to customers in the non-integrated areas compared to the integrated areas.[356]

During the Previous Application proceeding, NIARG and Zone II submitted that BC Hydro should address opportunities in the non-integrated areas given the unique geographic and market barriers to participation and so that those communities benefit from DSM expenditures.

In response, BC Hydro has recently launched a new Non-Integrated Areas program to increase support for these remote and predominantly Indigenous communities.

[355] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), pages 82 to 84.

[356] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), pages 82 to 84.

This program is described in section 5.5 of Appendix X. The design and development of this program was informed by pilot work activities that were undertaken from fiscal 2017 to fiscal 2019. In addition, BC Hydro committed to further engagement with NIARG and Zone II and indigenous communities in general. BC Hydro engaged both NIARG and Zone II through its Low Income Advisory Council[357] and continues to work with indigenous communities on the specific issues and barriers they face with respect to conservation and energy management.

An estimate of the difference in cost-effectiveness test results of programs available to customers in the non-integrated areas compared to the integrated areas is provided in Table 10-5 below. The DSM cost-effectiveness tests and how to interpret results are described in section 10.5.3. While the net levelized cost of the Non-Integrated Areas program is higher than the integrated system programs, there is a higher avoided cost of energy for the Non-Integrated Areas due to on the cost of diesel generation. Both the Non-Integrated Areas program and the integrated systems programs have positive benefit-cost ratios.

Table 10-5 Cost Effectiveness Comparison of Non-Integrated Areas and Integrated System Programs

	Net Levelized Cost (non-integrated areas) ($/MWh)	Benefit-Cost Ratio (non-integrated areas)	Net Levelized Cost (integrated system programs ($/MWh)	Benefit-Cost Ratio (integrated system programs)
Utility Cost	175	1.8	11	1.7
Total Resource Cost	117	2.2	-11	3.6

[357] Consultation through this group was encouraged by the BCUC in their Decision on BC Hydro's Fiscal 2017 to Fiscal 2019 Revenue Requirements Application.

10.3 DSM Aligned with Legal and Regulatory Frameworks

This section describes the relevant legal and regulatory framework for traditional DSM and low-carbon electrification undertakings. It also identifies how BC Hydro's DSM initiatives are aligned with these requirements.

10.3.1 BC Hydro's Traditional DSM Complies with the Framework under Section 44.2 of the Utilities Commission Act

BC Hydro is requesting that the BCUC accept our proposed fiscal 2020 to fiscal 2021 demand-side measures expenditure schedule under section 44.2 of the *Utilities Commission Act*.

Under section 44.2 of the *Utilities Commission Act*, the BCUC must accept an expenditure schedule if it considers that making the expenditures would be in the public interest. Otherwise, the BCUC must reject the schedule. Alternatively, the BCUC may accept or reject a part of the expenditure schedule. However, section 44.2 does not provide the Commission with the authority to direct BC Hydro to file a DSM expenditure schedule, make additions to a DSM expenditure schedule, or change the design of a particular DSM program.

Section 44.2 sets out the factors that the BCUC must consider when deciding whether to accept a demand-side measures expenditure schedule filed by a public utility. Specifically, the BCUC must consider:

- The interests of persons in British Columbia who receive or may receive service from BC Hydro;
- British Columbia's energy objectives as set out in section 2 of the *Clean Energy Act*;
- An applicable Integrated Resource Plan approved under section 4 of the *Clean Energy Act*; and

- The extent to which the demand-side measures are cost-effective within the meaning prescribed by the Demand-Side Measures Regulation.[358]

BC Hydro's traditional DSM supports each of these factors as discussed below.

10.3.1.1 Traditional DSM Is in the Interest of Persons who Receive or May Receive Service

This Application demonstrates that our proposed traditional DSM expenditures are in the interests of persons in B.C. who receive or may receive service from BC Hydro. For instance, BC Hydro's proposed expenditures reflect a broad and cost effective range of demand-side management initiatives that provide significant energy savings and capacity benefits and provide customers with the opportunity to save electricity and lower their bills, while reducing BC Hydro's revenue requirements.

10.3.1.2 Traditional DSM Supports Energy Objectives

A summary of how BC Hydro's proposed DSM Plan supports the applicable energy objectives in the *Clean Energy Act* is provided in Table 10-6 below:

Table 10-6 DSM Plan Alignment with BC Energy Objectives

Energy Objective	DSM Plan
To achieve electricity self-sufficiency	The DSM Plan's forecast energy and capacity savings will contribute to BC Hydro maintaining electricity self-sufficiency in 2020 and in each year thereafter.
… reducing its expected increase in demand for electricity by the year 2020 by at least 66 per cent	The DSM Plan is forecast to reduce BC Hydro's increase in electricity demand by the end of fiscal 2021 by approximately 103 per cent.
To use and foster the development of innovative technologies that support energy conservation	Both DSM programs and the Codes and Standards initiatives will use and foster the development of innovative technologies supporting energy conservation. Refer to Appendix X for more detail.

[358] B.C. Reg. 326/2008 (Ministerial Order M271), B.C. Reg. 228/2011 (Ministerial Oder M335), B.C. Reg. 141/2014 (Ministerial Order M233) and B.C. Reg. 117/2017 (Ministerial Order M138). A copy is provided in Appendix D.

Energy Objective	DSM Plan
To ensure that BC Hydro's rates remain among the most competitive	The moderation strategy outlined in section 10.4.1 reduces rates relative to the DSM investment level for fiscal 2020 to fiscal 2021 that was contemplated in the 2013 Integrated Resource Plan.
To reduce B.C. GHG emissions	Customers in some DSM programs are forecasted to reduce their natural gas usage along with their electricity usage. The new Non Integrated Areas Program is also expected to reduce GHG emissions by reducing diesel generation. Reductions of 5,000 tonnes of CO2e/year are forecasted to result from traditional DSM.
To encourage communities to reduce GHG emissions and use energy efficiently	BC Hydro's Codes and Standards initiatives provide support to communities (including Indigenous communities) to incorporate electricity efficiency into community energy planning and implement energy efficiency policies and projects.
To encourage economic development and the creation and retention of jobs	BC Hydro's current DSM efforts create significant economic activity and jobs within the province, estimated at 11,600 person-years of employment over the next 10 years.

10.3.1.3 Traditional DSM Continues Moderation Approach Consistent with the 2013 Integrated Resource Plan

The selected level of DSM expenditures continues a moderation approach that was recommended in the 2013 Integrated Resource Plan (**IRP**) for fiscal 2014 to fiscal 2016. This moderation strategy was subsequently continued for fiscal 2017 to fiscal 2019 in response to an extended energy surplus and to limiting forecast rate increases. The BCUC found that the moderation approach was a balanced response to these circumstances and accepted BC Hydro's proposed expenditure schedule.[359] In this application, BC Hydro has continued the moderation approach given the ongoing energy surplus and to limit forecast rate increases. The proposed expenditure schedule continues to provide customers with broad opportunities to save electricity and reduce their bills. It also continues to meet the target set out in the *Clean Energy Act* and supports government priorities. Lastly, it maintains the

[359] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 78.

ability to ramp up DSM activities in the future in response to the next IRP or the Government of B.C.'s CleanBC Plan.

10.3.1.4 Traditional DSM Meets Adequacy Requirements Under the Demand-Side Measures Regulations

As discussed in Chapter 2, section 2.2.2, Government intends to propose amendments to the *Hydro and Power Authority Act* and the *Clean Energy Act* so that section 44.1 of the *Utilities Commission Act* applies to BC Hydro.

The proposed application of section 44.1 of the *Utilities Commission Act* to BC Hydro would require BC Hydro's demand-side measures to meet the adequacy requirements set out in the Demand-Side Measures Regulation under the *Utilities Commission Act*. These adequacy requirements set out the measures that a demand-side management portfolio must include in order to be considered adequate. While BC Hydro is not currently required to meet these adequacy requirements, our demand-side management plans have been consistent with them. Table 10-7 below shows how BC Hydro's traditional DSM aligns with the adequacy requirements set out in the Demand Side Measures Regulation.

Table 10-7 Traditional DSM Alignment with Adequacy Requirements in the Demand-Side Measures Regulation

Adequacy Requirements	DSM Plan
Demand-side measure for low income households	BC Hydro's Low Income Program assists residents of low income households, low-income housing providers, and Indigenous communities with reducing their energy consumption. Annual funding has been increased compared to the fiscal 2017 to fiscal 2019 period. A further description of this offer is provided on page 30 of Appendix X.
Demand-side measure for rental accommodations	BC Hydro offers a combination of programs that are available to rental accommodations. Renters with BC Hydro accounts participate in our Team Power Smart offer which helps to develop energy efficient behaviours. Renters also represent a significant portion of the participants in our Low Income program. Over the past two years, approximately 35 per cent of Energy Savings Kit participants have been renters and approximately 75 per cent of Energy Conservation Assistance Program participants have been renters. Renters also participate in our Retail program, purchasing products such as appliances and lighting technologies. These initiatives are contained within our residential sector initiatives, described on page 29 of Appendix X.
An education program for schools	Our Public Awareness Supporting Initiative provides school education programs across the province to engage teachers and students. This initiative is described on page 80 of Appendix X.
An education program for post-secondary institutions	BC Hydro partners with post-secondary institutions and industry associations who develop and deliver new training and education programs. This partnership is delivered through our Commercial Energy Management activities, described on page 54 of Appendix X.
Financial or other resources provided to support development of or compliance with standards	BC Hydro supports the development of and compliance with standards through its Codes and Standards initiatives, described on page 74 of Appendix X. The Demand-Side Measures Regulation requires expenditures in this area to be either an average of 1 per cent of a public utility's plan portfolio's expenditures per year or an average of $2 million per year. BC Hydro's DSM Plan meets this requirement. Annual expenditures of $5.2 million are planned to support governments, standards-making bodies, and regulatory bodies in the development and compliance of codes and standards.
Demand-side measures to support adoption of step codes by local government and first nations	BC Hydro supports the adoption of step codes through its Codes and Standards initiatives, described on page 74 of Appendix X.

10.3.1.5 Traditional DSM Is Cost-Effective Under the Demand-Side Measures Regulation

BC Hydro's expenditures for traditional DSM are cost-effective under the Utility Cost Test and the Total Resource Cost Test as prescribed by section 4 of the Demand-Side Measures Regulation. Refer to section 10.5.3 for more information.

10.3.2 Recovery of BC Hydro's Thermo-Mechanical Pulp Expenditures Is Required by Direction

BC Hydro's Thermo-Mechanical Pulp Program provides funding to increase the electrical efficiency of mills that use thermo-mechanical pulping processes. Expenditures for this program are made under the Direction to the BCUC Respecting the Authority's TMP Program.[360] This direction requires the BCUC to allow BC Hydro to recover up to $100 million in costs incurred to carry out the program. Further, the Direction requires the BCUC to allow BC Hydro to defer these costs to the Demand Side Management Regulatory Account. Due to this direction, our demand-side measures expenditure schedule lists Thermo-Mechanical Pulp Program expenditures separately.

10.3.3 Regulatory Framework for Low-Carbon Electrification

Section 18 of the *Clean Energy Act* requires the BCUC to allow BC Hydro to collect sufficient revenue to recover costs incurred for prescribed undertakings. Section 4 of the Greenhouse Gas Reduction Regulation (B.C. Reg. 102/2012) (**GGRR**), issued under the *Clean Energy Act*, defines a number of classes of electrification prescribed undertakings.

This section refers to BC Hydro's undertakings that fall within one or more classes defined in sections 4(3)(a), 4(3)(b), 4(3)(c), and 4(3)(d) of the GGRR, which are further described in Appendix Y. Undertakings are in a class of undertakings defined in subsections 4(3)(a) to 4(3)(b) of the GGRR if they satisfy a cost-effectiveness test defined in subsection 4(1) of the GGRR.

[360] A copy of the Direction to the BCUC respecting the Authority's TMP Program is included in Appendix D.

A Direction to the BCUC Respecting Undertaking Costs, issued under section 3 of the *Utilities Commission Act* (B.C. Reg. 77/2017), requires the BCUC to allow BC Hydro to defer the costs incurred for prescribed undertakings to the DSM Regulatory Account. In this application, BC Hydro is requesting BCUC approval to defer low carbon electrification expenditures to the DSM Regulatory Account.

BC Hydro's low-carbon electrification undertakings also support the B.C. Energy Objectives as outlined in Table 10-8.

Table 10-8 Low-Carbon Electrification Plan Alignment with BC Energy Objectives

Energy Objective	Low-Carbon Electrification Plan
To ensure that BC Hydro's rates remain among the most competitive	The incremental revenue from low-carbon electrification undertakings reduces forecast rate increases.
To reduce B.C. GHG emissions	BC Hydro's planned low-carbon electrification undertakings are forecast to result in natural gas and other fossil fuel savings. These savings will reduce B.C. GHG emissions by approximately 350,000 tonnes of CO^2e/year.
To encourage the switching from one kind of energy source or use to another that decreases GHG emissions in B.C.	BC Hydro's planned low-carbon electrification undertakings are focused on reducing GHG emissions.
To encourage economic development and the creation and retention of jobs	BC Hydro's planned low-carbon electrification undertakings create economic activity and jobs within the province.

10.4 Overall Level of Fiscal 2020 to Fiscal 2021 DSM Expenditures Reflects a Reasonable and Balanced Approach

This section sets out how BC Hydro determined a reasonable and balanced level of forecast fiscal 2020 and fiscal 2021 expenditures for traditional DSM and low-carbon electrification.

10.4.1 Moderation Approach Remains Appropriate

BC Hydro has maintained its moderation approach to energy efficiency and conservation as outlined in the Previous Application. In its Decision, the BCUC determined that this moderation approach provided "a balanced response to a reduction in the load forecast and the need to meet certain targets under the 2013 10 Year Rates Plan." [361]

The reasons for the moderation approach that were described in the Previous Application continue to exist. BC Hydro remains in an energy surplus position and we continue to manage upward pressure on rates to limit forecast rate increases.

The moderation approach means that the DSM Plan maintains the overall funding envelope for DSM. However, changes have been made within this funding envelope. For example, to increase expenditures in the residential sector in response to recommendations from the BCUC, BC Hydro reduced expenditures in other sectors. The proposed expenditure schedule provides customers with broad opportunities to save electricity and reduce their bills. It also continues to meet the target set out in the *Clean Energy Act* and supports government priorities. Lastly, it maintains the ability to ramp up DSM activities in the future in response to the next IRP or the Government of B.C.'s CleanBC Plan.

To develop the DSM Plan for fiscal 2020 and fiscal 2021, consistent with this moderation strategy, BC Hydro used the forecast market price for electricity exports ($30/MWh) as a screening filter for the utility cost of non-specified DSM programs. Specified programs required by the Demand-Side Measures Regulation were not subject to this requirement. This market priced screening filter was also used to develop the proposed DSM expenditure schedule in the Previous Application. In its Decision, the BCUC found that "given the energy surplus situation, the use of a market priced screening filter to identify cost-effective DSM is reasonable."[362]

The use of a market priced screening filter means that all non-specified programs within the DSM Plan contribute to a reduction in BC Hydro's overall revenue

[361] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 78.

[362] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 78.

requirements while BC Hydro is in an energy surplus. This is because the energy savings from the DSM program are less than the price BC Hydro could receive on the market for any resulting surplus energy.

Maintaining the moderation strategy also allows future decisions on the level of demand side management to be informed by BC Hydro's next IRP and the Government's CleanBC Plan. As explained in Chapter 2, section 2.2.2, BC Hydro's next IRP will be submitted to the BCUC by February 28, 2021.

BC Hydro's next IRP will consider a recently completed Conservation Potential Review. BC Hydro worked with FortisBC Energy Inc., FortisBC Inc., Pacific Northern Gas and Navigant Consulting Ltd. to perform the review. The review estimated the technical and economic conservation potential for both electricity and natural gas in B.C., over the next 20 years, in each utility's service territory. In addition, it provided a model that allows BC Hydro to develop market potential estimates. Once developed, these market potential results will be used to support future, long-term planning work such as the creation of DSM options for the next IRP.

10.4.2 BC Hydro Has Extended the Funding Period for Capacity-Focused Initiatives

The DSM Plan continues to include capacity-focused pilots and trial offers that were identified in the Previous Application. These pilots and trial offers are focused on shifting the timing of peak demand in areas where BC Hydro faces capacity constraints. In the Previous Application, BC Hydro proposed a total budget of $38.6 million for these initiatives from fiscal 2017 to fiscal 2019. This DSM Plan extends that budget to fiscal 2021 but reduces the overall total by 12 per cent to $34 million. Table 10-9 below shows the annual breakout of the current expenditure plan, compared to the Fiscal 2017 to Fiscal 2019 Plan.

Table 10-9 Capacity-Focused Expenditures

	Original Expenditures from F2017 to F2019 Revenue Requirements Application ($ million)	Revised Expenditures ($million)
F2017	10.0 (plan)	8.4 (actual)
F2018	14.2 (plan)	6.9 (actual)
F2019	14.4 (plan)	7.4 (plan)
F2020	0.0	6.9 (plan)
F2021	0.0	4.3 (plan)
Total	**38.6**	**33.9**

BC Hydro decided to extend the time period to assess capacity-focused pilots and trial offers due to the complexity of assessing the impacts and value of capacity-focused DSM to BC Hydro's system. This also provides more time to incorporate past learnings into new activities, consider changing technologies and accommodate the long lead times required for some customer projects.

Within this proposed budget, BC Hydro will continue to conduct demand response trials in the residential, commercial and industrial sectors. BC Hydro plans to test different solutions in a number of constrained substation areas. The objective of these tests will be to determine whether the combination of demand response activities and targeted energy efficiency offers can shift the timing of peak demand in a constrained local area.

10.4.3 BC Hydro Builds on EfficiencyBC Program Funding for Low-Carbon Electrification Undertakings

Since the Previous Application, there have been a number of developments on low-carbon electrification.

Beginning in fiscal 2018, BC Hydro moved forward with several initial Low-Carbon Electrification DSM Programs/Projects (collectively referred to as "Initial LCE Projects") to assess and support immediate low carbon electrification opportunities among our customers. These Initial LCE Projects also:

- Helped us gain a greater understanding of the technology, market, and barriers that customers and BC Hydro would face when developing low carbon electrification options; and
- Provided BC Hydro with the ability to act early and capture time-sensitive opportunities that could help inform the development of a broader low carbon electrification plan.

Further details are provided in Appendix Y, including information on where BC Hydro expects to incur expenditures in fiscal 2019 and beyond.

In fiscal 2019, Government launched the EfficiencyBC program to reduce greenhouse gas emissions in the province. This $24 million, government funded program provides financial incentives to help households and businesses save energy and reduce greenhouse gas emissions by switching to high-efficiency heating equipment and making building-envelope improvements. BC Hydro is delivering the fuel switching component of the EfficiencyBC program on Government of B.C.'s behalf, within our service territory. This component helps customers switch from fossil fuels to electricity. The expenditures associated with implementing the EfficiencyBC program are borne by the Government of B.C. and not by ratepayers.

Coinciding with the delivery of the fuel switching component of the EfficiencyBC program and further to the Initial LCE Projects, BC Hydro has developed a new BC Hydro funded low carbon electrification program (referred to as "BC Hydro LCE Program"), which has been coordinated to align, and not overlap with, government funded greenhouse gas emissions reduction programs. Specifically, the program has been developed to reach customers not addressed by EfficiencyBC or by Government funded transportation programs. The BC Hydro LCE Program is described further in Appendix Y.

Should Government bring forward additional programs in the future that would overlap with activities planned or underway with funding from BC Hydro, we can make adjustments to our plans so that any overlap is needed and by design.

BC Hydro expects to develop a future plan for low carbon electrification that is informed by the learning gained through Initial LCE Projects and the BC Hydro LCE Program as well as Government of B.C.'s CleanBC Plan.

10.4.4 Modifications to the Fiscal 2017 to Fiscal 2019 DSM Plan

As described in Appendix X, BC Hydro has made a number of changes to the DSM Plan in response to BCUC direction, to support Government priorities related to residential affordability and to respond to changes to the Demand-Side Measures Regulation. These changes were made by re-allocating expenditures within the overall traditional DSM funding envelope.

These changes include:

- Launching a new Non-Integrated Areas program;
- Taking steps to increase participation for the Low-Income program;
- Increasing Home Renovation Rebate offers, including expanding heat pump measures to benefit customers in regions without access to natural gas;
- Launching a new Social Housing initiative for qualified social housing providers;
- Reducing commercial and industrial program budgets;
- Re-categorizing energy management activities into a new program called Energy Management Activities within each sector, to align with the Demand-Side Measures Regulation;[363] and
- Improving the presentation of codes and standards savings to make it more understandable.

[363] The expenditure shifts resulting from this re-categorizing are reconciled in section 10.5.7.

Please refer to section 2.3 of Appendix X for a discussion of the program changes, and section 10.2.3 for a discussion of codes and standards.

10.5 Fiscal 2020 to Fiscal 2021 Planned Expenditures, Energy and Capacity Impacts, Cost-Effectiveness and Other Benefits

This section describes the forecast expenditures and energy and capacity impacts, as well as the cost-effectiveness and other benefits of BC Hydro's DSM initiatives. This section also sets out BC Hydro's request to revise the previously directed approach to allocating portfolio-level costs to programs, provides evidence on the persistence of DSM savings in support of the current 15-year amortization period for DSM expenditures in rates, and describes how BC Hydro has re-categorized its energy management activities into a new program called Energy Management Activities within each sector.

10.5.1 Forecast Expenditures and Energy and Capacity Impacts

The tables below provide the expenditures as well as the energy and capacity impacts of various programs. Table 10-10 provides a detailed breakdown of planned expenditures. Table 10-11 provides a detailed breakdown of the energy impacts. Table 10-12 provides a detailed breakdown of the capacity impacts.

Table 10-10 Fiscal 2020 to Fiscal 2021 Expenditure Summary ($ million)

	F2020 Plan	F2021 Plan	Total
Rate Structures	0.5	0.5	1.0
Programs			
Residential	18.4	19.7	38.1
Commercial	18.9	17.5	36.4
Industrial	26.5	26.9	53.4
Total Programs (excluding TMP)	63.7	64.1	127.8
Capacity-focused	6.9	4.3	11.1
Supporting Initiatives	19.8	20.2	40.0
Thermo-Mechanical Pulp	0	27.2	27.2
Low-Carbon Electrification	18.3	9.7	28.0
Total Expenditures	109.2	126.0	235.1

Table 10-11 Fiscal 2020 to Fiscal 2021 Energy Impact Summary (GWh/year)

	F2020 Plan	F2021 Plan
New Incremental Energy Savings (GWh/year)		
Codes and Standards	356	411
Rate Structures	117	118
Programs		
Residential	36	36
Commercial	59	52
Industrial	132	136
Thermo-Mechanical Pulp	0	100
Total Programs	227	324
Total New Incremental Energy Savings	700	853
New Incremental Load Growth (GWh/year)		
Low-Carbon Electrification	230	127

Table 10-12 Fiscal 2020 to Fiscal 2021 Associated Capacity Impact Summary (MW)

	F2020 Plan	F2021 Plan
New Incremental Associated Capacity Savings (MW)		
Codes and Standards	79	88
Rate Structures	14	14
Programs		
Residential	10	10
Commercial	9	8
Industrial	16	16
Thermo-Mechanical Pulp	0	12
Total Programs	35	46
Total New Incremental Associated Capacity Savings	128	147
New Incremental Associated Capacity Growth (MW)		
Low-Carbon Electrification	33	16

10.5.2 Other Benefits

In addition to energy and capacity impacts, additional benefits will also be achieved. These benefits include a reduction in BC Hydro's overall revenue requirements, economic development and environmental benefits as well as customer benefits. These benefits are outlined in section 3.3 of Appendix X and summarized below. The values provided are for a ten-year period (fiscal 2020 to fiscal 2029):

- GDP impacts of $1.1 billion;
- Employment of 11,600 person-years;
- Provincial revenue of $115 million; and
- Non-energy customer benefits such as reduced waste generation or product losses, reduced maintenance costs, and extended equipment life.

In addition, BC Hydro's traditional DSM programs are forecast to reduce the province's GHG emissions as customers reduce their natural gas usage along with their electricity usage. The new Non-Integrated Areas Program is also expected to reduce GHG emissions by reducing diesel generation. Overall, at the end of fiscal 2021, savings of 5,000 tonnes of CO^2e/year are forecast from traditional DSM. In addition, the low-carbon electrification undertakings for fiscal 2020 to fiscal 2021 are anticipated to save approximately 350,000 tonnes of CO^2e/year by supporting fuel switching.

10.5.3 BC Hydro's Traditional DSM is Cost-Effective

The Utility Cost and Total Resource Cost tests are standard cost tests used in the DSM industry to assess cost effectiveness. The results of cost-effectiveness tests are typically expressed in a benefit-cost ratio. A ratio of greater than 1.0 means that benefits exceed costs and that the DSM program or portfolio is cost effective under that particular test.

The results of the cost-effectiveness tests can also be expressed as a levelized cost of energy (dollar per MWh of energy saved). In calculating the costs for this metric, any non-energy benefits, such as capacity benefits, are subtracted from the DSM implementation costs to get a net cost, which is then expressed on a per MWh basis. For levelized costs, a lower result is better. A negative net levelized cost indicates that non-energy benefits exceed the DSM costs. A larger negative value is better than a smaller negative value or any positive value. The resulting levelized cost can be compared to a value such as the market price of electricity, or to the levelized cost of energy for new supply-side resources.

The Utility Cost Test indicates the impact of a DSM initiative or portfolio on the utility's revenue requirements. The benefits included in the Utility Cost test reflect the value to the utility of the electricity saved through DSM initiatives. The costs in the Utility Cost Test represent the cost to BC Hydro of implementing DSM initiatives. If the benefits exceed the costs, the impact of DSM will be to lower BC Hydro's revenue requirements. Consistent with the Previous Application, BC Hydro is using the export market price to value the energy savings in this test period. This approach ensures that even surplus energy resulting from DSM would have a positive impact on BC Hydro's revenue requirements. BC Hydro applies this test as a screening filter to prioritize DSM investments and to inform BC Hydro's business decisions.

The price of electricity on the wholesale market is approximately $30 per MWh. A levelized utility cost of DSM that is less than $30 per MWh means that the energy savings from DSM cost less than the price BC Hydro could receive on the market for selling any surplus energy resulting from DSM. DSM with a levelized utility cost less than $30 per MWh reduces BC Hydro's overall revenue requirements and overall customer bills.

The Total Resource Cost Test is presented because the Demand-Side Measures Regulation stipulates that the BCUC is required to use this test for determinations of cost-effectiveness. Costs in the Total Resource Cost Test include both BC Hydro's costs and the cost to participants of implementing DSM initiatives. The benefits reflect the benefits to participating customers and the benefits represented by the avoided cost of electricity supply resulting from DSM savings. Participant non-electricity benefits (e.g., operation and maintenance savings resulting from the installation of a more efficient technology, or natural gas savings that result from a building upgrade) are also included. If the benefits exceed the costs, this indicates that DSM is a lower-cost resource than other supply side resource options, as defined by the Regulation.

The Demand-Side Measures Regulation requires that a long-run marginal cost (**LRMC**) of acquiring electricity from clean or renewable resources in British Columbia be used to assess the cost-effectiveness of demand-side measures.[364] This means that the market price cannot be used for this test. The Total Resource Cost Test can also be used to assess how a DSM initiative or portfolio compares to the cost of other supply side resource options. However, as BC Hydro is in a period

[364] Specifically, section 4 (1.1(b)) of the Demand-Side Measures Regulation states that the avoided electricity cost respecting a demand-side measure is an amount that the Commission is satisfied represents the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia.

of energy surplus, we are not choosing between DSM and other supply side resource options as part of an acquisition process.

For the purposes of assessing the Total Resource Cost Test under the Demand-Side Measures Regulation, recognizing that BC Hydro is not using this test to inform an energy acquisition process, BC Hydro used an avoided cost of $105 per MWh, based on BC Hydro's last LRMC presented in the Previous Application. This value is based on an outdated assessment of greenfield wind projects, including BC Hydro's cost to integrate and deliver energy to the load centre (Lower Mainland). It is an outdated value that is no longer correct and should not be given any weight.

BC Hydro has not updated the LRMC for this application but plans to do so in the next IRP[365]. Internal decisions on demand-side measures are based on the Utility Cost Test at market price and not on the LRMC.

The cost-effectiveness of BC Hydro's DSM initiatives, as demonstrated by their benefit-cost ratios and levelized costs, is provided in Table 10-13 below.

[365] As discussed in Chapter 2, section 2.2.2., the Government of B.C. issued the BC Hydro Integrated Resource Plan Regulation (B.C., Reg. 266/2018) under the *Clean Energy Act* prescribing February 28, 2021 as the date for BC Hydro's next IRP.

Table 10-13 Benefit-Cost Ratios and Net Levelized Costs ($/MWh)

	Benefit-Cost Ratios		Net Levelized Costs ($/MWh)	
	Utility Cost Test (Market Price at $30 per MWh)	Modified Total Resource Cost Test (LRMC at $105 per MWh)	Utility Cost ($)	Total Resource Cost ($)
Codes and Standards	n/a	n/a	n/a	n/a
Rate Structures	11.1	1.4	(4)	73
Programs (including TMP)	1.7	3.6	12	(11)
Total Portfolio (including TMP, excluding Codes and Standards savings[366])	1.1	2.5	27	14

As shown in Table 10-13 above:

- The net levelized utility cost of $27 per MWh is lower than the market price of $30 per MWh. This means that BC Hydro's DSM portfolio is cost-effective under the Utility Cost Test; and
- BC Hydro's DSM initiatives have a Total Resource Cost Test result of $14 per MWh. This means that BC Hydro's DSM portfolio would still be cost-effective under the Demand-Side Measures Regulation, even with a significant decrease in the value of the LRMC of acquiring electricity generated from clean or renewal resources in British Columbia, compared to the value used.

Under the Demand-Side Measures Regulation, the cost-effectiveness of "specified demand-side measures" is determined by whether the portfolio as a whole is cost effective. Table 10-13 demonstrates that the portfolio as a whole is cost-effective. Accordingly, our specified demand-side measures are also determined to be cost-effective. Specified demand-side measures include the Public Awareness

[366] As described in section 10.2.3, codes and standards savings are not included in the calculation of portfolio level cost-effectiveness and levelized costs.

Supporting Initiative, sector Energy Management Activities, technology innovation activities, and codes and standards support.

10.5.4 BC Hydro's Low-Carbon Electrification Undertakings are Cost Effective

BC Hydro has chosen to engage in undertakings that are within one or more class of undertakings defined in sections 4(3)(a), 4(3)(b), 4(3)(c) or 4(3)(d) of the GGRR. Undertakings are in a class of undertakings defined in section 4(3)(a) and 4(3)(b) of the GGRR if they meet the cost-effectiveness test. The cost-effectiveness test requires that each undertaking that is an undertaking within the class of undertakings defined by subsections 4(3)(a) or 4(3)(b) of the GGRR must have a positive net present value (**NPV**), with the measure of a program's NPV being that of all of the programs that fall within the class of undertakings described in subsections 4(3)(a) and 4(3)(b) of the GGRR. Specifically, benefits mean all revenues BC Hydro expects to earn as a result of implementing LCE programs/projects falling under subsections 4(3)(a) or 4(3)(b), less revenues that would have been earned from the sale of that electricity to export markets. Costs mean all the costs BC Hydro expects to incur to implement LCE programs falling under subsections 4(3)(a) or 4(3)(b), including development and administration costs. The GGRR cost-effectiveness test is measured only at the time BC Hydro decides to carry out a program/project. There is no other cost-effectiveness test applicable to prescribed undertakings.

The NPV of all of BC Hydro's programs/projects prescribed under section 4(3)(a) and 4(3)(b) of the GGRR including BC Hydro's proposed low carbon electrification expenditures for fiscal 2020 and fiscal 2021 is $134.7 million, which indicates that these undertakings are cost-effective. Further details are shown in Appendix Y.

10.5.5 Direction 61 Regarding Allocation of Portfolio Costs to Programs Should be Rescinded

In this application, BC Hydro is requesting that Directive 61 from the BCUC's decision on BC Hydro's Fiscal 2005 to Fiscal 2006 Revenue Requirements Application (**Directive 61**) be rescinded. Directive 61 requires portfolio-level costs to be allocated to programs. It states:

> "Portfolio Level Costs should be allocated to programs, and BC Hydro is directed to use the same allocation methodology based on kWh savings as used in Exhibit B1-81."

To assess cost effectiveness in previous applications, BC Hydro allocated a prorated amount of costs from portfolio-level initiatives to the cost of each program based on the energy savings, as required by Directive 61.

In this application, BC Hydro has only attributed costs to programs if they are necessary to operate the program. As further explained below, this approach is more consistent with the Demand-Side Measures Regulation and industry practice, and also facilitates more appropriate marginal cost decision making when designing a DSM portfolio.

10.5.5.1 Directive 61 is Inconsistent with the Demand Side Measures Regulation

As the BCUC indicated in its decision on BC Hydro's Previous Application:

> "The Demand-Side Measures Regulation defines the DSM cost tests to be used by the Commission in evaluating a DSM allocation under section 44.2 (5.1) (d) of the UCA".[367]

Since Directive 61 was issued, the cost effectiveness testing of DSM expenditures has become subject to the Demand Side Measures Regulation. Section 4 of the Demand-Side Measures Regulation prescribes how the industry-standard cost-effectiveness tests are to be applied, including specifying the use of the Total

[367] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 73.

Resource Cost, the avoided capacity cost, and the attribution of non-energy benefits. The attribution of portfolio-level costs to programs is not endorsed by the Demand-Side Measures Regulation or the Guide to the Demand-Side Measures Regulation published by Government.

In addition, the Directive 61 approach is inconsistent with section 4(4) of the Demand-Side Measures Regulation which requires that "specified demand-side measures", which include energy efficiency training, community engagement and energy management programs, be evaluated at a portfolio-level. Directive 61 is inconsistent with this requirement as these types of programs could be considered portfolio-level costs which are required to be allocated to programs.

10.5.5.2 Directive 61 is Inconsistent with Industry Practice

Directive 61 is also inconsistent with industry practice. Industry practice does not suggest that there should be an attribution of portfolio-level costs to individual programs. The recent National Standard Practice Manual states that "fixed portfolio-level costs should not be allocated to programs for the purpose of assessing the cost-effectiveness of individual programs".[368] BC Hydro also notes that FortisBC Energy Inc. is not required to allocate portfolio-level costs to programs.[369]

10.5.5.3 Directive 61 is Not Appropriate for Marginal Decision Making

Allocating portfolio-level costs to programs is not appropriate for marginal decision-making because this allocation overstates a program's incremental costs when assessing cost-effectiveness. This is because the portfolio-level costs are not causally connected to the program, but arbitrarily allocated to programs based on the percentage of savings of the portfolio. The inclusion of portfolio-level costs could

[368] https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf (page 85).

[369] FortisBC Energy Inc.'s 2019-2022 DSM Expenditures Plan application, page 29 outlines the treatment of specified demand-side measures within cost-effectiveness tests, and Appendix A, pages 5 and 53, outline treatment of portfolio level costs and enabling costs. FortisBC's application was approved by BCUC Order No. G-10-19.

shift the result for a program from a net benefit to a net cost, which could lead to a decision not to implement the individual program. This shift could result in a program with a net benefit not being implemented. For this reason, it is more appropriate to only consider portfolio-level costs when looking at the cost effectiveness of the overall portfolio, not the cost effectiveness of individual programs. This allows decisions on individual programs to be based entirely on the merits of the program itself.

In summary, BC Hydro is requesting that the BCUC rescind Directive 61 because it is inconsistent with the Demand-Side Measures Regulation and industry practice and because it is not appropriate for marginal decision-making.

10.5.6 Persistence of Energy Impacts Supports Existing Amortization Period

Section 7 (d) of Direction No. 7 provided direction to the BCUC on the amortization period of the DSM Regulatory Account. As explained in Chapter 2, section 2.2.1, as a result of the Comprehensive Review, Direction No. 7 to the BCUC has been repealed. In addition, as explained in Chapter 2, section 2.6.4, the Direction to the BCUC Respecting Undertaking Costs requires the BCUC to allow BC Hydro to defer the costs incurred for prescribed undertakings to the DSM Regulatory Account. Consistent with this direction, BC Hydro is requesting BCUC approval to defer low carbon electrification expenditures for prescribed undertakings pursuant to section 18 of the *Utilities Commission Act* to the DSM Regulatory Account.

The 15-year amortization period of the DSM Regulatory Account is based on the average measure life of DSM initiatives. The inclusion of the expenditures for low carbon electrification undertakings in the DSM Regulatory Account means that low-carbon electrification expenditures now impact the average measure life of DSM initiatives captured in the account. Accordingly, in this application, BC Hydro has reviewed the average measure life of DSM initiatives.

BC Hydro applies a standardized approach to assess the effective measure life of individual DSM initiatives. This standardization supports uniform application of the effective measure life (also referred to as persistence) of energy impacts from a DSM activity. It also provides consistency in the planning, estimating, reporting, evaluation and calculation of cost effectiveness and supports effective and efficient quality assurance.

To determine effective measure life values, BC Hydro uses credible third-party research including research from the Public Service Commission of Wisconsin, the California Public Utilities Commission, the 2001 Database for Energy Efficiency Resources, and Skumatz Economic Research Associates Inc. Where there is no existing reference to effective measure life, BC Hydro has recommended a value based on our professional judgment and experience.

Table 10-14 provides the weighted average measure life of DSM impacts over the fiscal 2020 to fiscal 2021 test period and over the next 10 years (fiscal 2020 to fiscal 2029).[370]

[370] A ten-year period was selected to improve the stability of the accounting treatment by de-emphasizing individual projects, which can affect the average measure life in individual years.

Table 10-14 Average Measure Life (years)[371]

	2-Year Period F2020-F2021		10-Year Period F2020-F2029	
	GWh Weighted	$ Weighted	GWh Weighted	$ Weighted
Codes and Standards	30.0	30.0	30.0	30.0
Conservation Rates	1.3	1.3	1.2	1.2
DSM Programs	10.4	12.2	11.8	13.2
Low-Carbon Electrification	27.0	24.9	24.4	19.8
Codes and Standards, Conservation Rates, and DSM Programs	**18.7**	**13.5**	**17.9**	**14.7**
DSM Programs and Low-Carbon Electrification	**17.1**	**15.0**	**16.2**	**15.0**

The values in Table 10-14 above are considered to be conservative as the calculation equates the effective measure life of a DSM initiative with the persistence of the savings attributable to the utility program. However, some customers will re-install an efficient measure when the initial measure has reached its end-of-life, rather than revert to an inefficient measure. In these cases, the persistence of the DSM initiative continues beyond the effective measure life. In recognition of this effect, the California Public Utilities Commission uses a deemed assumption that 50 per cent of savings persist beyond the expiration of the measure's life in its Energy Efficiency Policy Manual.[372]

Based on the estimated average measure lives of DSM impacts shown in Table 10-14, BC Hydro believes that the existing amortization period of 15 years for the DSM Regulatory Account remains appropriate. The DSM Regulatory Account is discussed further in Chapter 7, section 7.7.3.

[371] The average measure life is based on the median number of years that the measure installed is still in place and operable. Factors considered include field conditions, obsolescence, building remodeling, renovation, demolition and occupancy changes. Measure life assumptions are documented in the Demand-Side Management Standard, "Effective Measure Life and Persistence".

[372] http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/EEPolicyManualV5forPDF.pdf, page 34.

10.5.7 Re-categorizing of Energy Management Activities Aligns with Demand-Side Measures Regulation

The *Demand-Side Measures Regulation* was amended in 2017 to include an "Energy Management Program" (meaning a program to assist customers to optimize energy use) as a "Specified Demand-Side Measure". To align with this change, BC Hydro re-categorized its energy management activities into a new program called Energy Management Activities within each sector.

Energy Management Activities are different from most other programs because they do not offer incentives to customers to adopt a particular measure. Rather, in direct and indirect ways, they assist customers in managing and optimizing their energy use. BC Hydro strives to provide assistance to customers in a holistic manner by bringing energy specialists directly into customer operations, increasing customers' knowledge of their options, encouraging behavior change, and providing knowledgeable trades in the industry that can help customers make the right choices.

Table 10-15 below shows the expenditure effect of the re-categorization. As shown, there is no net change to sector or portfolio budgets as a result of this exercise.

Table 10-15 Energy Management Activity Expenditures

	F2020 Expenditures Before Energy Management Re-categorizing ($ million)	F2020 Expenditures After Energy Management Re-categorizing ($ million)	F2020 Expenditure Differences ($ million)	F2021 Expenditures Before Energy Management Re-categorizing ($ million)	F2021 Expenditures After Energy Management Re-categorizing ($ million)	F2021 Expenditure Differences ($ million)
DSM Programs						
Residential Sector						
Low Income	5.8	5.8	0.0	6.9	6.9	0.0
Non Integrated Areas	1.2	1.2	0.0	1.4	1.4	0.0
Behaviour	3.7	0.0	-3.7	3.6	0.0	-3.6
Retail	2.3	2.1	-0.2	2.3	2.1	-0.2
Home Renovation Rebate	4.4	4.2	-0.2	4.6	4.4	-0.2
Sector Enabling Activities	0.9	0.0	-0.9	0.9	0.0	-0.9
Energy Management Activities	0.0	5.0	5.0	0.0	4.9	4.9
Residential Sector Total	18.4	18.4	0.0	19.7	19.7	0.0
Commercial Sector						
LEM - Commercial	14.5	9.0	-5.4	14.4	9.1	-5.3
New Construction	3.7	3.7	0.0	2.4	2.4	0.0
Sector Enabling Activities	0.8	0.0	-0.8	0.8	0.0	-0.8
Energy Management Activities	0.0	6.2	6.2	0.0	6.1	6.1
Commercial Sector Total	18.9	18.9	0.0	17.5	17.5	0.0
Industrial Sector	-					
LEM - Industrial	25.8	18.3	-7.5	26.2	18.5	-7.7
Thermo-Mechanical Pulp	0.0	0.0	0.0	27.2	27.2	0.0

	F2020 Expenditures Before Energy Management Re-categorizing ($ million)	F2020 Expenditures After Energy Management Re-categorizing ($ million)	F2020 Expenditure Differences ($ million)	F2021 Expenditures Before Energy Management Re-categorizing ($ million)	F2021 Expenditures After Energy Management Re-categorizing ($ million)	F2021 Expenditure Differences ($ million)
Sector Enabling Activities	0.7	0.0	-0.7	0.7	0.0	-0.7
Energy Management Activities	0.0	8.2	8.2	0.0	8.4	8.4
Industrial Sector Total	**26.5**	**26.5**	**0.0**	**54.1**	**54.1**	**0.0**

10.6 BC Hydro Appropriately Manages its Traditional DSM Initiatives and Low-Carbon Electrification Undertakings

This section provides an overview of BC Hydro's management activities to monitor and assess performance results, and keep the initiatives on track. Further details of these management activities are provided in Appendix X.

10.6.1 Delivery Risks are Identified and Mitigated

BC Hydro's approach to the management of traditional DSM and low-carbon electrification undertakings is informed by the identification and assessment of delivery risks and the development of mitigation measures at various stages of DSM implementation. Risks are assessed and mitigated at the initiative level as well as at the portfolio level.

A detailed discussion of delivery risks and mitigation is provided in section 4.2 of Appendix X.

10.6.2 Performance is Comprehensively Managed

BC Hydro manages the performance of DSM initiatives in a comprehensive manner. This includes tracking a number of performance metrics as well as regular management oversight and reporting, as described below.

- Electricity and capacity savings are confirmed through a series of activities including technical review, site inspection, measurement and verification, and evaluation. These activities are intended to improve the accuracy of the savings estimates and reduce exposure to risks. Section 4.3 of Appendix X describes these activities. A more detailed overview of the measurement and verification, and evaluation activities as well as the annual evaluation summary reports to the BCUC is provided in Appendix AA.

- For low-carbon electrification undertakings, load growth and GHG impacts are confirmed through a similar series of activities as shown in section 4.3. of Appendix X.
- Savings and load growth impacts are reported to the BCUC through two annual reports. Savings are reported in the Annual DSM Reports to the BCUC (Appendix Z) while load growth is reported in the Greenhouse Gas Reduction Regulation Annual Reports (Appendix BB).
- BC Hydro's DSM governance process includes regular reporting to the Executive Team and the Board of Directors. This is described further in section 4.1.3 of Appendix X.

10.6.3 Recent Audit Found that Processes and Controls Are in Place

In fiscal 2017, BC Hydro's Audit Services department engaged experts from GDS Canada Consulting Ltd. to help assess whether effective processes and controls were in place for our DSM activities and programs. GDS Canada Consulting Ltd. has over 40 years of experience in market evaluations and managing energy efficiency programs. The internal audit found that processes and controls are in place for planning, program development, implementation and evaluation.

BC Hydro
Power smart

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Chapter 11

Performance Based Regulation

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11.1 Executive Summary

British Columbia Hydro and Power Authority (**BC Hydro**) files this report on Performance Based Regulation (**PBR**) in response to Directive 28 from the British Columbia Utilities Commission (**BCUC**) in its Decision on BC Hydro's Previous Application. [373]

11.1.1 Scope of this Report

In its Decision on our Previous Application, the BCUC acknowledged previous cost cutting measures by BC Hydro and the potential for further savings through the Government of B.C.'s Comprehensive Review. However, it expressed concern regarding BC Hydro's base operating costs and suggested that a rate setting mechanism, like PBR, could help BC Hydro accomplish its cost control objectives and provide incentives to improve productivity while maintaining service quality. [374]

The BCUC recommended that BC Hydro consider a PBR plan and directed a PBR report to be filed, addressing the following issues:

- A discussion of the types of PBR plans that may be suitable for BC Hydro (i.e., Revenue Cap, Price Cap, hybrid);
- The length of PBR term that may be appropriate;
- A discussion of potential earnings sharing mechanisms that may be suitable for BC Hydro;
- The appropriateness of off-ramps;
- How capital spending could be managed as part of the PBR program;
- A list of potential key performance indicators to assist BC Hydro and the BCUC to evaluate progress during the PBR term;

[373] BCUC Decision and Order No. G-47-18, BC Hydro Ficsal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), pages 111 and 117.
[374] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), pages iv and 110.

- An Annual Review process and/or other monitoring processes during the PBR term; and
- An implementation timetable, including a proposed schedule of consultation with representatives of key customer groups and BCUC staff.[375]

11.1.2 Our Approach to this Report

FortisBC, an investor-owned natural gas and electric utilities in British Columbia, are currently operating under PBR. In its Decision on FortisBC's 2014 to 2018 PBR Application, the BCUC stated:

> "The Commission Panel is not looking at this Application from a short–term viewpoint. We see an opportunity to make significant change over the long term with the way regulation is conducted in this jurisdiction and the way in which revenue requirements are determined."[376]

BC Hydro agrees that the shift from cost of service regulation to PBR would be significant. It would represent a significant change for all stakeholders, including BC Hydro, interveners and the BCUC. We believe that the adoption of PBR for BC Hydro should be carefully considered.

Accordingly, to assist us in identifying the opportunities and challenges associated with the adoption of PBR for BC Hydro, we retained Dr. Dennis Weisman, Ph.D., a recognized expert in PBR.

At BC Hydro's request, Dr. Weisman completed a whitepaper titled *"A Report on the Theory and Practice of Performance-Based Regulation",* which outlines the theory and application of a successful approach to PBR. The whitepaper is included as Appendix FF and referenced throughout this report. Dr. Weisman also previously co-wrote a paper with Dr. David Sappington titled *"Assessing the Treatment of*

[375] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 111 (paraphrased and re-ordered).

[376] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 14.

Capital Expenditures in Performance-Based Regulation Plans", which was commissioned by the Edmonton Power Corporation (**EPCOR**) and filed with the Alberta Utilities Commission in 2016. This paper is included as Appendix GG.

BC Hydro's report is divided into three parts.

- First, in section 11.2, we provide an overview of cost of service regulation and PBR as well as a discussion of the different roles of the regulator, interveners and the utility under both approaches.
- Second, in sections 11.3 through 11.7, we provide our initial conclusions in response to the issues raised by the BCUC. These initial conclusions provide a framework for a PBR plan, should the BCUC decide to adopt PBR for BC Hydro.
- Third, in section 11.8, we review the potential implications of adopting PBR and conclude that BC Hydro should continue to be regulated through cost of service regulation at this time.

11.1.3 PBR is a Different Approach to Regulation

BC Hydro is currently regulated through a cost of service approach. Under this approach, BC Hydro submits evidence to the BCUC regarding the costs we expect to incur to provide safe, reliable, affordable and clean electricity to our customers. The BCUC reviews these costs and sets rates to allow BC Hydro to recover only those costs that it determines to be prudently incurred plus a reasonable rate of return (net income).

In simple terms, PBR involves setting rates through a formula. This formula de-links costs and rates for a specified period of time. A typical approach to PBR in the electricity industry is a hybrid plan where some costs are subject to a PBR formula and other costs are set through cost of service regulation.

Under PBR, a cost of service review would be conducted first, to set BC Hydro's base costs. In subsequent years, cost components subject to PBR would be determined by applying a formula to adjust the previous year's costs for the effects of inflation and productivity improvements. This means that the amount of revenue recovered through rates in subsequent years would be independent from BC Hydro's costs, rather than dependent on them.

Once the base costs are established, the BCUC would not focus on reviewing the cost components subject to PBR. Instead, the BCUC would design and implement mechanisms to incent the discovery of new savings. This shift in focus would provide BC Hydro with increased autonomy from detailed regulatory reviews. If BC Hydro were able to discover efficiencies over and above what is required to meet the formula, BC Hydro or the Government of B.C. (our shareholder) would retain those savings or share them with our customers, until rates were "re-based" to reflect the cost of service at the end of the PBR term.

By allowing BC Hydro to retain all or a portion of the savings over and above what is required to meet the formula, PBR would aim to incent a process through which new savings - that were not previously identified under cost of service regulation - are discovered.

A key difference between these two approaches is the role of BC Hydro, the BCUC and interveners. Under cost of service regulation, BC Hydro must provide a forecast of the costs that it expects to incur and then justify the reasonableness of those costs. The BCUC's role is to acquire information to determine which expenditures are prudent and which expenditures are imprudent. Interveners support this process by submitting information requests and arguments from a customer's perspective.

In contrast, PBR is predicated on providing greater autonomy to the utility. Under PBR, the BCUC's role would be to provide a framework to incent efficient behaviour and then allow BC Hydro to manage its expenditures within that framework without performing a detailed regulatory review that would second guess the decisions made. In exchange for this increased autonomy, BC Hydro would assume both the risk that the PBR formula would not sufficiently fund certain costs as well as the opportunity to retain additional savings, if new efficiencies were discovered, over and above what was required to meet the formula.

11.1.4 Summary of BC Hydro's Responses

We have reviewed the potential implications of adopting PBR and concluded that, at this time, BC Hydro should continue to be regulated through cost of service regulation, for the following four reasons:

- First, cost of service regulation should be given the opportunity to work. BC Hydro believes that unconstrained cost of service proceedings would address the issues raised by the BCUC in its Decision on our Previous Application.
- Second, given that BC Hydro is only now returning to enhanced regulation, it is likely to be more challenging to secure stakeholder support for the principles of PBR. BC Hydro believes that the most effective way to build the familiarity and comfort required to secure stakeholder support for the principles of PBR is through successive cost of service proceedings.
- Third, cost of service regulation is more intuitive and accessible, while PBR is more esotetic and relies heavily on specialized expertise.
- Fourth, BC Hydro does not have a mandate to maximize profits, which can dull the additional "carrot" incentive that PBR attempts to provide. This does not mean that BC Hydro will not seek out and find additional efficiencies in future years. Rather, it means that the incentive to find these efficiencies would come, as it does today, from the obligation and commitment on the part of management to deliver on its mandate within the budget set by the BCUC, and not from the opportunity to increase earnings.

BC Hydro respectfully recommends that the BCUC use this Revenue Requirements Application proceeding to engage interveners to canvass their views.

Should the BCUC decide to adopt PBR for BC Hydro, this report provides the following initial conclusions in response to the issues the BCUC has asked BC Hydro to address. These initial conclusions provide a framework for a PBR plan.

- **Types of PBR Plans:** The most suitable PBR plan for BC Hydro would be a hybrid plan, in which certain costs are subject to a PBR formula and other costs are “carved out” from the formula and reviewed through cost of service regulation. This hybrid plan should be more broad-based than targeted and should “carve out” items over which BC Hydro has little or no control. It will be important to appropriately align the roles and responsibilities of BC Hydro and the BCUC to maintain the distinction between cost of service regulation and PBR under this hybrid approach. The PBR formula should be a revenue cap which caps BC Hydro’s total allowed revenue.
- **Creating and Sharing Benefits Under PBR:** The goal of adopting PBR is to incent a process through which savings – that were not previously identified under cost of service regulation – are discovered. The strength of the incentives provided depends on the extent to which the amount of revenue recovered through rates is independent from BC Hydro’s costs, rather than dependent on them. The PBR term should be at least five years as a longer term would provide stronger incentives. There are trade-offs if stretch factors or Earnings Sharing Mechanisms are used to manage the allocation of benefits during the PBR term. A stretch factor would maintain the distinction between PBR and cost of service regulation and would not counteract the stronger financial incentives for efficient performance that PBR attempts to provide. An Earnings Sharing Mechanism reduces the strength of incentives; however, if an Earnings Sharing Mechanism is desired, then one with a “deadband” would provide stronger incentives than one that shares a set percentage of all earnings above

BC Hydro's allowed net income. Both financial and performance re-openers or off-ramps should be used. The financial triggers should be high enough to incent the vigorous pursuit of efficiencies while remaining low enough to provide a safeguard against excessive profits or losses.

- **Managing Capital and Other Costs under PBR:** A variety of approaches may be used to manage capital spending and other costs incurred by BC Hydro under a PBR plan. Each approach has trade-offs between the incentives provided, the degree of regulatory oversight and the level of certainty that funding will be sufficient to support the required investment. In this chapter, we identify areas where "adders" to the PBR formula or "carve outs" from the formula may be required; however, the appropriate approach should be determined in the context of an overall PBR plan proposal and not in isolation.
- **Monitoring the PBR Plan:** A number of the performance metrics already included in BC Hydro's Service Plan are likely appropriate as key performance indicators to monitor progress under PBR. Some additional customer service and emergency response metrics may need to be added. An Annual Review process, similar to the one adopted by the BCUC for FortisBC, would likely be appropriate for BC Hydro.
- **Implementing the PBR Plan:** BC Hydro has filed a cost of service Revenue Requirements Application for fiscal 2020 and fiscal 2021. BC Hydro suggests that the BCUC provide its decision on the adoption of PBR for BC Hydro in its decision on this Revenue Requirements Application. We believe that BC Hydro should continue to be regulated through cost of service regulation at this time. However, if the BCUC decides to adopt PBR for BC Hydro, following this Revenue Requirements Application proceeding, BC Hydro could file a proposed PBR plan, using fiscal 2021 as the base year, by February 2021. The consultation process on a PBR plan for BC Hydro could be similar to the model used for BC Hydro's 2015 Rate Design Application. A negotiated settlement

process to identify areas of common agreement, prior to BC Hydro's submission of a proposed PBR plan, may help to secure intervener and stakeholder support for elements of the proposed plan and streamline the subsequent regulatory review process.

11.2 PBR is a Different Approach to Regulation

In the following sections, BC Hydro provides an overview of cost of service regulation and PBR as well as a discussion of the different roles of the regulator, interveners and the utility under both approaches.

11.2.1 Overview of Cost of Service Regulation and PBR

BC Hydro's rates are currently set through cost of service regulation. Under cost of service regulation, BC Hydro applies to the BCUC to set rates for a certain period and submits evidence regarding the costs we expect to incur to provide safe, reliable, affordable and clean electricity to our customers. This is referred to as our "revenue requirements". The BCUC reviews these costs and sets rates to recover only those costs that it determines to be prudently incurred plus a reasonable rate of return (net income).

BC Hydro has made considerable progress in identifying cost savings under cost of service regulation. We have achieved cost reductions through the 2011 Government of B.C. review and the 2013 10 Year Rates Plan. In addition, the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (**Previous Application**) provided an opportunity for oversight by the BCUC and interveners.

In its Decision on BC Hydro's Previous Application, the BCUC approved our revenue requirements but expressed concerns regarding base operating costs stating:

> "The Panel recognizes that in some cases, comparing forecast cost increases to the rate of inflation may be considered an appropriate measure for evaluating the reasonableness of forecast cost increases in the test period. This method is likely more suitable in situations where a regulator has consistently

> been empowered to oversee all aspects of the utility's forecast and historical expenditures through proceedings in which the underlying base costs were initially established. However, given the Commission's limited involvement in the approval of BC Hydro's recent revenue requirements, the Panel does not have a high degree of comfort in BC Hydro's starting point, being the 2016 base operating costs." [377]

The BCUC went on to suggest that a rate setting mechanism that could help BC Hydro to accomplish its cost control objectives would be of value, stating:

> "Performance Based Rate (PBR) setting mechanisms are implemented successfully in many jurisdictions, particularly in Canada, including BC. PBR provides incentives for utilities to improve productivity and create efficiencies to allow for rates to be more effectively managed, while maintaining service quality."[378]

While cost of service regulation sets rates to recover only those costs that the regulator determines to be prudent, PBR de-links rates and costs for a specified period of time.[379] The premise underlying this break is that since the utility has the strongest understanding of its costs and operations, the regulator should not focus on trying to collect and review this information. Instead, PBR shifts the regulator's focus to the design and implementation of rules that will incent the utility to discover all possible efficiencies and productivity improvements. [380] This shift in focus provides the utility with increased autonomy from detailed regulatory reviews. [381]

While the starting point for PBR is typically a cost of service review to establish a base year, rates in subsequent years are then determined by applying a formula which adjusts the previous year's rates for the effects of inflation and productivity

[377] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 33.
[378] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 110.
[379] Appendix FF, page 8.
[380] Appendix FF, pages 4 to 6.
[381] Appendix FF, page 5.

improvements, through an inflation factor and a productivity factor. [382] This means that the amount of revenue recovered through rates in subsequent years is largely de-linked from the utility's costs over the term of the PBR plan.[383] If a utility is able to discover efficiencies over and above what is required to meet the formula adjustments, it retains all or a portion of those savings until rates are re-based at the end of the PBR term. At that point, some or all of the efficiencies are reflected in customer rates in future years.[384]

By allowing a utility to retain all or a portion of the savings over and above what is required to meet the formula, PBR aims to incent a process through which new savings - that were not previously identified under cost of service regulation - are discovered. [385] The effect of this process is to go beyond the "static" efficiencies that are discovered through aligning costs and prices under cost of service regulation and emulate what would happen in a competitive market where, in an effort to increase their market share, rival producers would continually discover new ways to reduce their costs, achieving "dynamic" efficiencies.[386]

11.2.2 PBR's Use of Incentives and Greater Utility Autonomy Alters the Roles and Responsibilities of All Stakeholders

A key difference between cost of service regulation and PBR is the role of the utility, the regulator and interveners.

Under cost of service regulation, the utility must provide a forecast of the costs that it expects to incur and then justify the reasonableness of those costs. The regulator's role is to determine which expenditures are prudent and which expenditures are imprudent. Interveners support this process by submitting information requests and arguments from a customer's perspective. PBR is premised on the idea that this

[382] Schmidt, page 2.
[383] Appendix FF, pages 8 to 10 and 49 to 50.
[384] Appendix FF, page 8.
[385] Appendix FF, page 5.
[386] Appendix FF, page 22.

approach may have limitations. This concept is explained by Professor Alfred Kahn in *The Economics of Regulation: Principles and Institutions*:

> "Effective regulation of operating expenses and capital outlays would require a detailed, day-by-day, transaction-by-transaction, and decision-by-decision review of every aspect of the company's operation. Commissions could only do so only if they were prepared completely to duplicate the role of management itself." [387]

Under PBR, the regulator's role is to provide a framework and allow the utility the necessary autonomy to manage its expenditures within that framework. As explained by Dr. Michael Schmidt in *Performance-Based Ratemaking: Theory and Practice*:

> "A desirable aspect of price cap regulation lies in the fact that the regulatory authority no longer has to second-guess the utilities' operations and evaluate the prudence of its investment decisions and operating practices. Second-guessing is a difficult task because it is generally recognized that the utility has superior information regarding its business operations including opportunities for reducing costs. Therefore, the regulator must resist-second guessing the utility and rely on the PBR."[388]

These different roles create different responsibilities for both the regulator and the utility. For example, under cost of service regulation, the utility must outline its forecast costs in detail, because it must prove to the regulator that the costs are reasonable. At the same time, the regulator has a responsibility to acquire information to evaluate the prudency of expenditures. However, under PBR, the utility does not have to demonstrate the reasonableness of forecast costs each year and the regulator has a responsibility to resist acquiring and evaluating information so that it does not second guess the decisions of the utility. In exchange for this increased autonomy from detailed regulatory review, the utility assumes greater risk

387 Alfred E. Kahn, The Economics of Regulation: Principles and Institutions, Volume I, New York: John Wiley and Sons, 1970, pages 29 to 30.

388 Dr. Michael R. Schmidt, Performance-Based Ratemaking: Theory and Practice, Public Utilities Reports, Inc., 2000, page 101.

and is provided with the opportunity to retain additional savings.[389] Figure 11-1 provides a matrix of respective responsibilities under both cost of service regulation and PBR:

Figure 11-1 Regulator and Utility Responsibilities under Cost of Service Regulation and PBR

	Regulator	Utility
Cost of Service Regulation	Acquire information to evaluate prudency of expenditures	Provide information so that prudency can be evaluated
Performance Based Regulation	Create a framework and resist second guessing the utility's decisions	Assume greater risk in exchange for greater autonomy from detailed regulatory review

As Dr. Weisman explains, aligning these roles and responsibilities is critical to maintaining the distinction between cost of service regulation and PBR:

> "It follows that if the firm is uncertain as to whether regulatory commitments will be honored, there may be little practical difference between PBR and [cost of service regulation]. In this manner a weak regulatory commitment undermines the superior incentive properties of PBR." [390]

11.3 Suitable Types of PBR Plans if PBR is Adopted

In response to the BCUC's request, this section discusses the types of PBR plans that may be suitable, if the BCUC decides to adopt PBR for BC Hydro.

There are various approaches to designing a PBR plan. A PBR plan may subject all costs to the PBR formula and may include "adders" if there are forecast costs that are not sufficiently funded by the formula. Alternatively, a PBR plan may be a "hybrid" where some costs are subject to the PBR formula and some costs are "carved out" and set through cost of service regulation. In addition, the PBR formula can set a price cap which caps the allowed rate increase or a revenue cap which

[389] Appendix FF, page 11.
[390] Appendix FF, page 50.

caps the allowed total revenue. We believe that the most suitable PBR plan for BC Hydro would be a hybrid plan and that the PBR formula should be a revenue cap.

Under PBR, an inflation factor (or "I" factor) escalates the utility's rates or revenue by an inflation index.[391] As the BCUC has noted, there are many considerations when establishing the appropriate inflation index including which indexes are most suitable, the appropriate allocation between labour and non-labour costs, the weighting of operating and capital costs, and whether to use forecast values, forecast values with a "true-up" or actual values from the previous year.[392]

A productivity factor (or "X" factor) offsets the inflation factor and is meant to represent the average productivity gains of a representative industry peer group, so that they can be passed on to customers through lower rates. It is important to recognize that the "productivity" measure used in the PBR formula means the amount of "output" (energy) per unit of "input" (cost). This means that productivity increases either when the amount of output increases and the amount of input remains the same, or when the amount of output remains the same and the amount of input decreases. Therefore, investments that increase the amount of energy produced tend to increase productivity while investments required for the reliability or sustainment of the electricity system or to support customer service, tend to decrease productivity because they increase costs but do not increase the amount of energy produced.

Dr. Weisman emphasizes that the productivity factor applied to electric utilities under PBR must account for these dynamics, stating:

> "…when productivity growth is declining over time, a backward-looking X factor (one based on historical data) is likely to overestimate the industry's capabilities going forward. This

[391] Appendix FF, page 31.
[392] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), pages 31 to 34.

> may well explain why PBR plans were not renewed or prematurely terminated in the electric power industry… backward-looking X factors in the electricity sector may well result in decreasing price-cost margins over time that would render it more difficult to fund capital requirements…"[393]

The productivity factor is meant to pass average industry productivity gains on to consumers and to be independent of the utility's own performance. This means that while the utility's past performance may inform the productivity factor at the start of a PBR plan, it cannot be used repeatedly. Rather, ongoing adjustments to the productivity factor should be based on a representative peer group of utilities in the same industry. The selection of peer group is fundamental to the fairness of the PBR plan, since benchmarking against utilities that are not facing the same operating circumstances could result in a formula that is too aggressive or too lenient. [394]

Lastly, a PBR formula typically includes an unforeseen factor (or "Z" factor) which allows rates to be adjusted to reflect one-time external events that are beyond the control of the utility. [395] The BCUC has previously determined that Z factors should be included as part of the PBR formula and that the following criteria should determine whether an event qualifies to be reflected in rates through the Z factor:

> 1. "The costs/savings must be attributable entirely to events outside the control of a prudently operated utility;
>
> 2. The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived;
>
> 3. The impact of the event was unforeseen;
>
> 4. The costs must be prudently incurred; and

[393] Appendix FF, pages 16 to 17.
[394] Appendix FF, pages 53 to 54.
[395] Appendix FF, page 32.

5. The costs/savings related to each exogenous event must exceed the Commission-defined materiality threshold." [396]

The BCUC has determined that materiality thresholds are a necessary component of "Z" factor criteria[397] and that these thresholds should be non-aggregated,[398] which means that multiple individual events below the threshold cannot be added together to meet the threshold and receive "Z" factor treatment. However, Dr. Weisman cautions that a non-aggregated materiality threshold may lead to "death by a thousand cuts."[399]

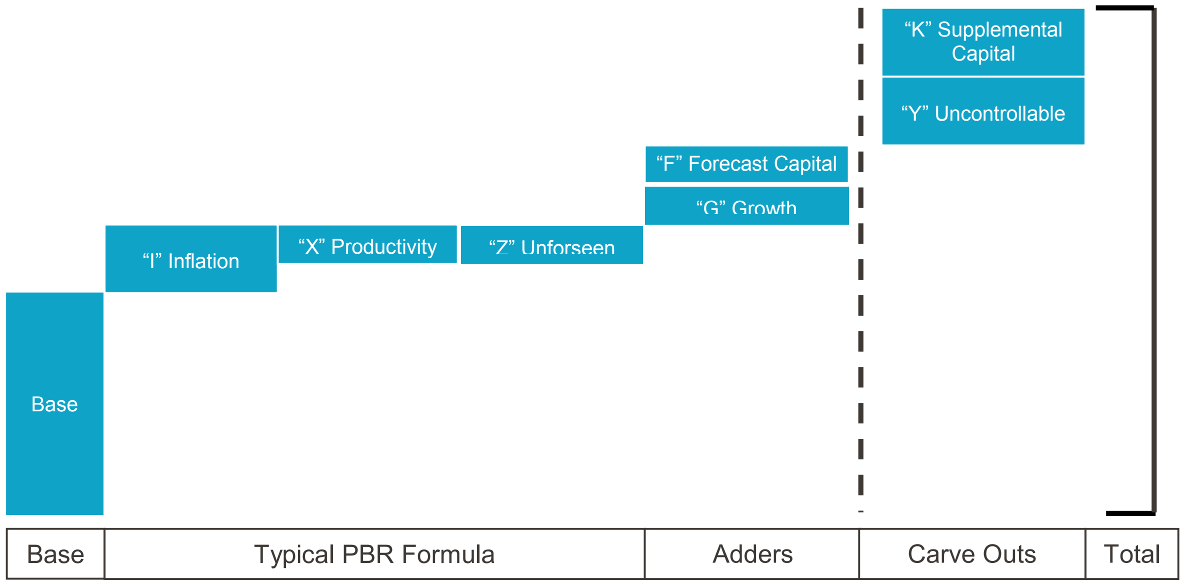
11.3.1 The PBR Plan Should be a Hybrid Approach

As discussed in section 11.2.1, the PBR formula adjusts rates for inflation and productivity improvements.

However, this adjustment may not be able to provide sufficient funding for all of a utility's forecast costs. For example, large capital projects may require "lumpy" investments and energy costs can fluctuate significantly. In these cases, "adders" or "carve outs" may be used. As Dr. Weisman observes, this is common in the electricity industry as the standard PBR formula does not account for recurring expenditures over which the utility has no control and may not generate sufficient revenues to adequately fund required capital investments. [400] Figure 11-2 provides a visual demonstration of how some common "adders" or "carve outs" may be used in combination with the adjustment for inflation and productivity improvements:

[396] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 94.
[397] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 95.
[398] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 96.
[399] Rebuttal Testimony of Dennis L. Weisman, Ph.D., Alberta Utilities Commission, Application No. 1606029, Proceeding ID No. 566, Rate Regulation Initiative (April 4, 2012), page 21.
[400] Appendix FF, page 33.

Figure 11-2 Common "Adders" and "Carve Outs" Under PBR



"Adders" refers to factors that are part of the PBR formula and are intended to increase the amount of funding that the formula provides. "Carve outs" refers to factors that remove costs from the formula entirely. Costs that are "carved out" of the PBR formula are subject to regulatory oversight on a cost of service basis, since those costs flow directly through to rates.[401] Accordingly, "carving out" certain costs results in a "hybrid" approach where some of the utility's costs are subject to the PBR formula and other costs are determined through cost of service regulation.

A PBR formula with "adders" may include the following factors:

- A growth factor (or "G" factor) adds to the escalation provided by the inflation factor so that rates reflect the additional costs required to serve new customers.[402] The BCUC has previously stated that it is "reasonable to conclude that there are cost increases associated with growth" but has noted some complexities including that costs may only increase when a certain

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[401] *Id.*
[402] Appendix FF, page 27.

threshold of growth is reached and that those costs may not increase or decrease in a linear manner. [403]

- A forward-looking factor (also referred to as a “K-bar” or “F” factor) captures forecast costs associated with capital projects that are partially, but not fully, funded through the PBR formula. [404]

A hybrid approach with “carve outs” from the PBR formula may include the following factors:

- An uncontrollable factor (or “Y” factor) reflects recurring expenses that are beyond the control of the utility and should be fully reflected through an adjustment to rates. [405] Examples of items that may be included under a “Y” factor are interest, taxes and post-employment benefit costs. [406] In its 2016 PBR Decision, the Alberta Utilities Commission established the following criteria for “Y” factor treatment:

> “(i) The costs must be attributable to events outside management’s control.
>
> (ii) The costs must be material. They must have a significant influence on the operation of the [utility]; otherwise the costs should be expensed or recognized as income, in the normal course of business.
>
> (iii) The costs should not have a significant influence on the inflation factor in the PBR formulas.
>
> (iv) The costs must be prudently incurred.

[403] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), pages 116 to 117.
[404] Appendix GG, pages 32 to 33.
[405] Appendix FF, page 33.
[406] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), pages 97 to 98.

(v) All costs must be of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts."[407]

In British Columbia, the BCUC has previously observed that the research undertaken to determine expected productivity improvements that should be reflected through the "X" factor must be aligned with the scope of the "Y" factor.[408] In other words, the scope of items covered by the "X" factor must not overlap with the scope of items captured by the "Y" factor, otherwise those costs may be "double counted" in the resulting adjustment to rates.

- A supplemental capital factor (also referred to as "capital tracker" or "K" factor) reflects capital investment required to adequately sustain infrastructure or meet new demand that cannot be accommodated within the adjustment made to rates for inflation and productivity improvements. In other words, capital that is "supplemental" to what can be accommodated under the constraints of the PBR formula. [409]

As Dr. Weisman observes, regulators have struggled to strike the appropriate balance between the capital that is included under the PBR formula and the capital that is supplemental and funded through an adjustment to rates by the "K" factor. [410] Section 11.5.1 provides a summary of the trade-offs between various approaches to managing capital spending under a PBR plan. These approaches may include the use of "adders" such as "G" or "F" factors or the use of "carve outs" such as a "K" factor. In some cases, these factors may be used together. For example, a "F" factor may be used to capture forecast costs associated with capital projects that are partially, but not fully, funded through the PBR formula and the "K" factor may be used to capture costs associated with unique lifecycle capital replacement projects

[407] Alberta Utilities Commission, Errata to Decision 20414-D01-2016, 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities (February 6, 2017), page 89.
[408] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 103.
[409] Appendix FF, page 33.
[410] Appendix FF, pages 46 to 47.

or projects required by external parties, which are outside the normal course of business and therefore not captured at all within the PBR formula.[411]

Overall, we believe that a hybrid approach, which includes some "carve outs" from the PBR formula, would be appropriate for BC Hydro given our capital investment requirements and various uncontrollable costs, which are discussed further in section 11.5.

Dr. Weisman emphasizes that PBR is not "one-size-fits-all",[412] citing a survey by Professor Graeme Guthrie, which concluded that:

> "The two most important lessons to be drawn from the literature surveyed here are that there is no single combination of regulatory settings that is best in all situations and that the various components of a regulatory scheme are interrelated. The most appropriate regulatory scheme for a given situation will depend on the characteristics of the firm and industry being regulated, as well as the institutional environment."[413]

Accordingly, Dr. Weisman provides some principles to guide the design of a PBR approach that appropriately reflects the unique circumstances of a utility:

- It should be more broad-based than targeted so that a utility does not devote excessive attention to those items covered by the PBR formula at the expense of items that are "carved out" of the formula[414] and so that the utility is not incented to make inefficient decisions to push additional costs outside of the PBR formula;[415]
- Items over which the utility has little or no control should be "carved out" of the PBR formula;[416]

[411] Appendix GG, pages 32 to 33.
[412] Appendix FF, page 12.
[413] Graeme Guthrie, "Regulating Infrastructure: The Impact on Risk and Investment," *Journal of Economic Literature,* Volume 44(4), December 2006, page 966.
[414] Appendix FF, pages 13 to 14.
[415] Appendix FF, page 26.
[416] Appendix FF, page 14.

- With regards to capital projects, the productivity improvements assumed by the "X" factor must recognize that increased investment is required in the electricity industry. This investment is necessary to refurbish aging infrastructure and to improve seismic safety so that existing assets may keep producing the same results. These types of investments result in negative productivity improvements, as the amount of resources inputted increases but the output remains the same. Setting a "X" factor that recognizes this trend is important so that as much capital as feasible may be included within the PBR formula. Otherwise, excessive amounts of supplemental capital may need to flow directly through to rates, through the "K" factor, which may weaken the incentives to discover new efficiencies in the planning and delivery of capital projects.[417]

11.3.2 The PBR Formula Should be a Revenue Cap

As explained by the BCUC in its Decision on FortisBC's 2014 to 2018 PBR Application, the PBR formula generally takes the form of a price cap or a revenue cap. Under a price cap, a utility's rates are determined by the previous year's rates as adjusted by the PBR formula. Under a revenue cap, the utility's total allowed revenue is determined by the previous year's total allowed revenue as adjusted by the PBR formula. The primary difference between these two approaches is that under a price cap, the utility's allowed revenue fluctuates as demand fluctuates (e.g., if load is less than forecast then allowed revenue will also be less) while under a revenue cap, allowed revenue is decoupled from demand and remains constant regardless of whether load is more or less than forecast. In other words, under a price cap, the utility assumes the risk associated with changes in demand while under a revenue cap, customers assume the risk associated with changes in demand.[418]

[417] Appendix FF, page 47.
[418] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 19.

As explained in the BCUC's decision on BC Hydro's Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, prior to fiscal 2009, BC Hydro assumed the risk associated with changes in demand as "variances from forecast were expected to be symmetrical and fall within a range of $20 million on an annual basis". However, based on the asymmetry and volatility in load actually experienced from fiscal 2005 to fiscal 2008 and the expectation that volatility may increase in future years, BC Hydro proposed that the net impact of load variances be included in the Non-Heritage Deferral Account starting in fiscal 2009, transferring the risk associated with changes in demand from BC Hydro to customers.[419] In Directive 31, the BCUC approved this request.[420] Direction No. 7 required the BCUC to continue to allow BC Hydro to defer the variances between actual and forecast cost of energy arising from differences between actual and forecast domestic customer load to the Non-Heritage Deferral Account.[421]

A revenue cap would recognize the continued uncertainty around the load forecast.[422] A revenue cap is also consistent with the approach that the BCUC has previously approved for FortisBC's natural gas and electricity utilities.[423] Accordingly, we believe that a revenue cap would be most suitable for BC Hydro.

11.4 Sharing Benefits Under PBR

The BCUC has asked for a discussion of a number of mechanisms that can be used to allocate the benefits achieved under PBR between BC Hydro and our customers. In this section, we address those mechanisms as well as others that may be included in a PBR plan as follows:

- Section 11.4.1 - PBR Term and Efficiency Carry-Over Mechanisms;

419 BCUC Decision, BC Hydro Fiscal 2009 to Fiscal 2010 Revenue Requirements (March 13, 2009), page 166.
420 BCUC Decision, BC Hydro Fiscal 2009 to Fiscal 2010 Revenue Requirements (March 13, 2009), page 232.
421 Direction No. 7, section 7 (c) (i).
422 BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), Appendix GG, page 13.
423 BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 21.

- Section 11.4.2 – Stretch Factors and Earnings Sharing Mechanisms; and
- Section 11.4.3 – Off-Ramps and Re-Openers.

It is important to recognize that mechanisms to allocate benefits achieved under PBR may affect the strength of the incentives provided to discover those benefits in the first place.

The strength of the incentives provided depends on the extent to which the amount of revenue recovered through rates is de-linked from a utility's costs, over the term of the PBR plan. Incentives are weak when the utility has the ability to pass along cost changes in the form of rate changes and are strengthened as this ability becomes more limited.[424]

It is important to recognize that the current cost of service approach to regulating BC Hydro already provides some limitation on the ability to pass along cost changes in the form of rate changes. For example, as BC Hydro's revenue requirements applications are submitted on a forecast basis and cover multiple years, rates are set independently of BC Hydro's actual costs over the test period. This means that unexpected cost pressures that arise during the test period must be managed and fully absorbed by BC Hydro within its existing approved revenue requirement, unless there is a regulatory mechanism in place to defer the impact.

Dr. Weisman explains that the strength of the incentives provided, depends on the mechanisms for allocating benefits and that adopting PBR does not automatically result in stronger incentives:

> "Whereas traditional cost-of-service regulation is frequently treated in the literature as a discrete alternative to PBR, these two types of regulatory regimes are best understood in terms of lying along a continuum based on the strength of the incentives for efficient performance. The textbook model of [cost of service

[424] Appendix FF, pages 8 to 10 and 49 to 50.

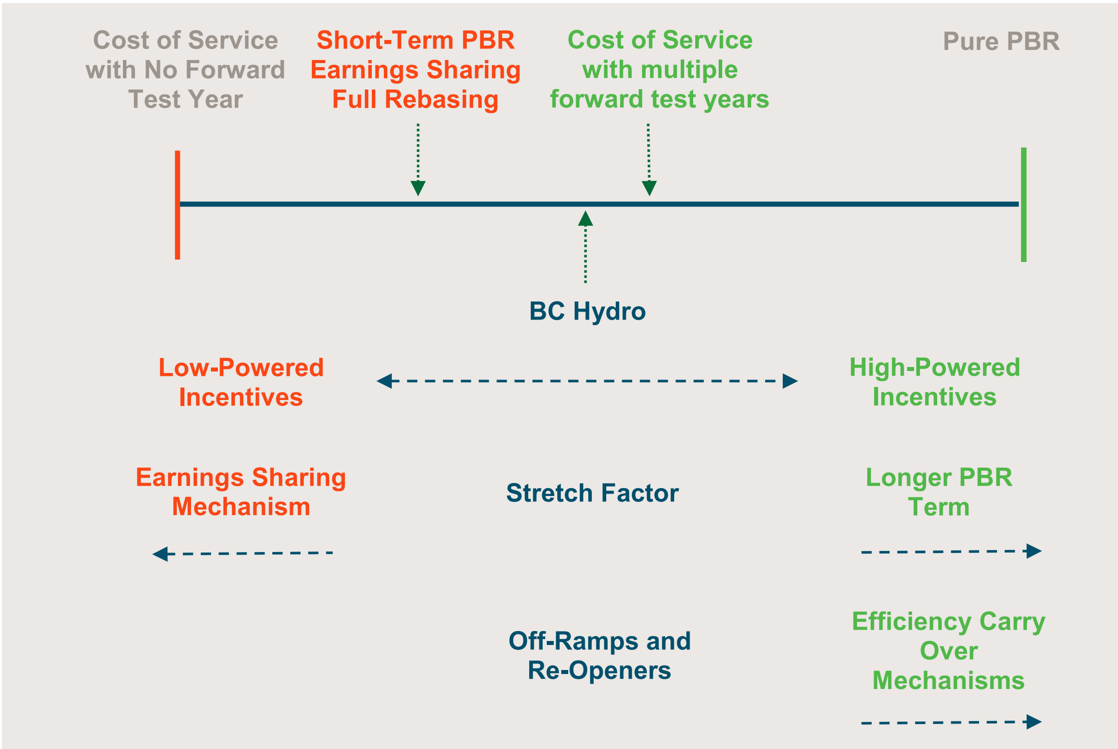
> regulation] with no regulatory lag[425] contemplates instantaneous rate reductions that serve to normalize excess returns. This regulatory regime lies at the far left on this continuum indicating extremely weak (low-powered) incentives. In contrast, long-term PBR with no earnings sharing or rebasing lies at the far right on this continuum indicating extremely strong (high-powered) incentives. Notably, [cost of service regulation] with a long regulatory lag may reside on this continuum to the right of a short-term PBR regime that incorporates a narrow deadband, pronounced earnings sharing and a full-rebasing of rates at the end of the PBR term. In this special case, [cost of service regulation] exhibits more high-powered incentives than PBR."[426]

Figure 11-3 indicates BC Hydro's current position on this continuum and shows how various mechanisms may increase, decrease or maintain the strength of incentives for efficient performance.

[425] In the context of PBR, "regulatory lag" means the length of time between rate reviews (e.g., the "regulatory lag for BC Hydro's Fiscal 2017 to Fiscal 2019 cost of service Revenue Requirements Application was three years). PBR aims to increase regulatory lag to strengthen financial incentives for efficient performance.

[426] Appendix FF, page 1.

Figure 11-3 Relative Incentive Power of BC Hydro's Current Regulatory Framework



In this section, we conclude that the PBR term should be at least five years as a longer term would provide stronger incentives. We also identify the trade-offs associated with using stretch factors or Earnings Sharing Mechanisms to manage the allocation of benefits during the PBR term. We conclude that a stretch factor would maintain the distinction between PBR and cost of service regulation and would not counteract the stronger financial incentives for efficient performance that PBR attempts to provide. If an Earnings Sharing Mechanism were to be included in the PBR plan, a mechanism with a "deadband" would provide stronger incentives than one which shares a set percentage of all earnings above or below the allowed net income. We also conclude that both financial and performance re-openers or off-ramps should be used. The financial triggers should be high enough to incent the vigorous pursuit of efficiencies while remaining low enough to provide a safeguard against excessive earnings or losses.

For simplicity, the discussion below focuses on benefits; however, it is important to note that the opportunity for customers to share in greater benefits is typically accompanied by increased exposure to risk. In other words, as customers receive a greater share of the benefits under PBR, through the mechanisms described below, they would also become exposed to more risks and the prospect of increased costs – through higher rates - should those risks materialize. Conversely, as BC Hydro's share of any benefits achieved under PBR increases, customers should become more insulated from potential risks and the corresponding costs.[427]

11.4.1 PBR Term and Efficiency Carry-Over Mechanisms

The BCUC has asked BC Hydro to discuss the appropriate length of a PBR term.

The PBR term refers to the period from the outset of PBR to "re-basing", when rates are "trued up" to reflect the utility's new cost of service. Through re-basing, some or all of the gains made under PBR are passed on to customers through lower rates in future years. The PBR term helps to determine how the benefits of PBR are shared between the utility and customers because it sets the minimum length of time that must pass before some or all of those benefits are transferred to customers, through re-based rates.

Two important considerations should inform the length of the PBR term:

- First, as the length of the PBR term increases, the incentives for the utility to achieve efficiencies also increases. This is because the utility retains those efficiencies for a longer period of time before some or all of the savings are transferred to customers, through re-based rates. [428]
- Second, the PBR term must be long enough to allow the utility to undertake the changes and investments necessary to discover and achieve additional efficiencies. If the PBR term is too short, re-based rates may reflect the costs of

[427] Appendix FF, page 11.
[428] Appendix FF, page 33.

additional investments made but not the expected efficiencies from those investments.[429] The BCUC has previously recognized this benefit of a longer PBR term, stating:

> "Efficiencies that require upfront costs in order to deliver a stream of benefits over a period of years are, in the Panel's view, more likely to be pursued under a PBR with a longer time period."[430]

Even with a longer PBR term, some cost effective investments may still be challenging to undertake if all of the benefits achieved from those investments are passed on to customers when rates are re-based. For example, towards the end of the PBR term, the payback period before rates are re-based becomes very short and some investments may require a payback period that is longer than the actual PBR term.[431] Efficiency Carry-Over Mechanisms address this issue by allowing the utility to carry-over a portion of its realized savings (or losses) into the next PBR term.[432]

The BCUC has previously recognized the potential value of Efficiency Carry-Over Mechanisms as a means of incenting the development of efficiency initiatives throughout the PBR term, provided that they balance the interests of the utility and its customers, are limited to specific investments where a longer payback period is required, and are applied on a case by case basis.[433]

BC Hydro's Previous Application under cost of service regulation was for a three-year period. As Dr. Weisman explains, the amount of time between when rates are re-based determines the relative strength of the incentives for efficiency between

[429] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 22.
[430] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 26.
[431] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 121-122.
[432] Appendix FF, page 42.
[433] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 128.

PBR and cost of service regulation.[434] In other words, all else equal, a PBR term of three years may provide no greater incentives for efficiency than the status quo.

Accordingly, BC Hydro suggests that the PBR term should be a minimum of five years and that Efficiency Carry-Over Mechanisms should be included in the PBR plan.

11.4.2 Stretch Factors and Earnings Sharing Mechanisms

While the PBR Term and Efficiency Carry-Over Mechanisms determine when and how rates are re-based so that the benefits achieved under PBR are transferred to customers, a PBR plan may also provide ways to share benefits with customers before rates are re-based. While the BCUC specifically asked BC Hydro to discuss potential Earning Sharing Mechanisms, we have also included a discussion on stretch factors, which are an alternative to Earnings Sharing Mechanisms.

As discussed in section 11.2.1, the objective of PBR is to provide stronger incentives than cost of service regulation so that the utility achieves new efficiencies that would not have otherwise been discovered. A stretch factor attempts to forecast these expected benefits in advance and immediately pass the savings on through lower rates to guarantee customers a share of the benefits from the stronger performance incentives that are expected under the PBR plan.[435] It is implemented by increasing the assumed productivity improvements in the PBR formula.[436] A stretch factor may be used to account for the relative efficiency for a utility at the beginning of a PBR plan.[437] In other words, if a utility is inefficient when it enters PBR, it may be subject to a high stretch factor, whereas a utility that has already been seeking out efficiencies would be subject to a lower stretch factor or none at all. Appendix T of this application provides a benchmarking study on BC Hydro's operating costs,

[434] Appendix FF, pages 1 and 33.
[435] State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities, MN Lowry, M Makos, J Deason, L Schwartz, page 4.2.
[436] Appendix FF, page 32.
[437] Appendix FF, pages 55 to 57.

completed by The Brattle Group. This study indicates that BC Hydro's operating costs compare favourably to those of an appropriate peer group and it should be considered when establishing whether any stretch factor is appropriate for BC Hydro.

While the stretch factor applied to each utility may be the same or different, it is set independent of the utility's performance during the PBR term. In other words, during the PBR term, the amount of benefits shared with customers, through the stretch factor, remains the same regardless of the actual level of efficiencies achieved by the utility.

Dr. Weisman observes that any stretch factor is ultimately a judgement call and there is no consensus that it is possible to develop a stretch factor in a scientifically rigorous manner.[438] As Dr. Weisman notes, regulators have taken different approaches to determining the appropriate stretch factor:

- the Alberta Utilities Commission has concluded that there is no definitive analytical source to determine the size of a stretch factor;
- the BCUC has determined that a stretch factor is judgement based and ordered FortisBC to conduct a benchmarking study to inform its judgement; and
- the Ontario Energy Board uses benchmarking studies to evaluate the efficiency of utilities relative to their peer group, in order to inform the selection of an appropriate stretch factor.[439]

While a stretch factor attempts to forecast benefits in advance so that they can be shared with customers immediately through lower rates, an Earnings Sharing Mechanism provides a way to share actual benefits achieved with customers, during the PBR term, before rates are re-based.[440] In this sense, a stretch factor and an Earnings Sharing Mechanism both provide ways to deliver benefits to customers and

[438] Appendix FF, page 55.
[439] Appendix FF, page 55.
[440] Appendix FF, page 36.

may be considered complementary to each other or alternatives to each other.[441] If a PBR plan already includes other mechanisms to share benefits and risks during the PBR term (such as a stretch factor or a Z factor, which is discussed in section 11.3 or regulatory accounts, which are discussed in section 11.5.8), an Earnings Sharing Mechanism may not be required.[442]

A key difference between an Earnings Sharing Mechanism and a stretch factor is that while a stretch factor is set independent of the utility's performance during the PBR term, an Earnings Sharing Mechanism, by sharing actual benefits achieved, is dependent on the utility's performance during the PBR term.

An Earnings Sharing Mechanism may be a set percentage of all earnings achieved above the allowed net income or it may be triggered or adjusted at certain thresholds so that the benefits retained by the utility, prior to rates being re-based, remain within acceptable bounds.[443] The utility's share may be constant or it may increase or decrease as certain thresholds are reached.[444] As discussed in section 11.4.3, off-ramps and re-openers are another option to keep the benefits retained by the utility within acceptable bounds. An Earnings Sharing Mechanism typically takes the form of a refund or an offset to rates or allowed revenue in the subsequent year.[445]

In *Designing Incentive Regulation*, Dr. Sappington suggests that establishing a "deadband" so that an Earnings Sharing Mechanism is not triggered until earnings reach a certain threshold above or below the utility's allowed net income, is preferable to a mechanism that shares a set percentage of all earnings above or below the allowed net income. A 2015 survey commissioned by the Edison Electric

441 BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 79.
442 Lowry et al., page A.1.
443 Appendix FF, pages 34 to 35.
444 Schmidt, page 73.
445 Schmidt, page 77.

Institute indicates that among utilities that have an Earnings Sharing Mechanism, most have a “deadband”. [446] As Dr. Sappington explains:

> “A common form of profit-sharing establishes a band…around the target rate of return. Within that band, the firm retains all of the returns it generates. Just outside of this band, sharing occurs... A sharing scheme like this has many attributes. In the immediate range around the target rate of return, the firm faces ideal incentives to foster cost reduction. Every dollar in reduced operating costs accrues to the firm, which provides strong incentives for the firm to minimize production costs. The incentives are less strong outside of this immediate range, but some incentives still remain.” [447]

The BCUC has previously approved both a stretch factor and an Earnings Sharing Mechanism. With regards to earnings sharing, the BCUC has stated that:

> “The Panel notes that the purpose of implementing a PBR mechanism is to provide an environment where efficiencies are created through actions initiated by the utility. Accordingly, there is an expectation that all things being equal, the Fortis utilities will, over the course of this PBR, generate efficiency savings resulting in earnings which allow them to exceed the approved [return on equity]… To deny the customer the opportunity of sharing these savings would not be in their interest.”[448]

While PBR can and should benefit all stakeholders, including customers, through the discovery of new savings not previously identified under cost of service regulation,[449] Dr. Weisman cautions that distributing benefits to customers during the PBR term may prevent those benefits from being discovered in the first place.[450] As explained in his article *Is There ‘Hope’ for Price Cap Regulation?:*

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[446] Of 25 utilities surveyed by Pacific Economics Group Research LLC, 13 have no Earnings Sharing Mechanism. Of the 12 utilities that have an Earnings Sharing Mechanism, only four do not have a “deadband”. (Alternative Regulation for Emerging Utility Challenges: 2015 Update, Pacific Economics Group Research LLC, Table 7).

[447] David E.M. Sappington, “Designing Incentive Regulation” *Review of Industrial Organization*, Volume 9, 1994, page 263.

[448] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 120 to121.

[449] Appendix FF, pages 12 to 13.

[450] Appendix FF, pages 48 to 50.

> "The key point, however, is that higher than normal earnings no longer (necessarily) imply rates that are not "just and reasonable." These higher than normal earnings may simply reflect the stronger incentives for efficient performance under price cap vis a vis earnings regulation. Should this be the case, these additional earnings would not exist but for the regulator's commitment to allow the regulated firm to be the residual claimant for its realized efficiency gains." [451]

Further as explained in *"Efficiency as a Discovery Process: Why Enhanced Incentives Outperform Regulatory Mandates":*

> "A common refrain is that because utilities have a "statutory obligation" to be efficient, any additional rewards for achieving efficient behavior through incentive regulation are unnecessary - and serve only to foster an inequitable distribution of efficiency gains between regulated firms and customers… the achievement of performance gains is first and foremost a "discovery process" in which more efficient operating practices and superior use of technology are learned over time. It is the recognition of this discovery process that leads to the conclusion that the efficiency gains realized under incentive regulation need not imply that the firm was knowingly inefficient under cost-of-service regulation. To the contrary, it is quite plausible that the firm under [cost of service regulation] was as efficient as it knew how to be."[452]

Weakening the incentives provided under PBR by incorporating an Earnings Sharing Mechanism should logically lead to a reduction in the assumed productivity improvements in the PBR formula, resulting in rates being higher than they otherwise would have been.[453] Earnings sharing may also reduce the actual efficiencies achieved under PBR, resulting in fewer actual benefits being passed on to customers through rate re-basing at the end of the PBR term.[454] Dr. Weisman notes that empirical analyses suggest that earnings sharing decreases the benefits

[451] Dennis L. Weisman, "Is There 'Hope' for Price Cap Regulation?" *Information Economics and Policy*, Volume 14(3), 2002 at 363-64.

[452] Dennis L. Weisman and Johannes P. Pfeifenberger, "Efficiency as a Discovery Process: Why Enhanced Incentives Outperform Regulatory Mandates," *The Electricity Journal,* Volume 16(1). January/February 2003, page 59.

[453] Appendix FF, pages 37 to 38.

[454] *Id*.

achieved under PBR[455] and that the Federal Communications Commission has recognized the trade-off between earnings sharing and assumed productivity improvements under the PBR formula. [456] Further, as noted in *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*:

> "Some [plans] contain menus of provisions from which utilities can choose…a utility might, for example, have a choice between (1) a low [productivity] factor and an earnings sharing mechanism and (2) a higher productivity factor and no earnings sharing."[457]

By weakening the incentives to discover new efficiencies and re-establishing a link between costs and rates, PBR with earnings sharing blurs the distinction between PBR and cost of service regulation. As the former Chair of the Massachusetts regulatory Commission once observed:

> "The [Massachusetts regulatory] commission decided that earnings sharing was not appropriate because it introduces many of the cost-of-service disincentives for efficiency that price cap regulation is designed to eliminate. The commission also did not want to have to rule on the prudence of investments in an increasingly risky and speculative industry, which would have been required for an earnings calculation. Also, earning sharing would require an annual review of earnings, which the Commission thought would be a significant administrative burden."[458]

As explained in section 11.2.2, a key difference between cost of service regulation and PBR is the role of the BCUC. Under cost of service regulation, the BCUC's role is to acquire information to determine which expenditures are prudent and which expenditures are imprudent. Under PBR, the BCUC's role would be to provide a framework and allow BC Hydro to manage its expenditures within that framework

455 Appendix FF, pages 38 to 39.

456 Federal Communications Commission, CC Docket No. 91-41, LEC Price Cap Performance Review, April 7, 1995.

457 Lowry et al., page 4.11.

458 Paul Vasington, "Incentive Regulation in Practice: A Massachusetts Case Study," *Review of Network Economics,* Volume 2(4), 2003, page 459.

without performing a detailed regulatory review that would second guess the decisions made. Dr. Weisman provides the following example which demonstrates why earnings sharing may blur this distinction:

> "A possible example of this phenomenon occurred in the aftermath of the epic floods that plagued the Midwest in the summer of 1993. After scrutinizing how Southwestern Bell allocated its resources in responding to this natural disaster, the Missouri Public Service Commission ordered cost disallowances that had the effect of moving the company's financial returns from the non-sharing range to the sharing range. These events prompted Southwestern Bell to move expeditiously across its five states with initiatives to eliminate earnings sharing from its price cap regulation plans."[459]

In other words, in the absence of an earnings sharing mechanism, the utility is assumed to have the appropriate financial incentives to make the most cost effective decisions. However, the presence of an earnings sharing mechanism may encourage second-guessing of those decisions so that the mechanism is triggered or results in a different allocation of costs. In this environment, PBR may not be distinct from cost of service regulation.

The Alberta Utilities Commission and the Ontario Energy Board have both rejected earnings sharing in favour of re-openers and off-ramps, which are discussed further in section 11.4.3. In its 2012 Decision, the Alberta Utilities Commission stated:

> "The Commission generally agrees with Dr. Weisman and Dr. Schoech that PBR plans with an [Earnings Sharing Mechanism] provide weaker incentives for efficiency gains, in part because costs and rates are no longer completely decoupled… In the Commission's view, the safeguards offered by an [Earnings Sharing Mechanism] do not outweigh the negative efficiency incentives that would be re-introduced into the PBR plan as a result of the incorporation of an [Earnings Sharing Mechanism]… Accordingly, the Commission finds that [Earnings sharing Mechanisms] as proposed by the parties, are not warranted as an additional safeguard and the disincentives

[459] Appendix FF, page 38, footnote 88.

> they will introduce are inconsistent with the objectives of PBR."[460]

Despite the economic drawbacks, sharing benefits during the PBR term may have some advantages. One potential advantage is to provide stability to the PBR plan by aligning the interests of the utility and its customers in a tangible way. [461] In other words, with earnings sharing, customers benefit from efficiencies discovered at the same time as the utility. As Dr. Weisman and Dr. Sappington observe in *Designing Incentive Regulation for the Telecommunications Industry:*

> Political support for a policy can be garnered when consumers benefit financially in direct, visible ways precisely when the regulated firm benefits, as is the case under earnings-sharing plans. Widespread political support for a policy can ensure its long-term survival and thus a continued flow of benefits to all parties. A sustained flow of moderate gains can often serve all parties better than can a short-lived spurt of particularly large gains." [462]

As Dr. Schmidt observes, striking the appropriate balance between providing incentives under PBR while assuring the stability and acceptance of the PBR plan among all stakeholders is a difficult challenge:

> "Economic theory and common sense tell us that a utility's best incentive to pursue productivity enhancing investments would be to allow the utility to retain 100 percent of the benefits of those investments. Anything less… will result in the utility foregoing some portion of what would otherwise be beneficial investments. Yet earnings sharing is a tool that can be seen to have different goals… The most challenging task faced by regulators and utilities is drawing the appropriate balance between following economic theory and these other goals."[463]

[460] Alberta Utilities Commission Decision 2012-237, Rate Regulation Initiative, Distribution Performance-Based Regulation (September 12, 2012), paragraphs 816, 818 and 822.

[461] Appendix FF, pages 36 to 37.

[462] David E. M. Sappington and Dennis L. Weisman, Designing Incentive Regulation for the Telecommunications Industry, Cambridge MA: The MIT Press, 1996, page 334.

[463] Schmidt, page 73.

Dr. Weisman observes that the economic evidence suggests that the costs of earnings sharing outweigh the benefits, but adds that some of the concerns with earnings sharing may be mitigated if it is temporary and intended to facilitate a successful transition from cost of service regulation to PBR:

> "Evaluating the various economic arguments both for and against earnings sharing, the weight of the evidence does not support including a traditional [earnings sharing mechanism] in a PBR plan. The net economic gains from replacing [cost of service regulation] with PBR that includes earnings sharing are likely to be small. Whereas regulators, consumer groups and sometimes even regulated firms may be comforted by the "safety net" that earnings sharing provides, it is the very presence of that "safety net" that undercuts the performance of PBR… The significant resources required to design and implement a PBR regime with earnings sharing would be difficult to justify when the expected benefits in terms of improved efficiency and innovation are so limited… it is conceivable that some of these concerns may be mitigated if PBR with earnings sharing is merely a transitional regulatory regime that represents an intermediate step along a dynamic path toward pure PBR… The outstanding question is whether such an intermediate step is warranted in light of the decisions of other Canadian regulatory commissions to forego earnings sharing for both electric power and telecommunications companies".[464]

Table 11-1 provides a summary of the advantages and disadvantages of stretch factors and Earnings Sharing Mechanisms.

[464] Appendix FF, pages 39 to 41.

Table 11-1 Advantages and Disadvantages of Stretch Factors and Earnings Sharing Mechanisms

	Advantages	Disadvantages
Stretch Factor	Does not weaken the incentive to find efficiencies because it is set independent of the utility's performance.	Ultimately a judgement call. No consensus that it is possible to develop a stretch factor in a scientifically rigorous manner.
Earnings Sharing Mechanism	Provides stability to the PBR plan by allowing customers to benefit from the discovery of new efficiencies at the same time as the utility. May help with the transition from cost of service regulation to PBR.	Weakens the incentives for efficiency because it re-establishes the link between rates and costs and is dependent on the utility's performance. Logically leads to a reduction in the assumed productivity improvements resulting in higher rates. May reduce the actual efficiencies achieved under PBR, resulting in fewer actual benefits being passed on to customers through rate re-basing at the end of the PBR term.

A stretch factor would maintain the distinction between PBR and cost of service regulation and would not counteract the stronger financial incentives for efficient performance that PBR attempts to provide. If an Earnings Sharing Mechanism were to be included in the PBR plan, a mechanism with a "deadband" would provide stronger incentives for efficient performance than one which shares a set percentage of all earnings above or below the allowed net income.

11.4.3 Off-Ramps and Re-Openers

Off-ramps and re-openers provide a way to intervene early, prior to rate re-basing, to adjust or reset the PBR plan, in the event that the benefits (or penalties) experienced by the utility during the PBR term, become excessive.

Re-openers provide an opportunity to investigate and modify a specific component of the PBR plan while off-ramps provide an opportunity to investigate and modify the entirety of the PBR plan, including possible termination of PBR for the utility.[465]

An off-ramp or re-opener that is triggered if a utility's earnings are above or below a certain threshold is an alternative to earnings sharing.[466] Thresholds are typically set

[465] Appendix FF, page 44 to 45.

using “basis points” where one basis point is equal to one one-hundredth of a percentage point (e.g., 100 basis points equals 1 per cent). Under this approach, if the benefits or costs realized under PBR are excessive, rather than transferring those benefits or costs to customers prior to rates being re-based, a re-opener or off-ramp can be triggered to adjust part or all of the PBR plan or to terminate the PBR plan.

Both the Alberta Utilities Commission and Ontario Energy Board favour this approach over earnings sharing during the PBR term.[467] As Dr. Weisman observes:

> “When the utility perceives that the probability of triggering these reopeners is negligible, which it will be with a sufficiently wide deadband, it will have virtually the same incentives for superior performance as if it were operating under a pure PBR regime. Nonetheless, sufficient earnings safeguards remain in place should returns diverge too far from target levels.”[468]

The BCUC has recognized the importance of balanced thresholds for triggering off-ramps or re-openers, stating:

> “With respect to the financial trigger… it should strike a balance between being high enough to incent the utility to vigorously pursue efficiencies and savings while being low enough to provide a safeguard for customers and the utility if either profits or losses become excessive”.[469]

The Alberta Utilities Commission has set its financial trigger for a re-opener at +/- 300 basis points (3 per cent) for two consecutive years or +/- 500 basis points (5 per cent) in any one year. The Ontario Energy Board has set its financial trigger at +/- 300 basis points (3 per cent). The BCUC set FortisBC’s financial trigger at

466 Appendix FF, pages 41 to 42.
467 *Id.*
468 *Id.*
469 BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 155.

+/- 150 basis points (1.5 per cent) for two consecutive years or +/- 200 basis points (2 per cent) in any one year, after accounting for 50 per cent earnings sharing.[470]

The BCUC and the Ontario Energy Board have also determined that it is appropriate to use off-ramps or re-openers to address unacceptable performance levels,[471, 472] however, the Alberta Utilities Commission has determined that it has appropriate tools to address service quality performance issues and that a degradation in service quality should not trigger a re-opener or off-ramp.[473]

BC Hydro believes that both financial and service quality triggers are appropriate. With respect to financial triggers, we agree with the BCUC that a balance should be struck between being high enough to incent the vigorous pursuit of efficiencies and being low enough to provide a safeguard against excessive profits or losses. If this balance is struck, using off-ramps or re-openers rather than an Earnings Sharing Mechanism, to keep earnings within acceptable bounds would maintain the distinction between PBR and cost of service regulation and would not counteract the stronger financial incentives for efficient performance that PBR attempts to provide.

We believe that the appropriate financial and performance triggers for BC Hydro should be determined through a PBR application process.

[470] *Id.*
[471] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), pages 157 to 158.
[472] Ontario Energy Board, Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012, page 13.
[473] Alberta Utilities Commission, Rate Regulation Initiative Distribution Performance-Based Regulation, September 12, 2012, Decision 2012-237, section 8.1.1.

11.5 Managing Capital and Other Costs Under PBR

As discussed in section 11.3.1, a PBR plan may have "adders" to the formula or "carve outs" from the formula that all interact to determine how costs are managed. It is critically important for the assumed productivity improvements in the PBR formula to reflect the capital investment requirements of the utility and for the "adders" or "carve outs" to appropriately capture expenditures that are not covered by the PBR formula, without becoming excessive.

There are inherent trade-offs with any approach. PBR aims to provide the utility with stronger incentives to discover new efficiencies and increased autonomy from detailed regulatory reviews, but the revenue cap set by the PBR formula may not adequately fund all of the utility's expenditures. "Adding" to the formula or "carving out" certain costs from the formula may provide more adequate funding for necessary investments. When costs are "carved out", the BCUC and interveners may have more ability to review those expenditures; however, the incentives and discretion provided by the PBR plan are decreased, which could limit the incremental efficiencies achieved.

Although the BCUC has asked BC Hydro to specifically discuss how capital spending could be managed under PBR, the discussion below addresses a number of our cost components as similar issues and trade-offs exist in a number of areas.

Table 11-2 provides a summary of this discussion, indicating the cost components that could likely be managed through the PBR formula, potentially with some "adders" or "carve outs" as well as cost components that may need to be "carved out" entirely.

Table 11-2 Management of Various Cost Components under a PBR Plan

Likely subject to PBR formula with some "adders" or "carve outs"	Various options – approach best determined through PBR application process	Likely "carved out" from the PBR formula entirely
Operating Costs	Capital Expenditures	Cost of Energy
		Taxes
		Finance Charges
		Demand Side Management
		Revenues and Subsidiary Net Income

11.5.1 Capital Expenditures

BC Hydro's capital expenditures include power system growth, redevelopment, dam safety, and sustaining expenditures along with technology, properties and fleet investments. Capital expenditures do not impact rates until a capital project is placed in service and becomes a capital addition, and the expenditure is amortized.

Our infrastructure is aging, requiring ongoing investments to maintain the safety and reliability of the electricity system. In addition, we must meet growing local, regional and system-wide demands from our customers as well as increased customer service expectations and changing technology requirements. To meet these requirements, we prepare an annual Capital Plan, which provides guidance and constraints for bottom-up capital planning.

The following issues would need to be carefully considered when designing an approach to capital expenditures under PBR for BC Hydro:

- Scope - Capital investment requirements can change significantly within a short timeframe due to project investigation work, market conditions, resource availability and scheduling, engagement with stakeholders and changing regulatory and environmental requirements;
- Asset Health – Historical capital expenditures are not an accurate predictor of future capital expenditures as future requirements are driven by asset health

and where assets are in their lifecycle. As explained in *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*:

> "…in the short to medium run a utility's productivity growth is driven by the position of the utility in the cycle of asset replacement. Productivity growth will be slower to the extent that the need for replacement [capital expenditures] is large relative to the existing stock of capital."[474]

- Risk – If short-term asset replacements are deferred due to insufficient funding, increased costs and risks will develop over the long-term; and
- Customer Demand – BC Hydro has an obligation to serve all customers.

In support of their *Next Generation PBR Plan* which was filed in 2016 with the Alberta Utilities Commission, EPCOR commissioned Dr. Sappington and Dr. Weisman to review options for the treatment of capital expenditures in PBR plans. In their report titled *Assessing the Treatment of Capital Expenditures in Performance-Based Regulation Plans*, which is included as Appendix GG, Dr. Sappington and Dr. Weisman identified seven potential PBR-based options. The plans range from "carving out" all capital expenditures from the PBR formula and conducting a cost of service based review to including all capital expenditures within a PBR formula. A number of in-between options are also explored with trade-offs between the incentives provided, the degree of regulatory oversight and the level of certainty that funding will be sufficient to support the required investment.

The BCUC has previously recognized the potential consequences of "carving out" excessive amounts of supplemental capital, stating:

> "In the Panel's view, the more capital excluded from formula spending, the fewer benefits of PBR accrue to ratepayers and shareholders alike. Excluding significant amounts of capital reduces the ability of the utility to achieve operational efficiencies. However, it also provides opportunities for a utility

[474] Lowry et al., page B.10.

> to game the system such as by combining smaller projects into larger projects that will be excluded from the formula."[475]

Dr. Weisman also cautions that a PBR plan which "carves out" all capital expenditures from the PBR formula may encourage inefficient capital-labour substitution.[476] For example, capital upgrade projects could replace more cost effective operating maintenance programs.

While a broad and inclusive approach to capital may be preferable, the BCUC has also determined that a less inclusive approach may be appropriate in certain circumstances, stating:

> "By applying the formula driven spending envelope to smaller capital projects only, and providing for funding of larger capital projects outside of the formula, there is less risk of needed projects being underfunded. In addition, this approach also mitigates the risk of lumpy capital spending patterns by excluding any projects that are large enough to potentially distort the amount of formula spending and result in gains or losses to either ratepayers or shareholders."[477]

Dr. Sappington and Dr. Weisman evaluated each potential approach to managing capital expenditures based on the degree to which it:

- Avoided elements of traditional rate of return regulation and provided strong incentives for efficiency;
- Provided sufficient funding for required capital investments in a comprehensive and principled manner; and
- Was simple, transparent, and reduced the regulatory burden for all parties relative to cost of service regulation.

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[475] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 170.

[476] Appendix FF, page 46

[477] BCUC, FortisBC Energy Inc. and FortisBC Inc. Multi-Year Performance Based Ratemaking Plans for 2014 through 2019 Approved by Decisions and Orders G-138-14 and G-139-14 Capital Exclusion Criteria under PBR – Compliance Filing, page 7 to 8.

Table 11-3 provides a summary of this evaluation.

Table 11-3 Assessing the Treatment of Capital Expenditures in PBR Plans

Option	Strong Incentives	Sufficient Funding	Reduced Regulatory Burden
A. Operating costs are subject to PBR but capital costs are subject to cost of service regulation with a mid-term update.	No	Yes	No
B. Same as A but no mid-term update.	No	Yes	No
C. All costs subject to PBR with a "K" factor adjustment to reflect the costs of unique lifecycle replacement projects or projects required by external parties as well as projects inadequately funded by the PBR formula. Projects included in the "K" factor must exceed a non-aggregated materiality threshold. A true-up between forecast and actual capital costs occurs for "K" factor projects only.	Possibly	Yes	Possibly
D. Same as C but the "K" factor does not include projects inadequately funded by the PBR formula and the materiality threshold is aggregated.	Possibly	No	Possibly
E. All costs subject to PBR with a "F" factor adjustment to reflect the extent to which the PBR formula is insufficient for required capital investments and a "K" factor adjustment to reflect unique lifecycle replacement projects or projects required by external parties. The "F" factor adjustment is set at the beginning of the PBR term and does not change while the "K" factor can be trued up annually to reflect actual capital costs.	Yes	Possibly	Yes
F. Same as E but the "K" factor is not trued up annually. Rather, a mid-term review, limited to unique lifecycle replacement projects that were not known at the start of the PBR term, is conducted to determine the required "K" factor adjustment.	Yes	Possibly	Yes

Option	Strong Incentives	Sufficient Funding	Reduced Regulatory Burden
G. All costs subject to PBR but the “X” factor (productivity factor) for capital is determined based on a moving average of the company’s historical capital expenditures. No “F” or “K” factor adjustments are permitted unless corrections are required in response to unforeseeable “Z” factor events.	Possibly	No	Yes

Table 11-3 and Appendix GG provide an indication of the relative merits of each approach. We have not attempted to evaluate which of these options may be most appropriate for the management of capital expenditures under a PBR plan for BC Hydro. This evaluation should be conducted through a PBR application process.

The best way to manage capital expenditures under a PBR plan may be to adopt different approaches for different types of capital expenditures. As Dr. Weisman observes:

> “The specific attributes of each element of production may give rise to either a different form of PBR (price caps versus revenue caps) or specific design attributes for the PBR regime. For example, generation is typically characterized by more “lumpy” capital investments and this may require special provisions for capital within the PBR regime (e.g., capital trackers). Conversely, the generally smoother investment profiles commonly associated with transmission and distribution elements may allow for a more limited scope of special provisions for capital in the PBR regime.” [478]

The Alberta Utilities Commission has revised the extent to which special provisions like “adders” or “carve outs” are necessary to accommodate transmission capital expenditures within a PBR plan.

In 2009, the Alberta Utilities Commission approved a formula-based ratemaking plan (similar to PBR) for Enmax, which included transmission expenditures, stating:

[478] Appendix FF, page 30

> "The Commission agrees… that [a PBR] mechanism is not as well suited to transmission in Alberta as it is to distribution. Nevertheless, the Commission considers that it is in the public interest to approve an incentive regulation plan for transmission in order to promote efficiency of operations and efficiency of the regulatory process. The Commission has recognized some of the effects of the structure of the regulatory framework for transmission in determining the X factor. The structure of the regulatory framework for transmission also requires specific adjustments in [a PBR] plan to recognize capital additions each year." [479]

However, in 2012, Enmax applied to re-open the plan for its transmission function as its return on equity was below the established threshold. In its 2014 Decision on this application, the Alberta Utilities Commission stated:

> "Accordingly, the Commission finds that the significant increase in capital additions beginning in 2010 was the event that triggered the re-opener. Following… the increase in capital additions, the [growth] factor was unable to achieve its intended objective of allowing for the recovery of the revenue requirement related to the transmission capital expenditures made by ENMAX during the [plan] term that exceed the revenue available from rate increases permitted under the I-X mechanism." [480]

Finally, in 2012, the Alberta Utilities Commission denied a proposal by EPCOR to include transmission services in its PBR plan, opting instead to continue to regulate transmission under cost of service regulation.[481] However, Dr. Weisman notes that this decision may be re-visited in the future.[482]

It may also be appropriate to adopt a different approach for managing generation, transmission or distribution capital expenditures that are approved through processes that are separate from the PBR plan. Currently BC Hydro must obtain a

[479] Alberta Utilities Commission Decision 2009-035, Enmax Power Corporation, 2007-2016 Formula Based Ratemaking (March 25, 2009), paragraph 222.
[480] Alberta Utilities Commission Decision 2014-100, Enmax Power Corporation Formula-Based Ratemaking Transmission Tariff Re-opener (April 15, 2014), paragraph 54.
[481] Alberta Utilities Commission Decision 2012-237, Rate Regulation Initiative, Distribution Performance-Based Regulation (September 12, 2012), paragraphs 68 to 74.
[482] Appendix FF, page 30.

separate Certificate of Public Convenience and Necessity (**CPCN**) for significant system extensions. BC Hydro also seeks acceptance of capital expenditure schedules under section 44.2 of the *Utilities Commission Act* for many other large capital investments.[483] The BCUC has previously rejected the idea of aligning CPCN criteria with the criteria to establish which capital expenditures should be "carved out" from the PBR formula, stating:

> "…the use of [Certificate of Public Convenience and Necessity] criteria as an exclusion criterion for the PBR formula is arbitrary. Further, the CPCN requirements do not differentiate between routine capital projects and projects that are not routine. Therefore, they are not a good indicator of the exogenous nature of the capital project." [484]

BC Hydro agrees that criteria established for one purpose cannot be arbitrarily used for another purpose. However, it may be appropriate to consider how criteria may be aligned to allow for a specific "adder" or "carve out" within a PBR plan for projects that have obtained a CPCN. In the absence of a specific mechanism, a project may be approved through a CPCN proceeding and subsequently captured within the PBR formula. The PBR formula may produce a rate adjustment that is not sufficient to fully fund the cost of that project. Conversely, a project may be considered in determining the productivity factor for the PBR formula and then not proceed because it was not approved in a separate proceeding. In this case, the funding envelope produced by the PBR formula may be too large.

11.5.2 Cost of Energy

BC Hydro's Cost of Energy are largely uncontrollable and we expect that it may be appropriate to "carve out" the cost of energy from the PBR formula.

BC Hydro's costs of energy include:

- Water rentals;

[483] BC Hydro Initial Proposal, Review of the Regulatory Oversight of Capital Expenditures and Projects, page 1.
[484] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 171.

- Market electricity purchases;
- Natural gas for thermal generation;
- Domestic transmission costs;
- Columbia River Treaty Related Agreements;
- Water rental remissions;
- Independent Power Producers (**IPPs**) and Long-Term Commitments
- Costs to supply Non-Integrated Areas;
- Gas and other transportation costs;
- Market electricity purchases;
- Surplus sales; and
- Net Purchases (Sales) from Powerex.

Water rentals are set by the *Water Sustainability Act* and are similar to taxes in that government sets the rental rates and receives the rental revenues. The generation of energy subject to water rentals is also based on a number of non-controllable factors such as water inflows, storage availability and system load requirements.

Market electricity purchases are determined by forward market prices and purchase volume. BC Hydro is generally a price-taker on any market purchases and the amount of market energy that we acquire is influenced by a number of volatile factors such as weather and water inflows.

Natural gas commodity costs to supply our thermal generating facilities are based on system load requirements, gas volumes and market commodity prices which are beyond our control.

Domestic Transmission costs include costs associated with surplus sales as well as our obligations under the Skagit Valley Treaty. Costs related to Columbia River

Treaty Agreements, Surplus Sales and Remissions represent offsets to our energy costs and are not directly controllable by BC Hydro.

Costs related to IPPs and Long-Term Commitments are generally long term supply contracts with established prices and fixed take or pay terms. As discussed in our Previous Application and in Chapter 4, section 4.3.2 of this application, we have taken a number of steps to manage the volume and costs of our IPP commitments.[485] However, further cost reduction opportunities are limited as government directions have mandated cost recovery in rates for most energy supply contracts.

BC Hydro also incurs costs to supply non-integrated areas, including IPP supply costs and costs to provide service through diesel generation. IPP supply costs are generally fixed and diesel fuel costs are determined by the spot fuel market where BC Hydro is a price-taker.

Based on the issues discussed above, we expect that it may be appropriate to “carve out” the cost of energy from the PBR formula and have those costs flow directly to rates through the “Y” factor.

11.5.3 Operating Costs

As discussed in section 5.5.1 of this application, BC Hydro considers base operating costs to be the key measure for the assessment of our overall operating costs.[486] The operating costs that are excluded from base operating costs vary significantly from year to year and we expect that it would be appropriate to include those costs in the “Y” factor. Therefore, the remainder of this section is focused on base operating costs.

[485] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, section 1.5.6.

[486] Base operating costs are defined as “personnel, materials and external services expenses included in income that are incurred in the day to day operating of BC Hydro’s electric utility, net of recoveries, capitalized costs and reclassification adjustments.” Further information is provided in Chapter 5, section 5.5.1.

Labour costs account for approximately 52 per cent of total base operating costs, services approximately 42 per cent, and materials and supplies approximately 6 per cent. If PBR were adopted for BC Hydro, the labour cost index used to help determine the inflation factor would need to recognize that BC Hydro is subject to the bargaining mandate for the broader public sector as determined by the British Columbia Public Sector Employers Association.

As discussed in our Previous Application, BC Hydro has already taken significant steps to reduce its base operating costs under cost of service regulation[487] and as a result, opportunities for further reductions may be limited.

In addition, some base operating costs are beyond our control and would likely need to be included in a "Y" factor. Some examples include:

- Storm restoration costs;
- Regulatory compliance costs (e.g., Mandatory Reliability Standards and North American Electric Reliability Corporation Critical Infrastructure Protection);
- Mandatory memberships (e.g., Western Electricity Coordinating Council);
- Employer taxes such as the employer health tax or the Canada Pension Plan premium; and
- Current service pension costs.

In addition, there are some cases where operating costs would need to be adjusted for one-time events or increases through a "Z" factor. Some examples include:

- New regulatory compliance costs (e.g., new WorkSafe BC requirements or new environmental standards); and
- Significant weather events.

[487] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, sections 1.5.2 and 1.6.1.5.

11.5.4 Taxes

BC Hydro pays school taxes, taxes related to energy purchase agreements that are classified as capital leases for accounting purposes, and grants-in-lieu to municipal, regional district and local governments.

School taxes are based on assessed property values and tax rates established by government. Grants-in-lieu are based on assessed property values as well as revenue grants equal to 1 per cent of gross revenue from domestic energy sales, which are based on forecast sales revenue increases. We expect that these costs will increase much faster than inflation in the future. Given this and the fact that these costs are uncontrollable, we expect that it would be appropriate to include all taxes within the “Y” factor.

11.5.5 Finance Charges

Finance charges reflect the cost of BC Hydro’s debt portfolio, and are primarily composed of interest charges on debt, excluding sinking fund income, charges capitalized to unfinished construction, and interest allocated to regulatory accounts.

Interest costs are heavily influenced by the nature of our debt portfolio, long and short term interest rates and Canada/US exchange rates.

As discussed in our Previous Application, BC Hydro has implemented a debt management strategy, which aims to lock in interest rates by entering into future debt hedges to mitigate interest rate risk. Any gains or losses from future debt hedges are recorded in the Debt Management Regulatory Account and amortized into rates over the remaining term of the associated long-term debt issuances.[488]

As discussed in section 11.3, an inflation index may use forecast values, forecast values with a “true-up” or actual values from the previous year. The selected approach under a PBR plan for BC Hydro would need to recognize that actual interest rates have varied significantly from forecast interest rates in recent years. If

[488] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, section 7.5.13.

the inflation index is not based on actual values or does not include a “true-up” mechanism, we expect that finance charges would need to be “carved out” from the PBR formula through the “Y” factor to avoid the potential for significant gains or losses to BC Hydro if there continues to be a large difference between actual and forecast interest rates.

In addition, as BC Hydro’s overall debt is influenced by its amount of capital expenditures, we expect that if some or all capital expenditures are “carved out” from the PBR formula, finance charges may need to be “carved out” as well.

11.5.6 Demand Side Management

BC Hydro has undertaken a broad range of demand side management programs over the past 25 years. These programs help our customers reduce their energy consumption and save money, while also reducing our need to acquire new energy supply resources. While there are a range of options to manage demand side management expenditures under a PBR plan, the most common approach is to “carve out” these expenditures from the PBR formula.

BC Hydro’s demand side management plan is influenced by government policy and legislation. For example, the Demand- Side Measures Regulation under the *Utilities Commission Act* defines measures that we are required to undertake for our demand side management plan to be considered adequate and also provides detailed guidance on how the cost-effectiveness of demand side management measures is to be determined.

In addition, government sets policy targets for demand side management, such as the *Clean Energy Act* objective to reduce the expected increase in demand for electricity by the year 2020 by at least 66 per cent.

Under section 44.2 of the *Utilities Commission Act*, BC Hydro may apply to the BCUC for a public interest acceptance of demand side management expenditures by filing a demand side measures expenditure schedule. The BCUC may accept or reject BC Hydro's proposed expenditure schedule but cannot modify programs or require a specific level of spending.

Demand side management expenditures are deferred to the Demand Side Management Regulatory Account and amortized into rates over a 15-year period. As explained in Chapter 10 of our Previous Application, we reduced our demand side management expenditures and eliminated or revised programs that were not cost effective, to take pressure off rates and to reflect reduced forecast system needs.

The BCUC issued the following directives with regards to demand side management in its Decision on our Previous Application:[489]

- Directive 20 accepted BC Hydro's proposed demand side management expenditure schedule;
- Directive 21 recommended that BC Hydro consider more targeted programs directed at residential customers in the next demand side management application; and
- Directive 23 directed BC Hydro to provide an update on how concerns raised regarding demand side management for Non-Integrated Areas have been addressed in its next demand side management application.

Including demand side management expenditures within a PBR formula may run counter to Directives 21 and 23 and to the adequacy requirements as set out in the Demand Side Measures Regulation. Programs developed to broaden access or target specific customer groups may be less cost effective than other opportunities available to BC Hydro. As a result, including demand side management expenditures within the PBR formula could incent adjustments that limit, rather than expand, customer access to demand side management programs.

[489] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 117.

In addition to traditional demand side management, BC Hydro has recently been exploring low carbon electrification programs. These programs support the reduction of greenhouse gas emissions by encouraging the use of electricity instead of more carbon intensive fuels. Low carbon electrification expenditures, meeting requirements under the *Greenhouse Gas Reductions Regulation* under the *Clean Energy Act*, are considered to be prescribed undertakings.[490] The *Clean Energy Act* requires the BCUC to set rates that allow for cost recovery of prescribed undertakings.[491]

The options to manage demand side management spending within a PBR plan are similar to the options to manage capital expenditures with the same inherent trade-offs between the incentives provided, the degree of regulatory oversight and the level of certainty that funding will be sufficient to support the desired investments. While Table 11-3 provides a wide range of options, an approach similar to options A or B, where demand side management expenditures are completely "carved out" of the PBR formula, appears to be the most common approach.[492] This is also the approach that the BCUC has adopted for FortisBC.[493] Accordingly, we expect that it would be appropriate to "carve out" demand side management expenditures from the PBR formula.

11.5.7 Revenues and Subsidiary Net Income

As outlined in Chapter 8 of this application, BC Hydro receives miscellaneous revenues, inter-segment revenues, revenue from other utilities and net income from its subsidiaries Powerex and Powertech. [494] These items are uncontrollable and we expect that it would be appropriate to capture them through the "Y factor."

490 Greenhouse Gas Reduction Regulation, section 4.
491 *Clean Energy Act*, section 18.
492 A survey by IndEco Strategic Consulting and Navigant Consulting canvassed 12 leading jurisdictions across North America and found that none of them included demand side management as part of the PBR formula. (DSM in North American gas utilities, IndEco Strategic Consulting and Navigant Consulting, page 6).
493 BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 250.
494 BC Hydro, Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, pages 8-11 and 8-12.

11.5.8 Regulatory Accounts

The BCUC's guidelines identify four situations where it is appropriate to use regulatory accounts:[495]

- To capture the variance between forecast costs or revenues and actual costs or revenues (variance accounts);
- To defer recovery of costs to a future period, when the benefits of those cost are realized, if they provide long-term benefits to current and future ratepayers (benefit matching accounts);
- To mitigate rate shock resulting from the impact of large forecast one-time items or resulting from forecast overall general rate increases or to reduce rate volatility (rate smoothing accounts); and
- To recover or refund certain uncontrollable costs or revenues that materialize after the occurrence of an unforeseeable event (retroactive expense account);

The BCUC's guidelines also recognize that there may be other situations that require a regulatory account. BC Hydro has two types of accounts that fall into this category:[496]

- Non-cash provision accounts: To recognize a non-cash provision in order to create a regulatory asset to match an accounting liability that is required under the accounting standards, prior to the actual expenditure of funds; and
- IFRS transition accounts: To defer the impact of a required change in the accounting treatment of costs to ensure proper recovery of those costs in rates.

The existing balances in BC Hydro's regulatory accounts should not be subject to a PBR formula because they represent past costs and their recovery in rates is required by Direction No. 8 to the BCUC. BC Hydro has no ability to find further

[495] BCUC Regulatory Account Filing Checklist (May 3, 2017).
[496] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, pages 7 to 9.

efficiencies on costs that have already been incurred. Accordingly, the amortization of existing balances from BC Hydro's regulatory accounts should remain unchanged and flow into rates through the "Y factor."

With regards to the future use and amortization of regulatory accounts, the adoption of PBR would not change the period of time over which the benefit of a particular service or asset accrues to ratepayers, the requirement for loss provision liabilities or the potential for non-controllable financial impacts from a change in the accounting standards applicable to BC Hydro. Therefore, BC Hydro expects that there would be no reason to consider changes to its benefit matching accounts, non-cash provision accounts or IFRS transition accounts under PBR.

With regards to BC Hydro's variance accounts, these accounts reflect examples of appropriate "Y" factor costs, as discussed throughout section 11.5. There are various recovery mechanisms and periods in place for these accounts. In its Decision on FortisBC's 2014 to 2018 PBR Application, the BCUC noted that there must be a mechanism to manage variances between forecast and actual costs captured by the "Y" factor but determined that regulatory accounts are not necessarily required in all cases as small variances could be "trued-up" each year without a significant rate impact.[497] BC Hydro does not believe that the adoption of PBR should prompt a change to recovery mechanisms or periods and that opportunities to "true-up" small variances on an annual basis are best explored within a PBR application process.

BC Hydro does not currently have any retroactive expense regulatory accounts. Under a PBR plan, any unforeseeable costs or revenues would be captured by a "Z" factor and if those costs or revenues were to be recovered in rates over a period longer than one year, a retroactive expense regulatory account may be required.

[497] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), pages 107 to 109.

With regards to rate smoothing, as part of the Comprehensive Review, BC Hydro ceased using the Rate Smoothing Regulatory Account at the end of the third quarter of fiscal 2019. BC Hydro is not proposing to smooth rates over the fiscal 2020 to fiscal 2021 test period and is requesting BCUC approval to close the Rate Smoothing Regulatory Account.

11.6 Monitoring the PBR Plan

In response to the BCUC's request, this section provides a list of potential key performance indicators to assist BC Hydro and the BCUC to evaluate progress during the PBR term as well as a proposed Annual Review process.

11.6.1 Potential Key Performance Indicators

In its Decision on FortisBC's 2014 to 2018 PBR Application, the BCUC determined that earnings must be linked to the achievement of key performance indicators (also referred to as service quality standards) so that there are consequences if efforts to discover further efficiencies result in failure to achieve reasonable performance. Specifically, the BCUC stated:

> "The PBR is being approved with incentives for the utility to create efficiencies and reduce unnecessary cost. However, if [operating and maintenance costs] and maintenance capital are too tightly constrained this may result in a degradation of key service level areas. Therefore, the Panel considers that incentives related to reducing costs and creating efficiencies need to be counter balanced to ensure this occurs without a degradation of service levels as measured by [service quality indicators]." [498]

[498] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 133.

The BCUC also determined that service quality indicators must be balanced and fully reflect the obligations legislated under the *Utilities Commission Act* to provide "reasonable, safe, adequate and fair service."[499]

BC Hydro's Service Plan has 12 performance metrics which correspond to four goals around safety, reliability, affordability and clean energy. These performance metrics are developed in consultation with the Government of B.C. and approved by BC Hydro's Board of Directors.

In its Decision on FortisBC's 2014 to 2018 PBR Application, the BCUC set out 10 Approved Service Quality Indicators for the electric utility in Table 2.26.[500] Of these 10 indicators, five identical or similar metrics are already contained within BC Hydro's Service Plan (All Injury Frequency Rate, Customer Satisfaction Index, System Average Interruption Duration Index, System Average Interruption Frequency Index and Key Generating Facility Forced Outage Factor). The remaining five metrics are focused on emergency response and customer service.

Additional key performance indicators focused on customer service and emergency response may be appropriate for BC Hydro. With regards to customer service metrics, BC Hydro internally tracks both First Contact Resolution and Telephone Service Factor. However, Billing Index and Meter Reading Accuracy would not be appropriate key performance indicators as the installation of smart meters means that BC Hydro is at nearly 100 per cent on both of these metrics. A more appropriate metric may be per cent of bills issued on actual reads, which is already reported to the BCUC on a quarterly basis through our Summary Report of Customer Complaints and Consecutive Estimates.

BC Hydro's Service Plan contains additional metrics compared to those approved for FortisBC. We believe that the Progressive Aboriginal Relations Designation, Project

[499] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), pages 142 to 143.

[500] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 147.

Budget to Actual Cost, Zero Fatality and Serious Injury and Timely Completion of Corrective Actions metrics would also be appropriate to evaluate progress during the PBR term.

The Affordable Bills, Clean Energy and Energy Conservation Portfolio metrics would likely not be appropriate for evaluating progress during the PBR term. With regards to the Affordable Bills metric, a PBR plan would already provide incentives to discover efficiencies to achieve competitive rates and as explained above, key performance indicators are meant to counterbalance these incentives, not reinforce them. With regards to the Clean Energy and Energy Conservation Portfolio metrics, the *Clean Energy Act* already contains legislative requirements with regards to energy generation and conservation. A key performance indicator would not provide any additional incentive to meet these objectives relative to the existing legislative requirements.

11.6.2 Annual Review Processes

In its Decision on FortisBC's 2014 to 2018 PBR Application, the BCUC set out an Annual Review process that would include:[501]

- An evaluation of the PBR Plan and identification of deficiencies and concerns with recommendations to address;
- A review of current year projections and upcoming year forecasts;
- Identification of efficiency initiatives that require a payback period extending beyond the PBR plan and whether these initiatives should be captured through an Efficiency Carry-Over Mechanism;[502]
- A review of unforeseen events that should be put to the BCUC for decision on exclusion (through the "Z" factor); and

501 BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 179-180.

502 Refer to related discussion in section 11.3.2 of this report.

- A review of performance on key performance indicators and identification of any key performance indicators that should be reviewed.

We believe that the above scope is appropriate and that a similar Annual Review process would be suitable for BC Hydro.

11.7 Implementing a PBR Plan

The BCUC has asked BC Hydro to consider an implementation timetable for a PBR plan including a proposed schedule of consultation with representatives of key customer groups and BCUC staff.

Dr. Schmidt cites Edison Electric Institute's *Performance-Based Regulation: Design and Implementation Strategies* to provide the following guidance regarding the implementation of a PBR plan:

> "Do not expect the PBR process to be quick or routine. The process of change is not simple or easy. Utilities have found that their first PBR case involved a tremendous amount of regulatory work. The initial PBR case can look very much like a full-blown general rate case with a full cast of intervenors."[503]

11.7.1 Potential Implementation Timetable

BC Hydro has filed a cost of service Revenue Requirements Application for fiscal 2020 and fiscal 2021. BC Hydro suggests that the BCUC provide its decision on the adoption of PBR for BC Hydro in its decision on this Revenue Requirements Application.

As discussed further in section 11.8 below, we believe that BC Hydro should continue to be regulated through cost of service regulation at this time.

However, if the BCUC decides to adopt PBR for BC Hydro, following this Revenue Requirements Application proceeding, BC Hydro could file a proposed PBR plan, using fiscal 2021 as the base year, by February 2021. This timeline would provide

[503] Schmidt, page 105.

approximately one year, following the BCUC's decision on BC Hydro's Revenue Requirements Application, to develop a PBR plan and conduct consultation with customer groups and BCUC staff.

11.7.2 Proposed Consultation Approach

There are many significant and complex issues that will inform whether PBR is adopted for BC Hydro and how a PBR plan is designed. Given the nature and importance of these issues, we believe that extensive consultation with customer groups and BCUC staff would be required to identify concerns, opportunities and potential solutions.

A potential approach would be to adopt a consultation process similar to the one used to inform our 2015 Rate Design Application. BC Hydro could conduct topic-specific workshops, including information presentations and a question and answer session. The following topics may be appropriate for dedicated workshops:

- PBR Principles – to establish common objectives that all parties hope to achieve from the transition from cost of service regulation to PBR;
- PBR Framework – including whether BC Hydro's PBR plan should be a price cap or a revenue cap, if a hybrid approach is appropriate, the criteria for uncontrollable (Y) and unforeseen (Z) factors, potential key performance indicators to monitor progress and the appropriate Annual Review process;
- Creating and Sharing Benefits Under PBR – including the length of the PBR term and the appropriate application of efficiency carry-over mechanisms, stretch factors, an earnings sharing mechanisim and off-ramps and re-openers; and
- Managing Capital and Other Costs Under PBR – including how capital spending and other cost components should be managed under the PBR plan and the appropriate trade-offs between the incentives provided, the degree of

regulatory oversight and the level of certainty that funding will be sufficient to support the required investment.

In addition to the workshops, BC Hydro could use the following process to obtain and consider feedback. Based on previous experience, two to three months would be required to complete the full cycle for each workshop topic:

- Materials, including the presentation and any background or supporting information, would be circulated in advance of each workshop;
- Workshop summary notes, including stakeholder questions and BC Hydro initial responses, would be posted in draft to an external website for access by participants;
- Stakeholders would provide written comments for consideration by BC Hydro and all participants; and
- BC Hydro would prepare consideration memos for each workshop to summarize feedback received and how that feedback was considered and used to develop or narrow alternatives.

Some interveners have previously expressed reservations about the adoption of PBR in British Columbia and for BC Hydro.[504] In its Decision on FortisBC's 2014 to 2018 PBR Application, the BCUC stated:

> "Regardless of the method chosen, to be successful over the longer term, the parties need to feel that their concerns are heard and where reasonable, acted upon." [505]

BC Hydro believes that a negotiated settlement process to identify areas of common agreement prior to BC Hydro's submission of a proposed PBR plan may help to secure intervener and stakeholder support for elements of a proposed PBR plan.

[504] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 10-15 and BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects Workshop Transcript (May 23, 2018), pages 69 to 72.

[505] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan 2014-2018 (September 15, 2014), page 15.

Negotiated settlements have been successful in British Columbia in the past.[506] In addition, in their summary paper titled *Negotiated Settlements: The development of legal and economic thinking*, Dr. Joseph Doucet and Dr. Stephen Littlechild[507] identify a number of advantages to this approach.

For example, as explained in *Nonunanimous settlement of public utility rate cases: a response*, a negotiated settlement process may identify better solutions than a traditional regulatory process:

> "…the settlement process permits solutions that the regulatory agency itself, constrained by statute, may *not* be able to pursue… the flexibility inherent in the settlement process may be by far the most telling ground for its encouragement…"[508]

Further, as explained in *Democracy and Regulation: How the Public can Govern Essential Services*, a negotiated settlement may produce a more acceptable outcome:

> "[W]hen the regulator makes the decisions, everyone loses something, and the parties have no control over what they lose. In the negotiation process, each party chooses which among the many points it is willing to lose in order to gain something else. Although this may sound like a distinction without a difference, in fact, the trade-offs arrived at voluntarily are much more stable and effective. Negotiated settlements are actually more democratic because all parties participate in the decision. As a result the terms are more likely to be implemented with enthusiasm and effectiveness than if they had been imposed from above by a regulator. Furthermore, in an atmosphere of

[506] BCUC Decision, BC Hydro Fiscal 2011 Revenue Requirements Application, Appendix FF, Order No. G-180-1, pages 4 and 7 and BCUC Decision, FortisBC Energy Utilities 2012-2013 Revenue Requirements and Rates Application, pages 21 to 22.

[507] Dr. Littlechild is widely regarded as the pioneer of performance based regulation in the United Kingdom. In 1983, he authored a report to the Secretary of State for Industry entitled "Regulation of British Telecommunications' Profitability" which is often referred to as "The Littlechild Report."

[508] Buchmann, A.P., Tongren, R.S., 1996. Nonunanimous settlement of public utility rate cases: a response. Yale Journal of Regulation 13, page 343.

> trust and negotiation, more information is freely shared, with the result that more comprehensive solutions can be developed."[509]

Lastly, as Dr. Doucet and Dr. Littlechild observe, a negotiated settlement process may foster trust and collaboration:

> "Settlements have also provided a new forum of collaboration and increased value creation between pipelines and their customers. Observers and participants are in no doubt that this could not have occurred under the traditional litigated approach to utility regulation."[510]

11.8 BC Hydro Should Continue to be Regulated Through Cost of Service Regulation

In sections 11.3 to 11.7 above, BC Hydro has provided its initial conclusions in response to the issues raised by the BCUC. This provides a framework for a PBR plan, should the BCUC decide to adopt PBR for BC Hydro. However, for the following four reasons, we believe that BC Hydro should continue to be regulated through cost of service regulation at this time.

11.8.1 Cost of Service Regulation Should Be Given Time to Work

First, after years of significant limitations on the BCUC's jurisdiction over BC Hydro, cost of service regulation should now be given the opportunity to work.

As shown in Table 11-4 below, through various directions, the Government of B.C. has historically limited the BCUC's oversight of BC Hydro. Government directions have, for all practical purposes, determined rates in recent years.

509 Palast, G., Oppenheim, J., MacGregor, T., 2003. Democracy and Regulation: How the Public can Govern Essentla Services, page 96.

510 Doucet, Joseph and Littlechild, Stephen. Negotiated settlements: The development of legal and economic thinking. Utilities Policy 14 (2006), page 274.

Table 11-4 BC Hydro Revenue Requirement Proceedings and Government Directions

Revenue Requirement Proceeding	Government Direction	Outcome
Fiscal 2005 to Fiscal 2006		BCUC Decision (Order No. G-94-06)
Fiscal 2007 to Fiscal 2008		Negotiated Settlement Agreement (Order No. G-143-06)
Fiscal 2009 to Fiscal 2010		BCUC Decision (Order No. G-16-09)
Fiscal 2011		Negotiated Settlement Agreement (Order No. G-180-10)
Fiscal 2012 to Fiscal 2014	Direction 3	Rates set by Direction 3 (Order No. G-77-12A)
Fiscal 2015 to Fiscal 2016	Direction 6	Rates set by Direction 6 (Order No. G-48-14)
Fiscal 2017 to Fiscal 2019	Direction 7	BCUC Decision within rate caps set by Direction 7 (Order No. G-47-18)

It has been nine years since the BCUC made an unconstrained rate decision under cost of service regulation.[511]

The Fiscal 2017 to Fiscal 2019 Revenue Requirements Application provided the opportunity for a detailed examination of BC Hydro's operations and forecast costs. However, due to the rate caps and various other directives prescribed by Direction No. 7, the BCUC's oversight was more limited than it would have been in a traditional cost of service proceeding.

In its Decision on the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, the BCUC stated:

> "We acknowledge BC Hydro's cost cutting measures and also the upcoming comprehensive government review of BC Hydro's expenditures and we are hopeful that further efficiencies can be found. Our concern lies in the apparent decoupling of revenues and expenditures within the test period. Expenditures have risen

[511] BCUC Order No. G-180-10 authorizing the Fiscal 2011 Negotiated Settelement Agreement was issued on February 19, 2010. As part of the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application proceeding, an Oral Hearing was held from October 6, 2008 to October 29, 2008.

> faster than revenues. A company with expenditures that exceed its revenues is not sustainable. Accordingly we are of the view that a rate setting mechanism that could help BC Hydro to accomplish its cost control objectives is of value."[512]

In June 2018, the Government of B.C. initiated a Comprehensive Review of BC Hydro. Phase One of the Comprehensive Review resulted in two significant changes:

- First, the Government of B.C. rescinded Direction Nos. 3, 6, and 7, enhancing the BCUC's oversight of BC Hydro.
- Second, BC Hydro ceased using the Rate Smoothing Regulatory Account at the end of the third quarter of fiscal 2019. The Rate Smoothing Regulatory Account, in combination with the rate caps prescribed by Direction No. 7, had allowed BC Hydro to defer portions of the approved revenue requirement in a particular fiscal year for recovery in future fiscal years. In this application, BC Hydro is not proposing to smooth rates during the fiscal 2020 to fiscal 2021 test period and is requesting BCUC approval to close the Rate Smoothing Regulatory Account.

With enhanced oversight of BC Hydro and the closure of the Rate Smoothing Regulatory Account, the BCUC now has the ability to examine BC Hydro's forecast revenues and expenditures and to set rates based on cost of service principles. BC Hydro believes that unconstrained cost of service proceedings would address the issues raised by the BCUC in its Decision and that cost of service regulation should be given the opportunity to work, before the adoption of PBR is seriously considered.

[512] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 33.

11.8.2 Conferring the Necessary Autonomy on BC Hydro Under PBR May Be Less Palatable Given the Return to Enhanced Regulation is So Recent

Second, the fact that BC Hydro is only now returning to enhanced regulation is likely to make it more challenging to secure stakeholder support for the principles of PBR.

As Dr. Weisman explains in his report, there may be little practical difference between PBR and cost of service regulation, in the absence of a strong regulatory commitment to the principles of PBR. A key principle of PBR is that the utility should be provided with the autonomy to manage its expenditures within the PBR framework without a detailed regulatory review that would second guess the decisions made. In exchange for this increased autonomy, the utility assumes both the risk that the PBR formula may not sufficiently fund certain costs as well as the opportunity to retain additional savings, if new efficiencies are discovered, over and above what is required to meet the formula.

A strong regulatory commitment to this principle requires stakeholder support for the adoption of PBR over cost of service regulation. In the absence of stakeholder support, it may be difficult to avoid detailed regulatory reviews that would lead to second guessing.

BC Hydro believes that it may be challenging to secure stakeholder support for the adoption of PBR at this time:

- Intervener comments during a workshop in the BCUC's Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding indicate that many interveners may have concerns about the increased autonomy from detailed regulatory review that some of BC Hydro's cost components would receive under PBR.[513]

[513] BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects Workshop Transcript (May 23, 2018), pages 69 to 72.

- Greater autonomy from detailed regulatory review is likey the opposite of what interveners are expecting, following a prolonged period where the BCUC's oversight of BC Hydro has been limited.
- In its Decision, the BCUC stated that it did not have a high degree of comfort in BC Hydro's starting operating costs, given its limited involvement in the approval of recent revenue requirements.

If PBR is adopted for BC Hydro, the regulatory framework for BC Hydro would have shifted from cost of service regulation with rate caps, to cost of service regulation without rate caps, to PBR, in a very short period of time. BC Hydro believes that it would be difficult to secure stakeholder support and regulatory commitment to the principles of PBR, so soon after BC Hydro's return to enhanced regulation. In addition, cycling through various regulatory regimes, in such a short time frame, is likely to create instability and uncertainty that can undermine confidence in the regulatory process.

In addition, it would be particularly important to establish familiarity and comfort with BC Hydro's costs, prior to locking them in as base costs, for a prolonged period of time, under a PBR plan. BC Hydro believes that the most effective way to build a strong foundation of familiarity and comfort is through successive cost of service proceedings that would provide the BCUC and interveners with the opportunity to become fully conversant with BC Hydro's operations.

11.8.3 Cost of Service Regulation is Intuitive While PBR is Esoteric

Third, cost of service regulation is more transparent and accessible while PBR is more esoteric, relying on specialized expertise.

The process under cost of service regulation is fairly intuitive: BC Hydro provides information, the BCUC and interveners ask questions and the BCUC sets rates to recover only those costs that it determines to be prudently incurred plus a reasonable rate of return.

Under PBR, once base costs are established, the amount of revenue recovered through rates would be largely independent of BC Hydro's costs. This separation is achieved by adjusting rates for the effects of inflation and productivity improvements for a specified period of time. This shifts the focus of the proceeding from determining the prudent level of spending to identifying total factor productivity growth for the electricity industry, determining what costs can be accommodated by a formula or should be treated as flow through items, guarding against service deterioration, and determining how benefits and risks should be allocated.

These issues introduce an alphabet of factors (e.g., i, x, k, y, z) into the regulatory process. The design of PBR, the inter-relationship among various PBR elements, and determination of these factors is highly specialized and is primarily the domain of experts. The complexity of these issues makes PBR inherently less accessible to customers and the public generally. While interveners are eligible for Participant Assistance Cost Award funding, which can help fund experts and other support, participants and customers may feel more disconnected from these types of proceedings than a traditional cost of service review.

11.8.4 PBR is Premised on a Profit Incentive, but BC Hydro Does Not Have a Mandate to Maximize Profits

Fourth, BC Hydro does not have a mandate to maximize profits, which can dull the additional "carrot" incentive that PBR attempts to provide.

When the amount of revenue recovered through rates is de-linked from a utility's costs, rather than dependent on them, this creates both "carrot" and "stick" incentives for efficient performance.

In the conclusion to his report, Dr. Weisman discusses the adoption of PBR for Crown Corporations like BC Hydro, stating:

> "Policymakers should recognize that the expected gains from adopting PBR may be subject to greater uncertainty in the case of crown corporations. In many respects, these public enterprises are de facto subject to two different

> regulatory authorities—the regulatory commission of jurisdiction and its government owners." [514]

As a Crown Corporation, under cost of service regulation, BC Hydro already has significant "stick" incentives to operate efficiently:

- As BC Hydro's shareholder, the Government of B.C. has required BC Hydro to manage within a very efficient framework. For example, the 2013 10 Year Rates Plan set rate targets for fiscal 2020 to fiscal 2024 and BC Hydro was required to find new efficiencies to maintain those rate targets as a declining rate of load growth created new cost pressures. In addition, through the Comprehensive Review, the Government of B.C. and BC Hydro worked together to identify additional opportunities to reduce costs, to support the government's affordability mandate.
- As BC Hydro's revenue requirements applications are submitted on a forecast basis and cover multiple years, rates are set independently of BC Hydro's actual costs over the test period. This means that unexpected cost pressures that arise during the test period must be managed and fully absorbed by BC Hydro within its existing approved revenue requirement, unless there is a regulatory mechanism in place to defer the impact.

By allowing a utility or its shareholder to retain all or a portion of the savings over and above what is required to meet the formula, PBR aims to use financial incentives to motivate a process through which new savings - that were not previously identified under cost of service regulation - are discovered. This process is intended to emulate what would happen in a competitive market where, in an effort to increase their market share, rival producers would continually discover new ways to reduce their costs, achieving "dynamic" efficiencies.

Accordingly, the incremental benefit of adopting PBR would be to provide "carrot" incentives on top of the "stick" incentives that are already in place.

[514] Appendix FF, page 63

The challenge with applying this approach to BC Hydro is that it assumes BC Hydro is motivated by the prospect of higher earnings. This is not the case. Rather, the Government of B.C. expects BC Hydro to achieve its allowed net income target, not to exceed it. This does not mean that BC Hydro will not seek out or find additional efficiencies in future years. Rather, it means that the incentive to find these efficiencies would come, as it does today, from the obligation and commitment on the part of management to deliver on its mandate and not from the opportunity to increase earnings.

11.8.5 Cost of Service Regulation is More Appropriate for BC Hydro than PBR

In sections 11.3 to 11.7 above, BC Hydro has provided its initial conclusions in response to the issues raised by the BCUC. This provides a framework for a PBR plan, should the BCUC decide to adopt PBR for BC Hydro. However, for the reasons set out above, we believe that BC Hydro should continue to be regulated through cost of service regulation at this time. BC Hydro respectfully recommends that the BCUC use this Revenue Requirements Application proceeding to engage interveners to canvass their views.

List of Appendices

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Appendix A

Financial Schedules

Table of Contents

1 Overview

Appendix A contains the detailed financial schedules of the revenue requirements model, and is intended to provide, in a single location, the details of the elements which make up the revenue requirements for the Test Period and prior years. The working revenue requirements model that produces the schedules is provided in electronic form as part of this filing.

The overall purpose, general structure and model mechanics of Appendix A remains unchanged from the Previous Application. Appendix A is provided in this Application in two forms: the printed form and the electronic form. The printed form includes information for the fiscal 2020 and fiscal 2021 Test Period, as well as the Previous Application information from fiscal 2017 to fiscal 2019. The electronic form of Appendix A includes information for the fiscal 2020 and fiscal 2021 Test Period, as well as historical RRA and Actual or Forecast information over the five year period from fiscal 2015 to fiscal 2019.

Of the 42 total schedules in Appendix A, 23 are used for the purpose of providing information on BC Hydro's total revenue requirements, while 19 are used for the purpose of determining the Transmission Revenue Requirement. The Table of Contents in Appendix A includes a column indicating the primary purpose of each schedule in Appendix A.

Where possible, BC Hydro has made a number of modifications to Appendix A to simplify schedules. In addition, BC Hydro has added new schedules to enable the allocation of operating costs to Transmission, Distribution, Generation and Customer Care functions in order to determine the Transmission Revenue Requirement (which is presented in Chapter 9). These changes, and others, are described below.

2 Simplification - Elimination of Rows

In all schedules throughout Appendix A, rows which relate to items from applications prior to fiscal 2015 and which are no longer required, have been removed.

3 New Schedules - Cost Allocation

BC Hydro's re-organization results in a centralized organizational structure which aligns with the work functions that we perform – planning, building, operating and supporting. As part of preparing the Transmission Revenue Requirement, and in order to continue the methodology of allocating operating costs to the Generation, Transmission, Distribution, and Customer Care functions, BC Hydro has added eight new schedules, Schedules 3.6 to 3.13, for the purposes of allocating Operating Costs and Provisions to these functions.

The Current Operating Costs and Provisions for each Business Group are shown on Schedules 3.7 to 3.13, and are allocated within these schedules to the Generation, Transmission, Distribution, Customer Care, and Business Support functions. Schedule 3.6 summarizes these allocations. The allocation of historical Current Operating Costs and Provisions under the current Business Groups has been included in these schedules for presentation purposes only. RRA and Actual allocations from previous approved Revenue Requirement Applications are still used in calculating the final allocations in fiscal 2015 to fiscal 2019.

No additional schedules were required for other components of BC Hydro's revenue requirements (i.e., Cost of Energy, Amortization, Finance Charges, Taxes etc.) as the allocation of costs to specific functions have not been impacted by changes in BC Hydro's organization structure.

4 Categorization of Cost of Energy

As discussed in Chapter 4, section 4.2, the repeal of the Heritage Contract means that BC Hydro now has the flexibility to categorize its costs of energy differently in Appendix A. In Schedule 4.0, which sets out BC Hydro's costs of energy, BC Hydro has created a new category called Market Energy and categorized its energy costs into Heritage Energy, Non-Heritage Energy and Market Energy. We believe that this categorization will make it easier to understand BC Hydro's energy costs.

5 Presentation of Waneta 2017 Revenues

Pursuant to Order No. G-130-18, the revenue from the Waneta 2017 transaction must be shown as a line item separate from revenue from rate regulated activities in BC Hydro's revenue requirement applications. BC Hydro has shown revenue related to the Waneta 2017 transaction in lines 20 to 23, 33 and 34 on Schedule 15.0.

6 Revised Schedules - Operating Costs

Schedules 5.1 to 5.7 present BC Hydro's operating costs by Business Group. These schedules replace Schedules 5.1 to 5.5 from the Appendix A in the Previous Application, which showed operating costs according to the previous Business Groups. Operating costs, both RRA and Actual, from fiscal 2015 to fiscal 2019 have been restated according to the new Business Groups.

Additionally, to address BCUC's concern relating to the various terminologies used to describe BC Hydro's operating costs, a table has been provided at the bottom of Schedule 5.0 in Appendix A to illustrate the continuity of the various operating cost views. These operating cost views are further explained in Chapter 5, section 5.5.1.

Revenue Requirements Model

Note 1: RRA (Revenue Requirement Application); TRR (Transmission Revenue Requirement)

Revenue Requirements Summary
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
1	**Cost of Energy**	3.0 L1	1,549.3	1,505.5	(43.8)	1,657.8	1,538.7	(119.2)	1,762.9	1,673.4	(89.5)	1,887.0	1,920.2
2	**Operating Costs**	3.0 L13	1,185.0	1,165.1	(19.9)	1,220.0	1,228.7	8.7	1,221.0	1,257.5	36.5	1,224.2	1,229.3
3	**Taxes**	3.0 L22	223.3	223.1	(0.2)	231.8	231.1	(0.8)	238.7	242.2	3.5	249.8	262.2
4	**Amortization**	3.0 L25	783.2	777.9	(5.3)	821.1	807.6	(13.4)	850.9	871.5	20.6	915.7	936.5
5	**Finance Charges**	3.0 L31	708.8	579.2	(129.6)	735.0	805.9	71.0	773.8	684.6	(89.2)	757.5	726.9
6	**Return on Equity**	3.0 L38	684.0	683.5	(0.5)	698.0	684.0	(14.0)	712.0	(424.3)	(1,136.3)	712.0	712.0
7	**Miscellaneous Revenue**	3.0 L42	(137.1)	(143.1)	(6.0)	(138.3)	(143.7)	(5.5)	(140.6)	(202.9)	(62.3)	(240.8)	(247.2)
8	**Inter-Segment Revenue**	3.0 L51	(62.5)	(56.9)	5.5	(64.3)	(66.4)	(2.1)	(65.3)	(64.3)	1.0	(69.0)	(72.6)
	Deferral Accounts												
9	Deferral Account Additions	2.1 L24	0.0	63.3	63.3	0.0	203.7	203.7	0.0	222.8	222.8	3.1	3.5
10	Interest on Deferral Accounts	2.1 L25	(41.5)	(41.1)	0.4	(34.3)	(26.5)	7.8	(26.6)	(3.8)	22.8	8.9	3.0
11	Deferral Account Recoveries	2.1 L26	223.5	223.7	0.2	231.3	233.2	1.9	241.8	241.2	(0.7)	(164.5)	(164.5)
12	Total		182.0	245.8	63.9	197.0	410.4	213.4	215.3	460.2	244.9	(152.5)	(158.1)
	Other Regulatory Accounts												
13	Regulatory Account Additions	2.2 L204	(259.7)	(46.8)	212.9	(217.1)	(237.7)	(20.6)	(201.6)	(184.0)	17.6	(168.2)	(162.3)
14	Interest on Regulatory Accounts	2.2 L205	(34.3)	(34.2)	0.0	(34.1)	(35.2)	(1.1)	(33.5)	(34.8)	(1.3)	(33.2)	(30.5)
15	Regulatory Account Recoveries	2.2 L206	8.0	(57.0)	(65.1)	(107.0)	(188.4)	(81.3)	(111.6)	1,023.0	1,134.6	326.7	324.7
16	Total		(285.9)	(138.0)	147.9	(358.1)	(461.2)	(103.1)	(346.8)	804.2	1,150.9	125.3	131.9
	Subsidiary Net Income												
17	Powerex Net Income		(115.2)	(130.2)	(15.1)	(115.2)	(136.6)	(21.4)	(115.1)	(205.3)	(90.2)	(120.6)	(120.6)
18	Powertech Net Income		(4.5)	(2.1)	2.4	(4.8)	(3.1)	1.7	(5.1)	(3.3)	1.8	(3.4)	(3.7)
19	Total		(119.7)	(132.4)	(12.7)	(119.9)	(139.6)	(19.7)	(120.2)	(208.6)	(88.4)	(124.0)	(124.3)
20	**Less Other Utilities Revenue**	14.0 L18	(12.6)	(13.0)	(0.5)	(12.0)	(11.9)	0.1	(12.1)	(28.6)	(16.5)	(28.6)	(28.7)
21	**Less Liquefied Natural Gas Revenue**	14.0 L19	(4.4)	(0.4)	4.0	(10.7)	(1.3)	9.4	(10.9)	(0.3)	10.6	0.0	0.0
22	**Less Deferral Rider**	14.0 L21	(223.5)	(223.7)	(0.2)	(231.3)	(233.2)	(1.9)	(241.8)	(241.2)	0.7	0.0	0.0
23	**Total Rate Revenue Requirement**		4,469.9	4,472.6	2.7	4,626.1	4,649.1	23.0	4,836.8	4,823.4	(13.4)	5,256.5	5,288.3
	Rate Revenue at Current Rates												
24	Total Domestic Revenue	14.0 L22	4,710.3	4,709.7	(0.6)	4,880.2	4,895.5	15.3	5,101.6	5,093.4	(8.2)	4,948.2	4,942.4
25	Less Other Utilities	Line 20	(12.6)	(13.0)	(0.5)	(12.0)	(11.9)	0.1	(12.1)	(28.6)	(16.5)	(28.6)	(28.7)
26	Less Liquefied Natural Gas Revenue	Line 21	(4.4)	(0.4)	4.0	(10.7)	(1.3)	9.4	(10.9)	(0.3)	10.6	0.0	0.0
27	Less Deferral Rider	Line 22	(223.5)	(223.7)	(0.2)	(231.3)	(233.2)	(1.9)	(241.8)	(241.2)	0.7	0.0	0.0
28	Revenue Subject to Rate Increase		4,469.9	4,472.6	2.7	4,626.1	4,649.1	23.0	4,836.8	4,823.4	(13.4)	4,919.6	4,913.7
29	**Revenue Shortfall**	L23 - L28	0.0	0.0		(0.0)	0.0		0.0	0.0		336.9	374.5
30	**Rate Increases**		4.00%	4.00%		3.50%	3.50%		3.00%	3.00%		6.85%	0.72%
31	**Deferral Account Rate Rider**		5.00%	5.00%		5.00%	5.00%		5.00%	5.00%		-	-
32	**Net Bill Impact**		4.00%	4.00%		3.50%	3.50%		3.00%	3.00%		1.76%	0.72%
33	**Total Rate Revenue Requirement**	Line 23	4,469.9	4,472.6	2.7	4,626.1	4,649.1	23.0	4,836.8	4,823.4	(13.4)	5,256.5	5,288.3
34	**Rate Smoothing Regulatory Account transfers**	2.2 L136	216.5	201.2	(15.2)	311.0	326.2	15.2	321.4	(814.9)	(1,136.3)	0.0	0.0
35	**Revenue Requirement before transfers to Rate Smoothing Regulatory Account**		4,686.4	4,673.8	(12.5)	4,937.1	4,975.3	38.2	5,158.2	4,008.5	(1,149.7)	5,256.5	5,288.3

Deferral Accounts
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Heritage Deferral Account												
1	Beginning of Year		(23.9)	(23.9)	0.0	(20.1)	(53.1)	(33.0)	(16.0)	(103.7)	(87.7)	(388.3)	(197.9)
2	Adjustment to Opening Balance		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	(318.9)	(318.9)	0.0	0.0
3	Additions	Line 30	0.0	(31.0)	(31.0)	0.0	(60.4)	(60.4)	0.0	(7.5)	(7.5)	0.0	0.0
4	Interest		(0.9)	(2.8)	(1.9)	(0.7)	(4.0)	(3.3)	(0.6)	(9.6)	(9.1)	(11.1)	(3.7)
5	Recovery		4.7	4.7	0.0	4.8	13.8	9.0	5.1	51.4	46.3	201.6	201.6
6	End of Year		(20.1)	(53.1)	(33.0)	(16.0)	(103.7)	(87.7)	(11.5)	(388.3)	(376.8)	(197.9)	0.0
	Non-Heritage Deferral Account												
7	Beginning of Year		916.8	916.8	0.0	770.9	755.8	(15.0)	612.8	463.3	(149.5)	119.9	52.1
8	Adjustment to Opening Balance		0.0	(0.1)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	(18.0)	0.0
9	Additions	Line 31	0.0	(17.2)	(17.2)	0.0	(122.0)	(122.0)	0.0	(73.9)	(73.9)	0.0	0.0
10	Additions - Waneta 2/3	15.0 L38								(51.3)	(51.3)	(3.1)	(3.5)
11	Interest		33.3	35.7	2.4	27.5	26.0	(1.5)	21.3	11.4	(9.9)	2.9	1.0
12	Recovery		(179.3)	(179.4)	(0.1)	(185.5)	(196.5)	(10.9)	(194.0)	(229.7)	(35.7)	(49.6)	(49.6)
13	End of Year		770.9	755.8	(15.0)	612.8	463.3	(149.5)	440.1	119.9	(320.2)	52.1	(0.0)
	Trade Income Deferral Account												
14	Beginning of Year		250.0	250.0	0.0	210.2	194.2	(16.0)	167.1	126.8	(40.3)	(24.2)	(12.3)
15	Adjustment to Opening Balance		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Additions	Line 32	0.0	(15.1)	(15.1)	0.0	(21.4)	(21.4)	0.0	(90.2)	(90.2)	0.0	0.0
17	Interest		9.1	8.2	(0.9)	7.5	4.5	(3.0)	5.8	2.0	(3.8)	(0.7)	(0.2)
18	Recovery		(48.9)	(48.9)	(0.0)	(50.6)	(50.5)	0.1	(52.9)	(62.9)	(10.0)	12.6	12.6
19	End of Year		210.2	194.2	(16.0)	167.1	126.8	(40.3)	120.0	(24.2)	(144.2)	(12.3)	(0.0)
	End of Year Balances												
20	Heritage	Line 6	(20.1)	(53.1)	(33.0)	(16.0)	(103.7)	(87.7)	(11.5)	(388.3)	(376.8)	(197.9)	0.0
21	Non-Heritage	Line 13	770.9	755.8	(15.0)	612.8	463.3	(149.5)	440.1	119.9	(320.2)	52.1	(0.0)
22	Trade Income	Line 19	210.2	194.2	(16.0)	167.1	126.8	(40.3)	120.0	(24.2)	(144.2)	(12.3)	(0.0)
23	Total		961.0	896.9	(64.0)	763.9	486.5	(277.4)	548.6	(292.6)	(841.3)	(158.1)	(0.0)
	Summary												
24	Deferral Account Additions		0.0	(63.3)	(63.3)	0.0	(203.7)	(203.7)	0.0	(222.8)	(222.8)	(3.1)	(3.5)
25	Interest on Deferral Accounts		41.5	41.1	(0.4)	34.3	26.5	(7.8)	26.6	3.8	(22.8)	(8.9)	(3.0)
26	Deferral Account Recoveries		(223.5)	(223.7)	(0.2)	(231.3)	(233.2)	(1.9)	(241.8)	(241.2)	0.7	164.5	164.5
27	Adjustment to Opening Balance	L2+L8+L15	0.0	(0.2)	(0.2)	0.0	0.0	0.0	0.0	(318.9)	(318.9)	(18.0)	0.0
28	Deferral Account Net Transfers		(182.0)	(246.0)	(64.0)	(197.0)	(410.4)	(213.4)	(215.3)	(779.1)	(563.9)	134.5	158.1
29	**Interest Rate**	8.0 L52	4.03%	3.97%	(0.06%)	4.05%	3.96%	(0.09%)	4.13%	3.98%	(0.15%)	3.88%	3.82%
	Summary of Items Subject to Deferral												
30	Cost of Heritage Energy	4.0 L66	305.3	274.3	(31.0)	285.4	225.1	(60.4)	317.1	309.6	(7.5)	327.7	294.2
31	Cost of Non-Heritage Energy	4.0 L80	1,271.9	1,254.7	(17.2)	1,409.3	1,287.3	(122.0)	1,482.9	1,409.0	(73.9)	1,571.0	1,637.2
32	Trade Income	1.0 L17	(115.2)	(130.2)	(15.1)	(115.2)	(136.6)	(21.4)	(115.1)	(205.3)	(90.2)	(120.6)	(120.6)

Other Regulatory Accounts
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
		Column	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Demand-Side Management												
1	Beginning of Year		907.2	907.2	0.0	931.8	915.6	(16.3)	954.6	902.5	(52.1)	927.1	932.0
2	Adjustment to Opening Balance		0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Additions	5.0 L53	113.7	97.4	(16.3)	119.5	82.5	(36.9)	127.9	124.2	(3.7)	109.1	125.9
4	Amortization on Existing		(89.1)	(89.1)	(0.0)	(96.7)	(95.6)	1.1	(102.8)	(99.6)	3.2	(104.2)	(108.3)
5	Amortization on Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	End of Year		931.8	915.6	(16.3)	954.6	902.5	(52.1)	979.7	927.1	(52.6)	932.0	949.7
	First Nations Costs												
7	Beginning of Year		132.8	132.8	0.0	131.1	123.6	(7.5)	120.3	104.3	(16.0)	85.1	71.5
8	Adjustment to Opening Balance		0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Additions	5.0 L54	5.6	4.0	(1.6)	3.7	2.0	(1.7)	2.8	3.4	0.7	3.2	2.4
10	Transfer from Provision	Line 18	21.3	13.8	(7.5)	20.8	12.6	(8.2)	12.4	14.1	1.6	15.0	13.1
11	Interest		5.2	5.4	0.2	5.0	4.8	(0.2)	4.5	3.7	(0.8)	3.0	2.4
12	Recovery	5.0 L25	(33.8)	(32.4)	1.3	(40.2)	(38.7)	1.5	(39.0)	(40.4)	(1.4)	(34.7)	(33.6)
13	End of Year		131.1	123.6	(7.5)	120.3	104.3	(16.0)	101.0	85.1	(15.9)	71.5	55.8
	First Nations Settlement Provisions												
14	Beginning of Year		408.6	408.6	0.0	399.2	408.6	9.4	395.7	414.2	18.5	420.0	422.6
15	Adjustment to Opening Balance		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Additions - Operating	5.0 L103	(5.3)	(3.3)	2.0	0.0	0.9	0.9	0.0	2.4	2.4	0.0	0.0
17	Additions - Accretion	8.0 L4	17.2	17.2	0.0	17.2	17.2	(0.0)	17.4	17.5	0.0	17.6	18.0
18	Transfer to Negotiation Costs		(21.3)	(13.8)	7.5	(20.8)	(12.6)	8.2	(12.4)	(14.1)	(1.6)	(15.0)	(13.1)
19	End of Year		399.2	408.6	9.4	395.7	414.2	18.5	400.7	420.0	19.3	422.6	427.5
	Site C Project												
20	Beginning of Year		435.6	435.6	0.0	453.1	453.3	0.1	471.5	472.0	0.5	491.2	508.5
21	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Additions	5.0 L55+8.0 L22	0.0	0.0	0.0	0.0	0.3	0.3	0.0	0.3	0.3	(1.7)	(2.4)
23	Interest		17.5	17.7	0.1	18.4	18.4	0.0	19.5	18.8	(0.7)	19.0	19.4
24	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	End of Year		453.1	453.3	0.1	471.5	472.0	0.5	491.0	491.2	0.2	508.5	525.5
	Future Removal and Site Restoration												
26	Beginning of Year		(8.6)	(8.6)	0.0	0.0	2.9	2.9	0.0	(0.0)	(0.0)	0.0	0.0
27	Adjustment to Opening Balance		0.0	(0.0)	(0.0)	0.0	(2.9)	(2.9)	0.0	0.0	0.0	0.0	0.0
28	Additions	5.0 L108	0.0	2.9	2.9			0.0			0.0		
29	Recovery	7.0 L27	8.6	8.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	End of Year		0.0	2.9	2.9	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0
	Foreign Exchange Gains/Losses												
31	Beginning of Year		(68.6)	(68.6)	0.0	(63.3)	(65.5)	(2.2)	(32.0)	(31.3)	0.6	7.2	4.9
32	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	Additions	8.0 L2	5.8	3.4	(2.4)	(6.8)	(4.2)	2.6	(3.5)	(0.0)	3.5	(2.1)	(0.8)
34	Recovery	8.0 L26	(0.6)	(0.4)	0.2	38.1	38.3	0.2	38.6	38.6	(0.0)	(0.2)	0.8
35	End of Year		(63.3)	(65.5)	(2.2)	(32.0)	(31.3)	0.6	3.1	7.2	4.1	4.9	5.0

Other Regulatory Accounts
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Pre-1996 Customer Contributions												
36	Beginning of Year		92.1	92.1	0.0	91.4	91.4	(0.0)	88.2	88.2	(0.0)	83.3	78.2
37	Adjustment to Opening Balance		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	Recovery	7.0 L28	(0.7)	(0.7)	0.0	(3.2)	(3.2)	0.0	(4.9)	(4.9)	0.0	(5.1)	(5.1)
39	End of Year		91.4	91.4	(0.0)	88.2	88.2	(0.0)	83.3	83.3	(0.0)	78.2	73.1
	Storm Restoration Costs												
40	Beginning of Year		29.5	29.5	0.0	19.7	38.6	19.0	9.8	46.5	36.6	38.1	19.0
41	Adjustment to Opening Balance		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	Additions	5.0 L56	0.0	18.6	18.6	0.0	16.2	16.2	0.0	0.0	0.0	0.0	0.0
43	Interest		1.0	1.3	0.4	0.6	2.1	1.5	0.2	1.7	1.5	1.1	0.4
44	Recovery	5.0 L26	(10.8)	(10.8)	(0.0)	(10.4)	(10.4)	0.0	(10.0)	(10.0)	0.0	(20.1)	(19.4)
45	End of Year		19.7	38.6	19.0	9.8	46.5	36.6	(0.0)	38.1	38.1	19.0	0.0
	Capital Project Investigation												
46	Beginning of Year		25.0	25.0	0.0	20.1	20.1	(0.0)	15.3	15.3	(0.0)	10.5	5.2
47	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0
48	Recovery	5.0 L27	(4.8)	(4.8)	(0.0)	(4.8)	(4.8)	(0.0)	(4.8)	(4.8)	0.0	(5.2)	(5.2)
49	End of Year		20.1	20.1	(0.0)	15.3	15.3	(0.0)	10.5	10.5	(0.0)	5.2	0.0
	F2010 ROE Adjustment												
50	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51	Recovery	9.0 L33	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
52	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Amortization of Capital Additions												
53	Beginning of Year		(9.7)	(9.7)	0.0	(6.4)	(8.8)	(2.4)	(3.2)	(5.2)	(2.0)	20.2	10.1
54	Adjustment to Opening Balance		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0
55	Additions	7.0 L18	0.0	(2.0)	(2.0)	0.0	0.7	0.7	0.0	21.8	21.8	0.0	0.0
56	Interest		(0.3)	(0.6)	(0.3)	(0.2)	(0.5)	(0.3)	(0.1)	0.3	0.4	0.6	0.2
57	Recovery	7.0 L30	3.6	3.6	0.0	3.4	3.4	0.0	3.3	3.3	0.0	(10.7)	(10.3)
58	End of Year		(6.4)	(8.8)	(2.4)	(3.2)	(5.2)	(2.0)	0.0	20.2	20.2	10.1	0.0
	Total Finance Charges												
59	Beginning of Year		(305.5)	(305.5)	0.0	(203.7)	(215.5)	(11.8)	(101.8)	(139.4)	(37.6)	(8.8)	(4.4)
60	Adjustment to Opening Balance		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0
61	Additions	8.0 L21	0.0	(12.6)	(12.6)	0.0	(25.1)	(25.1)	0.0	28.8	28.8	0.0	0.0
62	Recovery	8.0 L28:30	101.8	102.6	0.8	101.8	101.1	(0.8)	101.8	101.8	0.0	4.4	4.4
63	End of Year		(203.7)	(215.5)	(11.8)	(101.8)	(139.4)	(37.6)	0.0	(8.8)	(8.8)	(4.4)	0.0
	Smart Metering & Infrastructure												
64	Beginning of Year		282.6	282.6	0.0	260.8	260.9	0.1	239.1	239.2	0.1	217.1	195.4
65	Adjustment to Opening Balance		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66	Additions - Deferred Operating	5.0 L57	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
67	Additions - DSMD Write-Off	5.0 L106	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0
68	Additions - Miscellaneous Revenue	15.0 L41	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
69	Interest		10.7	11.0	0.3	9.9	10.1	0.2	9.2	8.9	(0.3)	7.8	6.9
70	Recovery	5.0 L28	(32.5)	(32.6)	(0.1)	(31.7)	(31.8)	(0.1)	(31.0)	(31.0)	0.0	(29.6)	(28.6)
71	End of Year		260.8	260.9	0.1	239.1	239.2	0.1	217.3	217.1	(0.2)	195.4	173.7

Other Regulatory Accounts
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Home Purchase Option Plan												
72	Beginning of Year		0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0
73	Adjustment to Opening Balance		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
74	Interest		0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0
75	Recovery	5.0 L29	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
76	End of Year		0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0
	Non-Current Pension Cost												
77	Beginning of Year		690.5	690.5	0.0	615.4	510.7	(104.7)	557.6	303.4	(254.2)	(3.0)	(18.9)
78	Adjustment to Opening Balance		(17.2)	0.0	17.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
79	OCI Deferral	9.0 L7	0.0	(203.2)	(203.2)	0.0	(193.6)	(193.6)	0.0	(248.5)	(248.5)	0.0	0.0
80	Additions	5.0 L59	0.0	10.1	10.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
81	Recovery - Operating	5.0 L31	(57.9)	(59.3)	(1.4)	(57.9)	(57.9)	(0.0)	(57.9)	(57.9)	0.0	(16.0)	(16.0)
82	Recovery - Finance Charges	8.0 L27	0.0	72.6	72.6	0.0	70.0	70.0	0.0	0.0	0.0	0.0	0.0
83	Transfer to PEB Current Pension-Addition		0.0	0.0	0.0	0.0	(27.3)	(27.3)	0.0	0.0	0.0	0.0	0.0
84	Transfer to PEB Current Pension-Recovery		0.0	0.0	0.0	0.0	1.4	1.4	0.0	0.0	0.0	0.0	0.0
85	End of Year		615.4	510.7	(104.7)	557.6	303.4	(254.2)	499.7	(3.0)	(502.7)	(18.9)	(34.9)
	Waneta												
86	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
87	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
88	End of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Environmental Provisions												
89	Beginning of Year		380.9	380.9	0.0	337.8	333.2	(4.6)	301.5	309.6	8.0	276.0	233.7
90	Adjustment to Opening Balance		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
91	Additions - Deferred Operating	5.0 L104	0.0	(28.0)	(28.0)	0.0	(4.0)	(4.0)	0.0	(4.3)	(4.3)	0.0	0.0
92	Additions - Accretion	8.0 L5	3.9	3.9	0.0	3.8	4.4	0.6	3.7	6.0	2.3	5.5	4.8
93	Transfer to Rock Bay		(6.2)	(1.6)	4.6	(6.4)	(0.7)	5.7	(9.3)	(0.3)	9.0	0.0	0.0
94	Transfer to Remediation (Asbestos)		(22.6)	(7.9)	14.6	(14.8)	(9.0)	5.8	(13.6)	(14.0)	(0.4)	(21.7)	(18.8)
95	Transfer to Remediation (PCB)	5.0 L78:L80	(18.3)	(14.2)	4.2	(18.9)	(14.3)	4.5	(15.3)	(20.9)	(5.6)	(26.1)	(26.0)
96	Recovery	5.0 L78:L80			0.0			0.0			0.0		
97	End of Year		337.8	333.2	(4.6)	301.5	309.6	8.0	267.0	276.0	9.0	233.7	193.7
	Rock Bay Remediation												
98	Beginning of Year		(27.2)	(27.2)	0.0	(18.1)	(23.0)	(4.8)	(9.1)	(20.0)	(10.9)	(20.5)	(10.3)
99	Adjustment to Opening Balance		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
100	Transfer from Environmental	Line 93	6.2	1.6	(4.6)	6.4	0.7	(5.7)	9.3	0.3	(9.0)	0.0	0.0
101	Interest		(0.9)	(1.0)	(0.1)	(0.5)	(0.9)	(0.3)	(0.2)	(0.8)	(0.6)	(0.6)	(0.2)
102	Recovery	5.0 L87	3.8	3.8	(0.0)	3.2	3.2	(0.0)	(0.0)	(0.0)	0.0	10.8	10.4
103	End of Year		(18.1)	(23.0)	(4.8)	(9.1)	(20.0)	(10.9)	0.0	(20.5)	(20.5)	(10.3)	(0.0)
	IFRS PP&E												
104	Beginning of Year		873.0	873.0	0.0	961.8	961.8	(0.0)	1,025.4	1,025.4	(0.0)	1,064.4	1,079.2
105	Adjustment to Opening Balance		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
106	Additions - Deferred Operating	5.0 L58	112.0	112.0	0.0	89.6	89.6	0.0	67.2	67.2	0.0	44.8	22.4
107	Recovery	5.0 L34	(23.2)	(23.2)	0.0	(26.0)	(26.0)	0.0	(28.2)	(28.2)	0.0	(29.9)	(31.0)
108	End of Year		961.8	961.8	(0.0)	1,025.4	1,025.4	(0.0)	1,064.4	1,064.4	(0.0)	1,079.2	1,070.6

Other Regulatory Accounts
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	IFRS Pension												
109	Beginning of Year		611.9	611.9	0.0	573.6	573.6	(0.0)	535.4	535.4	(0.0)	497.1	458.9
110	Adjustment to Opening Balance		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
111	Recovery	5.0 L35	(38.2)	(38.2)	0.0	(38.2)	(38.2)	0.0	(38.2)	(38.2)	0.0	(38.2)	(38.2)
112	End of Year		573.6	573.6	(0.0)	535.4	535.4	(0.0)	497.1	497.1	(0.0)	458.9	420.6
	Arrow Water Divestiture Costs												
113	Beginning of Year		0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0
114	Adjustment to Opening Balance		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
115	Transfer from Provision	Line 123	1.8	0.3	(1.5)	0.3	1.8	1.5	0.3	0.3	(0.0)	0.3	0.3
116	Interest		0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0
117	Recovery	5.0 L88:L89	(1.8)	(0.3)	1.5	(0.3)	(1.8)	(1.5)	(0.3)	(0.3)	0.0	(0.3)	(0.3)
118	End of Year		0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0
	Arrow Water Provision												
119	Beginning of Year		4.6	4.6	0.0	3.0	4.5	1.5	2.8	2.9	0.0	2.7	2.6
120	Adjustment to Opening Balance		0.0	(0.1)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
121	Additions	5.0 L105	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
122	Additions - Accretion	8.0 L6	0.2	0.2	0.0	0.2	0.2	0.0	0.2	0.2	0.0	0.2	0.1
123	Transfer to Arrow Water Costs	5.0 L89	(1.8)	(0.3)	1.5	(0.3)	(1.8)	(1.5)	(0.3)	(0.3)	0.0	(0.3)	(0.3)
124	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
125	End of Year		3.0	4.5	1.5	2.8	2.9	0.0	2.7	2.7	0.0	2.6	2.4
	Remediation												
126	Beginning of Year		5.1	5.1	0.0	3.4	(15.8)	(19.2)	1.7	(28.6)	(30.3)	(25.3)	(12.7)
127	Adjustment to Opening Balance		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
128	Transfer from Env. Prov. (Asbestos)	Line 94	22.6	7.9	(14.6)	14.8	9.0	(5.8)	13.6	14.0	0.4	21.7	18.8
129	Transfer from Env. Prov. (PCB)	Line 95	18.3	14.2	(4.2)	18.9	14.3	(4.5)	15.3	20.9	5.6	26.1	26.0
130	Interest		0.2	(0.2)	(0.4)	0.1	(0.7)	(0.8)	0.0	(1.1)	(1.1)	(0.7)	(0.2)
131	Recovery	5.0 L78:L83	(42.7)	(42.7)	0.0	(35.4)	(35.4)	0.0	(30.6)	(30.6)	0.0	(34.5)	(31.9)
132	End of Year		3.4	(15.8)	(19.2)	1.7	(28.6)	(30.3)	0.0	(25.3)	(25.3)	(12.7)	0.0
	Rate Smoothing												
133	Beginning of Year		287.4	287.4	0.0	503.9	488.7	(15.2)	814.9	814.9	(0.0)	(0.0)	(0.0)
134	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
135	Additions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
136	Recovery	5.0 L90	216.5	201.2	(15.2)	311.0	326.2	15.2	321.4	(814.9)	(1,136.3)	0.0	0.0
137	End of Year		503.9	488.7	(15.2)	814.9	814.9	(0.0)	1,136.3	(0.0)	(1,136.3)	(0.0)	(0.0)
	Real Property Sales												
138	Beginning of Year		17.7	17.7	0.0	25.1	28.2	3.2	15.9	37.7	21.9	44.1	37.6
139	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
140	Additions	5.0 L61+L107	6.5	9.8	3.3	(10.0)	8.4	18.4	(14.0)	4.8	18.8	(8.1)	(8.1)
141	Interest		0.8	0.7	(0.1)	0.8	1.1	0.3	0.4	1.6	1.2	1.6	1.3
142	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143	End of Year		25.1	28.2	3.2	15.9	37.7	21.9	2.2	44.1	41.9	37.6	30.8

Other Regulatory Accounts
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Minimum Reconnection Charge												
144	Beginning of Year		0.5	0.5	0.0	(0.0)	0.0	0.0	(0.0)	(0.0)	0.0	0.0	0.0
145	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
146	Additions	15.0 L42	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
147	Interest		0.0	0.0	0.0	(0.0)	(0.0)	0.0	(0.0)	0.0	0.0	0.0	0.0
148	Recovery		(0.5)	(0.9)	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
149	End of Year		(0.0)	0.0	0.0	(0.0)	(0.0)	0.0	(0.0)	0.0	0.0	0.0	0.0
	Debt Management												
150	Beginning of Year		0.0	0.0	0.0	0.0	(187.1)	(187.1)	0.0	(157.8)	(157.8)	(260.2)	(247.8)
151	Adjustment to Opening Balance		0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0
152	Additions	8.0 L7	0.0	(187.1)	(187.1)	0.0	29.3	29.3	0.0	(102.4)	(102.4)	0.0	0.0
153	Recovery	8.0 L29	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.4	12.4
154	End of Year		0.0	(187.1)	(187.1)	0.0	(157.8)	(157.8)	0.0	(260.2)	(260.2)	(247.8)	(235.5)
	Dismantling Cost												
155	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.4	35.4	50.9	25.5
156	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	2.9	2.9	0.0	(0.0)	(0.0)	0.0	0.0
157	Additions	5.0 L108			0.0	0.0	31.7	31.7	0.0	13.9	13.9	0.0	0.0
158	Interest		0.0	0.0	0.0	0.0	0.7	0.7	0.0	1.7	1.7	1.5	0.5
159	Recovery	5.0 L84:L86	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(26.9)	(25.9)
160	End of Year		0.0	0.0	0.0	0.0	35.4	35.4	0.0	50.9	50.9	25.5	0.0
	PEB Current Pension Costs												
161	Beginning of Year		0.0	0.0	0.0	11.5	0.0	(11.5)	5.7	3.3	(2.5)	(2.5)	(1.2)
162	Adjustment to Opening Balance		17.2	0.0	(17.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
163	OCI Deferral		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
164	Additions	5.0 L59+L60	0.0	0.0	0.0	0.0	(12.5)	(12.5)	0.0	0.0	0.0	0.0	0.0
165	Recovery - Operating	5.0 L32+L33	(5.7)	0.0	5.7	(5.7)	(10.0)	(4.3)	(5.7)	(5.7)	0.0	1.2	1.2
166	Transfer from NC Current Pension-Addition	Line 83	0.0	0.0	0.0	0.0	27.3	27.3	0.0	0.0	0.0	0.0	0.0
167	Transfer from NC Current Pension-Recovery	Line 84	0.0	0.0	0.0	0.0	(1.4)	(1.4)	0.0	0.0	0.0	0.0	0.0
168	End of Year		11.5	0.0	(11.5)	5.7	3.3	(2.5)	(0.0)	(2.5)	(2.5)	(1.2)	0.0
	Customer Crisis Fund												
169	Beginning of Year		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.4	0.1
170	Additions	5.0 L62	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.3	0.3	(0.3)	(0.3)
171	Recovery		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
172	End of Year		0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.4	0.4	0.1	(0.2)

Other Regulatory Accounts
($ million)

Line		Column / Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	End of Year Balances												
173	Demand-Side Management	Line 6	931.8	915.6	(16.3)	954.6	902.5	(52.1)	979.7	927.1	(52.6)	932.0	949.7
174	First Nations Costs	Line 13	131.1	123.6	(7.5)	120.3	104.3	(16.0)	101.0	85.1	(15.9)	71.5	55.8
175	First Nations Settlement Provisions	Line 19	399.2	408.6	9.4	395.7	414.2	18.5	400.7	420.0	19.3	422.6	427.5
176	Site C Project	Line 25	453.1	453.3	0.1	471.5	472.0	0.5	491.0	491.2	0.2	508.5	525.5
177	Future Removal and Site Restoration	Line 30	0.0	2.9	2.9	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0
178	Foreign Exchange Gains/Losses	Line 35	(63.3)	(65.5)	(2.2)	(32.0)	(31.3)	0.6	3.1	7.2	4.1	4.9	5.0
179	Pre-1996 Customer Contributions	Line 39	91.4	91.4	(0.0)	88.2	88.2	(0.0)	83.3	83.3	(0.0)	78.2	73.1
180	Storm Restoration Costs	Line 45	19.7	38.6	19.0	9.8	46.5	36.6	(0.0)	38.1	38.1	19.0	0.0
181	Capital Project Investigation	Line 49	20.1	20.1	(0.0)	15.3	15.3	(0.0)	10.5	10.5	(0.0)	5.2	0.0
182	F2010 ROE Adjustment	Line 52	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
183	Amortization of Capital Additions	Line 58	(6.4)	(8.8)	(2.4)	(3.2)	(5.2)	(2.0)	0.0	20.2	20.2	10.1	0.0
184	Total Finance Charges	Line 63	(203.7)	(215.5)	(11.8)	(101.8)	(139.4)	(37.6)	0.0	(8.8)	(8.8)	(4.4)	0.0
185	Smart Metering & Infrastructure	Line 71	260.8	260.9	0.1	239.1	239.2	0.1	217.3	217.1	(0.2)	195.4	173.7
186	Home Purchase Option Plan	Line 76	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0
187	Non-Current Pension Cost	Line 85	615.4	510.7	(104.7)	557.6	303.4	(254.2)	499.7	(3.0)	(502.7)	(18.9)	(34.9)
188	Waneta	Line 88	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
189	Environmental Provisions	Line 97	337.8	333.2	(4.6)	301.5	309.6	8.0	267.0	276.0	9.0	233.7	193.7
190	Rock Bay Remediation	Line 103	(18.1)	(23.0)	(4.8)	(9.1)	(20.0)	(10.9)	0.0	(20.5)	(20.5)	(10.3)	(0.0)
191	IFRS PP&E	Line 108	961.8	961.8	(0.0)	1,025.4	1,025.4	(0.0)	1,064.4	1,064.4	(0.0)	1,079.2	1,070.6
192	IFRS Pension	Line 112	573.6	573.6	(0.0)	535.4	535.4	(0.0)	497.1	497.1	(0.0)	458.9	420.6
193	Arrow Water Divestiture Costs	Line 118	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0
194	Arrow Water Provision	Line 125	3.0	4.5	1.5	2.8	2.9	0.0	2.7	2.7	0.0	2.6	2.4
195	Remediation	Line 132	3.4	(15.8)	(19.2)	1.7	(28.6)	(30.3)	0.0	(25.3)	(25.3)	(12.7)	0.0
196	Rate Smoothing	Line 137	503.9	488.7	(15.2)	814.9	814.9	(0.0)	1,136.3	(0.0)	(1,136.3)	(0.0)	(0.0)
197	Real Property Sales	Line 143	25.1	28.2	3.2	15.9	37.7	21.9	2.2	44.1	41.9	37.6	30.8
198	Minimum Reconnection Charge	Line 149	(0.0)	0.0	0.0	(0.0)	(0.0)	0.0	(0.0)	0.0	0.0	0.0	0.0
199	Debt Management	Line 154	0.0	(187.1)	(187.1)	0.0	(157.8)	(157.8)	0.0	(260.2)	(260.2)	(247.8)	(235.5)
200	Dismantling Cost	Line 160	0.0	0.0	0.0	0.0	35.4	35.4	0.0	50.9	50.9	25.5	0.0
201	PEB Current Pension Costs	Line 168	11.5	0.0	(11.5)	5.7	3.3	(2.5)	(0.0)	(2.5)	(2.5)	(1.2)	0.0
202	Customer Crisis Fund	Line 172	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.4	0.4	0.1	(0.2)
203	Total		5,051.3	4,700.1	(351.3)	5,409.5	4,967.8	(441.7)	5,756.2	3,915.1	(1,841.1)	3,789.8	3,657.9
	Summary												
204	Regulatory Account Additions		259.7	46.8	(212.9)	217.1	237.7	20.6	201.6	184.0	(17.6)	168.2	162.3
205	Interest on Regulatory Accounts		34.3	34.2	(0.0)	34.1	35.2	1.1	33.5	34.8	1.3	33.2	30.5
206	Regulatory Account Recoveries		(8.0)	57.0	65.1	107.0	188.4	81.3	111.6	(1,023.0)	(1,134.6)	(326.7)	(324.7)
207	Adjustments to Opening Balances		0.0	(0.2)	(0.2)	0.0	0.1	0.1	0.0	(0.0)	(0.0)	0.0	0.0
208	OCI Deferral (Pension)		0.0	(203.2)	(203.2)	0.0	(193.6)	(193.6)	0.0	(248.5)	(248.5)	0.0	0.0
209	Regulatory Account Net Transfers		285.9	(65.4)	(351.3)	358.1	267.7	(90.4)	346.8	(1,052.7)	(1,399.4)	(125.3)	(131.9)
210	**Interest Rate**	8.0 L52	4.03%	3.97%	(0.06%)	4.05%	3.96%	(0.09%)	4.13%	3.98%	(0.15%)	3.88%	3.82%

Reconciliation of Current and Gross Views
($ million)

			F2017			F2018			F2019			F2020	F2021
		Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Forecast	Diff	Plan	Plan
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Cost of Energy												
1	Total Gross	4.0 L40	1,549.3	1,505.5	(43.8)	1,657.8	1,538.7	(119.2)	1,762.9	1,673.4	(89.5)	1,887.0	1,920.2
2	HDA Additions	4.0 L41	0.0	31.0	31.0	0.0	60.4	60.4	0.0	7.5	7.5	0.0	0.0
3	NHDA Additions	4.0 L42	0.0	17.2	17.2	0.0	122.0	122.0	0.0	73.9	73.9	0.0	0.0
4	Deferred Operating HDA	4.0 L43	0.0	(0.1)	(0.1)	0.0	0.3	0.3	0.0	0.9	0.9	0.0	0.0
5	Deferred Operating NHDA	4.0 L44	0.0	(8.9)	(8.9)	0.0	(35.6)	(35.6)	0.0	(0.5)	(0.5)	0.0	0.0
6	Deferred Amortization NHDA	4.0 L45	0.0	(3.3)	(3.3)	0.0	(14.0)	(14.0)	0.0	0.0	0.0	0.0	0.0
7	Deferred Taxes NHDA	4.0 L46	0.0	(0.4)	(0.4)	0.0	(1.9)	(1.9)	0.0	0.0	0.0	0.0	0.0
8	Deferred Provision NHDA	4.0 L47	0.0	0.0	0.0	0.0	1.6	1.6	0.0	0.0	0.0	0.0	0.0
9	Deferred Waneta 1/3 Costs	4.0 L48	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	HDA Recoveries	4.0 L49	(4.7)	(4.7)	(0.0)	(4.8)	(13.8)	(9.0)	(5.1)	(51.4)	(46.3)	(201.6)	(201.6)
11	NHDA Recoveries	4.0 L50	179.3	179.4	0.1	185.5	196.5	10.9	194.0	229.7	35.7	49.6	49.6
12	Total Current		1,723.9	1,715.8	(8.1)	1,838.6	1,854.1	15.6	1,951.8	1,933.5	(18.3)	1,735.1	1,768.2
	Operating Costs												
13	Total Gross	5.0 L123	1,185.0	1,165.1	(19.9)	1,220.0	1,228.7	8.7	1,221.0	1,257.5	36.5	1,224.2	1,229.3
14	Def. Acct. Additions - Operating	5.0 L52	0.0	9.0	9.0	0.0	35.3	35.3	0.0	(0.5)	(0.5)	0.0	0.0
15	Def. Acct. Additions - Provisions	5.0 L102	0.0	0.0	0.0	0.0	(1.6)	(1.6)	0.0	0.0	0.0	0.0	0.0
16	Reg. Acct. Additions - Operating	5.0 L63	(231.3)	(242.9)	(11.6)	(212.7)	(179.8)	32.9	(197.9)	(195.5)	2.4	(157.1)	(150.9)
17	Reg. Acct. Additions - Provisions	5.0 L109	(1.2)	19.5	20.7	10.0	(35.4)	(45.4)	14.0	(16.7)	(30.7)	8.1	8.1
18	Subtotal before Recoveries		952.4	950.6	(1.8)	1,017.3	1,047.1	29.8	1,037.1	1,044.9	7.8	1,075.2	1,086.5
19	Reg. Acct. Recoveries - Operating	5.0 L36	207.5	202.3	(5.2)	214.9	217.9	3.0	214.9	216.3	1.4	172.5	170.9
20	Reg. Acct. Recoveries - Provisions	5.0 L91	(175.7)	(162.0)	13.7	(278.5)	(292.2)	(13.8)	(290.5)	845.8	1,136.3	50.9	47.7
21	Total Current		984.2	990.9	6.8	953.8	972.8	19.0	961.6	2,107.1	1,145.5	1,298.6	1,305.2
	Taxes												
22	Total Gross	6.0 L22	223.3	223.1	(0.2)	231.8	231.1	(0.8)	238.7	242.2	3.5	249.8	262.2
23	Deferral Account Additions	6.0 L23	0.0	0.4	0.4	0.0	1.9	1.9	0.0	0.0	0.0	0.0	0.0
24	Total Current		223.3	223.5	0.2	231.8	232.9	1.1	238.7	242.2	3.5	249.8	262.2
	Amortization												
25	Total Gross	7.0 L16	783.2	777.9	(5.3)	821.1	807.6	(13.4)	850.9	871.5	20.6	915.7	936.5
26	Deferral Account Additions	7.0 L14	0.0	3.3	3.3	0.0	14.0	14.0	0.0	0.0	0.0	0.0	0.0
27	Regulatory Account Additions	7.0 L18	0.0	2.0	2.0	0.0	(0.7)	(0.7)	0.0	(21.8)	(21.8)	0.0	0.0
28	Subtotal before Recoveries		783.2	783.2	0.0	821.1	821.0	(0.1)	850.9	849.6	(1.2)	915.7	936.5
29	Regulatory Account Recoveries	7.0 L31	77.6	77.5	(0.0)	96.5	95.4	(1.1)	104.4	101.2	(3.2)	119.9	123.7
30	Total Current		860.7	860.7	0.0	917.5	916.3	(1.2)	955.3	950.8	(4.5)	1,035.6	1,060.2
	Finance Charges												
31	Total Gross	8.0 L1	708.8	579.2	(129.6)	735.0	805.9	71.0	773.8	684.6	(89.2)	757.5	726.9
32	Total Finance Charge Regulatory Acct. A	8.0 L21	0.0	12.6	12.6	0.0	25.1	25.1	0.0	(28.8)	(28.8)	0.0	0.0
33	Other Regulatory Account Additions	8.0 L3-L8+L22	(27.1)	162.4	189.5	(14.4)	(46.9)	(32.5)	(17.7)	78.8	96.6	(19.2)	(19.5)
34	Interest on Regulatory Accounts	8.0 L25	(75.8)	(75.3)	0.4	(68.3)	(61.6)	6.7	(60.1)	(38.6)	21.5	(24.3)	(27.6)
35	Subtotal before Recoveries		605.9	678.8	72.9	652.3	722.5	70.2	696.0	696.0	0.0	714.0	679.9
36	Regulatory Account Recoveries	8.0 L31	(101.3)	(174.9)	(73.6)	(139.9)	(209.4)	(69.5)	(140.5)	(140.4)	0.0	(16.6)	(17.6)
37	Total Current		504.6	504.0	(0.7)	512.4	513.1	0.7	555.5	555.6	0.0	697.5	662.3

Reconciliation of Current and Gross Views
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Return on Equity												
38	Total Gross	9.0 L32	684.0	683.5	(0.5)	698.0	684.0	(14.0)	712.0	(424.3)	(1,136.3)	712.0	712.0
39	Subtotal before Recoveries		684.0	683.5	(0.5)	698.0	684.0	(14.0)	712.0	(424.3)	(1,136.3)	712.0	712.0
40	Regulatory Account Recoveries	2.2 L51	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Total Current		684.0	683.5	(0.5)	698.0	684.0	(14.0)	712.0	(424.3)	(1,136.3)	712.0	712.0
	Miscellaneous Revenue												
42	Total Gross	15.0 L39	(137.1)	(143.1)	(6.0)	(138.3)	(143.7)	(5.5)	(140.6)	(202.9)	(62.3)	(240.8)	(247.2)
43	Deferral Account Additions	15.0 L35	0.0	0.0	0.0	0.0	0.0	0.0	0.0	51.3	51.3	3.1	3.5
44	Regulatory Account Additions	15.0 L38	0.0	(0.3)	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
45	Subtotal before Recoveries		(137.1)	(143.4)	(6.3)	(138.3)	(143.7)	(5.5)	(140.6)	(151.6)	(11.0)	(237.7)	(243.7)
46	Total Current	15.0 L42	(137.1)	(143.4)	(6.3)	(138.3)	(143.7)	(5.5)	(140.6)	(151.6)	(11.0)	(237.7)	(243.7)
	Inter-Segment Revenue												
47	Powerex - Business Support Allocation	3.1 L14	(2.8)	(2.8)	0.0	(2.8)	(2.8)	0.0	(2.9)	(2.9)	0.0	(2.9)	(2.9)
48	Mark to Market Losses (Gains)	3.1 L15	0.0	(0.2)	(0.2)	0.0	(1.0)	(1.0)	0.0	0.0	0.0	0.0	0.0
49	Powerex PTP Charges	3.4 L18	(11.8)	(9.6)	2.2	(10.1)	(21.2)	(11.1)	(16.6)	(26.7)	(10.1)	(32.5)	(32.5)
50	BC Hydro PTP Charges	3.4 L19	(47.8)	(44.3)	3.5	(51.4)	(41.3)	10.0	(45.9)	(34.7)	11.1	(33.6)	(37.2)
51	Total		(62.5)	(56.9)	5.5	(64.3)	(66.4)	(2.1)	(65.3)	(64.3)	1.0	(69.0)	(72.6)
	Powerex Net Income												
52	Total Gross	1.0 L17	(115.2)	(130.2)	(15.1)	(115.2)	(136.6)	(21.4)	(115.1)	(205.3)	(90.2)	(120.6)	(120.6)
53	TIDA Additions	2.1 L16	0.0	15.1	15.1	0.0	21.4	21.4	0.0	90.2	90.2	0.0	0.0
54	TIDA Recoveries	2.1 L18	48.9	48.9	0.0	50.6	50.5	(0.1)	52.9	62.9	10.0	(12.6)	(12.6)
55	Total Current		(66.3)	(66.2)	0.0	(64.6)	(64.7)	(0.1)	(62.2)	(52.3)	10.0	(133.2)	(133.2)
56	**Powertech Net Income**	1.0 L18	(4.5)	(2.1)	2.4	(4.8)	(3.1)	1.7	(5.1)	(3.3)	1.8	(3.4)	(3.7)
57	**Other Utilities Revenue**	14.0 L18	(12.6)	(13.0)	(0.5)	(12.0)	(11.9)	0.1	(12.1)	(28.6)	(16.5)	(28.6)	(28.7)
58	**Liquefied Natural Gas Revenue**	14.0 L19	(4.4)	(0.4)	4.0	(10.7)	(1.3)	9.4	(10.9)	(0.3)	10.6	0.0	0.0
59	**Deferral Rider Revenue**	14.0 L21	(223.5)	(223.7)	(0.2)	(231.3)	(233.2)	(1.9)	(241.8)	(241.2)	0.7	0.0	0.0
60	**Total Rate Revenue Requirement (Current)**		4,469.9	4,472.6	2.7	4,626.1	4,649.1	23.0	4,836.8	4,823.4	(13.4)	5,256.5	5,288.3

Reconciliation of Current and Gross Views
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Summary - Current Rates View												
61	Cost of Energy	Line 12	1,723.9	1,715.8	(8.1)	1,838.6	1,854.1	15.6	1,951.8	1,933.5	(18.3)	1,735.1	1,768.2
62	Operating Costs	Line 21	984.2	990.9	6.8	953.8	972.8	19.0	961.6	2,107.1	1,145.5	1,298.6	1,305.2
63	Taxes	Line 24	223.3	223.5	0.2	231.8	232.9	1.1	238.7	242.2	3.5	249.8	262.2
64	Amortization	Line 30	860.7	860.7	0.0	917.5	916.3	(1.2)	955.3	950.8	(4.5)	1,035.6	1,060.2
65	Finance Charges	Line 37	504.6	504.0	(0.7)	512.4	513.1	0.7	555.5	555.6	0.0	697.5	662.3
66	Return on Equity	Line 41	684.0	683.5	(0.5)	698.0	684.0	(14.0)	712.0	(424.3)	(1,136.3)	712.0	712.0
67	Miscellaneous Revenues	Line 46	(137.1)	(143.4)	(6.3)	(138.3)	(143.7)	(5.5)	(140.6)	(151.6)	(11.0)	(237.7)	(243.7)
68	Inter-Segment Revenue	Line 51	(62.5)	(56.9)	5.5	(64.3)	(66.4)	(2.1)	(65.3)	(64.3)	1.0	(69.0)	(72.6)
69	Subsidiary Net Income	L55+L56	(70.8)	(68.4)	2.4	(69.3)	(67.7)	1.6	(67.3)	(55.6)	11.7	(136.6)	(136.9)
70	Other Utilities Revenue	Line 57	(12.6)	(13.0)	(0.5)	(12.0)	(11.9)	0.1	(12.1)	(28.6)	(16.5)	(28.6)	(28.7)
71	Liquefied Natural Gas Revenue	Line 58	(4.4)	(0.4)	4.0	(10.7)	(1.3)	9.4	(10.9)	(0.3)	10.6	0.0	0.0
72	Deferral Rider Revenue	Line 59	(223.5)	(223.7)	(0.2)	(231.3)	(233.2)	(1.9)	(241.8)	(241.2)	0.7	0.0	0.0
73	Total Rate Revenue Requirement		4,469.9	4,472.6	2.7	4,626.1	4,649.1	23.0	4,836.8	4,823.4	(13.4)	5,256.5	5,288.3
	Allocation of Current Costs												
74	Generation	3.2 L17	1,406.6	1,408.1	1.5	1,401.9	1,371.9	(30.0)	1,503.1	1,515.3	12.1	1,551.2	1,500.4
75	Transmission	3.4 L21	813.6	830.5	17.0	807.7	828.8	21.1	828.3	828.5	0.2	931.9	930.3
76	Distribution	3.5 L15	979.2	972.4	(6.8)	970.0	974.9	4.9	998.6	954.4	(44.3)	1,175.7	1,190.6
77	Customer Care	3.3 L10	1,581.7	1,567.0	(14.7)	1,769.8	1,787.6	17.8	1,838.9	1,850.9	12.0	1,762.9	1,832.4
78	Business Support	3.1 L17	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0	0.0	(0.0)
79	Subsidiary Net Income	Line 69	(70.8)	(68.4)	2.4	(69.3)	(67.7)	1.6	(67.3)	(55.6)	11.7	(136.6)	(136.9)
80	Other Utilities Revenue	Line 70	(12.6)	(13.0)	(0.5)	(12.0)	(11.9)	0.1	(12.1)	(28.6)	(16.5)	(28.6)	(28.7)
81	Liquefied Natural Gas Revenue	Line 71	(4.4)	(0.4)	4.0	(10.7)	(1.3)	9.4	(10.9)	(0.3)	10.6	0.0	0.0
82	Deferral Rider Revenue	Line 72	(223.5)	(223.7)	(0.2)	(231.3)	(233.2)	(1.9)	(241.8)	(241.2)	0.7	0.0	0.0
83	Total Rate Revenue Requirement		4,469.9	4,472.6	2.7	4,626.1	4,649.1	23.0	4,836.8	4,823.4	(13.4)	5,256.5	5,288.3

Total Current Costs - Business Support
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
1	**Current Operating Costs**	3.6 L60 + L61 (F19 Fcst-F21: 3.6 L6)	94.2	87.2	(7.0)	66.6	67.6	1.0	76.7	1,257.6	1,180.8	389.3	415.2
2	**Taxes**	6.0 L29	15.8	15.7	(0.1)	16.7	16.5	(0.2)	17.2	17.1	(0.1)	18.2	18.7
3	**Current Amortization**	7.0 L37	164.9	167.0	2.2	172.8	181.7	8.8	174.7	162.6	(12.1)	199.8	202.1
4	**Business Support Allocation**	Line 58 (F19 Fcst-F21: L53)	(382.0)	(369.9)	12.1	(328.2)	(328.7)	(0.6)	(349.3)	(352.4)	(3.1)	(659.2)	(688.1)
5	**Miscellaneous Revenue**	15.0 L30	(16.8)	(19.5)	(2.7)	(16.6)	(19.4)	(2.8)	(16.6)	(16.2)	0.4	(16.2)	(16.4)
	Internal Allocations												
6	Generation Capitalized Overhead		9.0	8.8	(0.2)	9.1	7.7	(1.4)	9.2	9.4	0.2	9.4	9.4
7	Transmission Capitalized Overhead		16.7	16.0	(0.6)	16.9	16.9	0.0	17.1	17.8	0.7	16.1	16.3
8	Distribution Capitalized Overhead		42.5	42.1	(0.4)	43.0	44.4	1.5	43.4	43.2	(0.2)	45.5	45.7
9	Generation RSRA Write-off	9.0 L44			0.0			0.0		(502.1)	(502.1)		
10	Transmission RSRA Write-off	9.0 L45			0.0			0.0		(382.5)	(382.5)		
11	Distribution RSRA Write-off	9.0 L46			0.0			0.0		(251.6)	(251.6)		
12	Adj to align with prior approved RRA		58.6	55.5	(3.1)	22.5	17.1	(5.4)	30.4		(30.4)		
13	Total		126.8	122.5	(4.3)	91.4	86.1	(5.3)	100.1	(1,065.9)	(1,166.0)	71.0	71.4
	Inter-Segment Revenue												
14	Powerex - Business Support Allocation		(2.8)	(2.8)	0.0	(2.8)	(2.8)	0.0	(2.9)	(2.9)	0.0	(2.9)	(2.9)
15	Mark to Market Losses (Gains)		0.0	(0.2)	(0.2)	0.0	(1.0)	(1.0)	0.0	0.0	0.0	0.0	0.0
16	Total		(2.8)	(3.0)	(0.2)	(2.8)	(3.8)	(1.0)	(2.9)	(2.9)	0.0	(2.9)	(2.9)
17	**Total**		(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0	0.0	(0.0)
	Internal Allocation by Function:												
	Insurance												
18	Generation		4.2	4.2	0.0	4.2	4.2	0.0	4.2	4.2	0.0	4.3	4.3
19	Transmission		2.5	2.5	0.0	2.5	2.5	0.0	2.5	2.4	(0.1)	2.4	2.4
20	Distribution		2.5	2.5	0.0	2.6	2.5	(0.0)	2.6	2.6	0.0	2.6	2.6
21	Customer Care		0.5	0.5	0.0	0.5	0.5	0.0	0.5	0.5	0.0	0.5	0.5
22	Total		9.7	9.7	0.0	9.7	9.7	0.0	9.7	9.7	0.0	9.7	9.7
	Non-Current Pension Costs												
23	Generation		24.2	24.2	0.0	17.1	17.1	0.0	17.1	28.1	11.1	14.3	14.6
24	Transmission		32.6	32.6	0.0	23.0	23.0	0.0	23.1	29.7	6.5	15.4	15.3
25	Distribution		31.7	31.7	0.0	22.3	22.3	0.0	22.2	28.5	6.3	14.8	14.7
26	Customer Care		6.4	6.4	0.0	4.5	4.5	0.0	4.5	12.9	8.4	5.8	5.8
27	Total		94.9	94.9	0.0	66.9	66.9	0.0	66.9	99.2	32.3	50.3	50.3
	Fleet/MMBU												
28	Generation		7.2	7.2	0.0	7.5	7.5	0.0	7.7	8.2	0.5	8.5	8.6
29	Transmission		25.2	25.2	0.0	26.1	26.1	0.0	26.7	22.5	(4.2)	23.3	23.6
30	Distribution		47.7	47.7	0.0	49.5	49.5	0.0	50.6	52.8	2.1	54.6	55.4
31	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3	1.3	1.3	1.3
32	Total		80.1	80.1	0.0	83.1	83.1	0.0	85.0	84.8	(0.3)	87.6	89.0

Total Current Costs - Business Support
($ million)

Line	Reference / Column	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Total Direct Assignments											
33	Generation	35.6	35.6	0.0	28.7	28.7	0.0	28.9	40.6	11.7	27.1	27.4
34	Transmission	60.3	60.3	0.0	51.6	51.7	0.0	52.4	54.6	2.2	41.1	41.3
35	Distribution	82.0	82.0	0.0	74.4	74.3	(0.0)	75.4	83.8	8.4	71.9	72.6
36	Customer Care	6.9	6.9	0.0	5.0	5.0	0.0	5.0	14.7	9.7	7.6	7.6
37	Business Support	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	Total	184.8	184.8	0.0	159.7	159.7	0.0	161.7	193.7	32.0	147.7	149.0
	Allocators for Balance - %											
39	Generation	28.4%	28.4%	-	28.4%	28.4%	-	28.4%	28.4%	-	28.5%	28.9%
40	Transmission	28.1%	28.1%	-	28.1%	28.1%	-	28.1%	28.1%	-	28.8%	28.5%
41	Distribution	30.5%	30.5%	-	30.5%	30.5%	-	30.5%	30.5%	-	31.2%	30.9%
42	Customer Care	13.0%	13.0%	-	13.0%	13.0%	-	13.0%	13.0%	-	11.6%	11.6%
43	Total	100.0%	100.0%	-	100.0%	100.0%	-	100.0%	100.0%	-	100.0%	100.0%
	Allocation of Balance											
44	Generation	55.9	52.5	(3.4)	47.8	47.9	0.2	53.2	45.0	(8.2)	145.8	156.0
45	Transmission	55.5	52.1	(3.4)	47.4	47.5	0.2	52.8	44.6	(8.1)	147.1	153.9
46	Distribution	60.1	56.4	(3.7)	51.3	51.5	0.2	57.2	48.3	(8.8)	159.4	166.7
47	Customer Care	25.7	24.2	(1.6)	22.0	22.0	0.1	24.5	20.7	(3.8)	59.3	62.5
48	Total	197.2	185.2	(12.1)	168.4	169.0	0.6	187.6	158.7	(28.9)	511.5	539.1
	Total Business Support Allocation											
49	Generation	91.5	88.1	(3.4)	76.5	76.7	0.2	82.1	85.6	3.5	172.8	183.5
50	Transmission	115.8	112.4	(3.4)	99.0	99.2	0.2	105.1	99.2	(5.9)	188.2	195.2
51	Distribution	142.1	138.4	(3.7)	125.7	125.8	0.1	132.6	132.2	(0.4)	231.3	239.3
52	Customer Care	32.6	31.1	(1.6)	27.0	27.0	0.1	29.5	35.4	5.9	66.9	70.2
53	Total	382.0	369.9	(12.1)	328.2	328.7	0.6	349.3	352.4	3.1	659.2	688.1
	Total Business Support Allocation (Prior Approved RRA)											
54	Generation	94.5	90.9	(3.6)	79.2	79.4	0.2	85.5				
55	Transmission	121.4	117.7	(3.7)	102.4	102.6	0.2	109.2				
56	Distribution	142.3	138.6	(3.7)	126.1	126.2	0.1	132.8				
57	Customer Care	23.8	22.8	(1.0)	20.5	20.5	0.1	21.8				
58	Total	382.0	369.9	(12.1)	328.2	328.7	0.6	349.3				

Total Current Costs - Generation
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
1	**Cost of Energy**	4.0 L52	274.6	272.7	(1.9)	245.4	238.8	(6.6)	274.3	242.3	(32.0)	109.6	77.0
2	**Current Operating Costs**	3.6 L51 + L56 (F19 Fcst-F21: 3.6 L2)	206.5	219.7	13.3	219.1	217.1	(2.0)	220.7	229.7	9.1	260.9	239.1
3	**Taxes**	6.0 L25	40.5	40.5	(0.0)	41.6	40.9	(0.7)	43.2	42.2	(1.0)	44.3	46.3
4	**Current Amortization**	7.0 L33	278.2	276.0	(2.2)	295.3	284.8	(10.5)	319.2	324.5	5.3	350.8	360.3
5	**Current Finance Charges**	8.0 L37	211.3	209.5	(1.8)	214.5	212.0	(2.5)	239.3	245.5	6.2	324.9	308.2
6	**Return on Equity**	9.0 L40	286.5	284.2	(2.3)	292.2	282.6	(9.6)	306.8	(187.5)	(494.2)	331.7	331.3
7	**Business Support Allocation**	3.1 L54 (F19 Fcst-F21: 3.1 L49)	94.5	90.9	(3.6)	79.2	79.4	0.2	85.5	85.6	0.1	172.8	183.5
8	**Miscellaneous Revenue**	15.0 L3	(2.0)	(2.3)	(0.3)	(1.8)	(1.9)	(0.0)	(1.9)	(2.1)	(0.2)	(1.9)	(1.9)
	Internal Allocations												
9	GRTA Allocation	3.4 L8	43.3	43.3	0.0	43.3	43.3	0.0	43.3	43.3	0.0	43.3	43.3
10	Generation Real Time Dispatch	3.4 L9	1.6	1.6	(0.0)	1.6	1.6	0.0	1.6	1.6	0.0	2.3	2.3
11	Generation Ancillary Services	3.4 L13	(2.5)	(2.0)	0.5	(2.5)	(2.7)	(0.3)	(2.5)	(2.5)	(0.0)	(2.8)	(2.8)
12	Generation Capitalized Overhead	3.1 L6	(9.0)	(8.8)	0.2	(9.1)	(7.7)	1.4	(9.2)	(9.4)	(0.2)	(9.4)	(9.4)
13	Generation RSRA Write-off	3.1 L9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	502.1	502.1	0.0	0.0
14	Waneta 2/3 Lease revenue from Teck	3.3 L7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(75.2)	(76.7)
15	Adj to align with prior approved RRA		(16.9)	(17.2)	(0.3)	(16.8)	(16.0)	0.8	(17.1)		17.1		
16	Total		16.5	16.9	0.4	16.5	18.4	1.9	16.1	535.1	518.9	(41.8)	(43.3)
17	**Total**		1,406.6	1,408.1	1.5	1,401.9	1,371.9	(30.0)	1,503.1	1,515.3	12.1	1,551.2	1,500.4

Total Current Costs - Customer Care
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
1	**Cost of Energy**	4.0 L54	1,449.3	1,443.0	(6.2)	1,593.2	1,615.4	22.2	1,677.6	1,691.2	13.6	1,625.4	1,691.2
2	**Current Operating Costs**	3.6 L54 + L59 (F19 Fcst-F21: 3.6 L5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	134.1	134.1	79.1	80.0
3	**Taxes**	6.0 L28	2.6	2.6	0.0	4.2	4.2	0.0	2.5	2.6	0.1	0.6	0.6
4	**Current Amortization**	7.0 L36	17.0	17.0	0.0	29.4	29.4	0.0	22.8	22.8	(0.0)	30.2	30.2
5	**Business Support Allocation**	3.1 L57 (F19 Fcst-F21: 3.1 L52)	23.8	22.8	(1.0)	20.5	20.5	0.1	21.8	35.4	13.6	66.9	70.2
6	**Miscellaneous Revenue**	15.0 L25	(24.8)	(24.9)	(0.1)	(24.1)	(23.4)	0.7	(23.6)	(35.3)	(11.6)	(114.5)	(116.4)
	Internal Allocations												
7	Waneta 2/3 Lease revenue from Teck	15.0 L20			0.0			0.0			0.0	75.2	76.7
8	Adj to align with prior approved RRA		113.8	106.4	(7.4)	146.7	141.5	(5.2)	137.8		(137.8)		
9	Total		113.8	106.4	(7.4)	146.7	141.5	(5.2)	137.8	0.0	(137.8)	75.2	76.7
10	**Total**		1,581.7	1,567.0	(14.7)	1,769.8	1,787.6	17.8	1,838.9	1,850.9	12.0	1,762.9	1,832.4

Total Current Costs - Transmission
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
1	**Current Operating Costs**	3.6 L52 + L57 (F19 Fcst-F21: 3.6 L3)	454.6	451.0	(3.6)	444.3	455.0	10.7	432.8	253.6	(179.3)	252.1	256.5
2	**Taxes**	6.0 L26	137.6	137.9	0.3	141.7	143.8	2.1	147.2	152.0	4.8	157.6	163.7
3	**Current Amortization**	7.0 L34	210.2	215.7	5.5	220.8	225.8	5.0	230.7	228.7	(2.0)	235.0	237.3
4	**Current Finance Charges**	8.0 L38	177.4	178.7	1.3	180.0	182.5	2.4	191.0	187.0	(3.9)	223.3	209.0
5	**Return on Equity**	9.0 L41	240.5	242.4	1.9	245.3	243.2	(2.0)	244.8	(142.8)	(387.6)	227.9	224.7
6	**Business Support Allocation**	3.1 L55 (F19 Fcst-F21: 3.1 L50)	121.4	117.7	(3.7)	102.4	102.6	0.2	109.2	99.2	(10.0)	188.2	195.2
7	**Miscellaneous Revenue**	15.0 L10	(43.1)	(44.1)	(0.9)	(41.9)	(43.3)	(1.4)	(42.4)	(41.5)	0.8	(45.9)	(46.6)
	Internal Allocations:												
8	GRTA Allocation		**(43.3)**	**(43.3)**	0.0	**(43.3)**	**(43.3)**	0.0	**(43.3)**	**(43.3)**	0.0	**(43.3)**	**(43.3)**
9	Generation Real Time Dispatch		**(1.6)**	**(1.6)**	0.0	**(1.6)**	**(1.6)**	(0.0)	**(1.6)**	**(1.6)**	0.0	**(2.3)**	**(2.3)**
10	Distribution Real Time Dispatch		**(16.8)**	**(16.7)**	0.1	**(16.4)**	**(16.4)**	(0.0)	**(16.7)**	**(16.7)**	0.0	**(20.0)**	**(20.4)**
11	SDA Allocation to Distribution		**(125.2)**	**(125.6)**	(0.4)	**(128.3)**	**(127.6)**	0.8	**(125.9)**	**(125.9)**	0.0	**(126.5)**	**(128.1)**
12	PTP Allocation to Distribution	L20 + L67	(26.3)	(26.7)	(0.5)	(24.2)	(28.3)	(4.2)	(25.8)	(25.9)	(0.1)	(34.8)	(32.2)
13	Generation Ancillary Services		**2.5**	**2.0**	(0.5)	**2.5**	**2.7**	0.3	**2.5**	**2.5**	0.0	**2.8**	**2.8**
14	Transmission Capitalized Overhead	3.1 L7	(16.7)	(16.0)	0.6	(16.9)	(16.9)	(0.0)	(17.1)	(17.8)	(0.7)	(16.1)	(16.3)
15	Transmission RSRA Write-off	3.1 L10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	382.5	382.5	0.0	0.0
16	Adj to align with prior approved RRA		**(198.0)**	**(186.9)**	11.1	**(195.3)**	**(187.0)**	8.3	**(194.5)**		194.5		
17	Total		(425.3)	(414.8)	10.5	(423.4)	(418.2)	5.2	(422.5)	153.8	576.3	(240.1)	(239.8)
	Inter-Segment Revenue												
18	Powerex PTP Charges		**(11.8)**	**(9.6)**	2.2	**(10.1)**	**(21.2)**	(11.1)	**(16.6)**	**(26.7)**	(10.1)	**(32.5)**	**(32.5)**
19	BC Hydro PTP Charges		**(47.8)**	**(44.3)**	3.5	**(51.4)**	**(41.3)**	10.0	**(45.9)**	**(34.7)**	11.1	**(33.6)**	**(37.2)**
20	Total		(59.7)	(53.9)	5.7	(61.5)	(62.6)	(1.1)	(62.5)	(61.5)	1.0	(66.1)	(69.7)
21	**Total Current Costs**		813.6	830.5	17.0	807.7	828.8	21.1	828.3	828.5	0.2	931.9	930.3
	Transmission Revenue Requirement												
22	Total Current Costs	Line 21	813.6	830.5	17.0	807.7	828.8	21.1	828.3	828.5	0.2	931.9	930.3
23	Adj to offset re-org impact				0.0			0.0			0.0		
24	Adj. Total Current Costs		813.6	830.5	17.0	807.7	828.8	21.1	828.3	828.5	0.2	931.9	930.3
25	PTP Allocation to Distribution	Line 12	26.3	26.7	0.5	24.2	28.3	4.2	25.8	25.9	0.1	34.8	32.2
26	Inter-Segment Revenue	Line 20	59.7	53.9	(5.7)	61.5	62.6	1.1	62.5	61.5	(1.0)	66.1	69.7
27	External OATT Revenue	Line 73	14.0	11.8	(2.2)	13.8	11.4	(2.4)	14.0	11.6	(2.5)	15.4	15.4
28	Total TRR		913.5	923.0	9.6	907.2	931.1	23.9	930.7	927.4	(3.2)	1,048.3	1,047.6

Total Current Costs - Transmission
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	NITS Charge to BC Hydro												
29	Adj. Total Current Costs	Line 24	813.6			807.7			828.3			931.9	930.3
30	Internal Ancillary Services	Line 35	0.0			0.0			0.0			0.0	0.0
31	Internal Scheduling & Dispatch	Line 37	(2.7)			(2.6)			(2.7)			(3.7)	(3.8)
32	Total		810.8	820.1	9.3	805.1	826.2	21.1	825.6	826.0	0.4	928.2	926.5
33	NITS Monthly Rate	Line 32 / 12	67.6	68.3		67.1	68.9		68.8	68.8		77.4	77.2
	Long-Term PTP Rate												
34	Total TRR	Line 28	913.5			907.2			930.7			1,048.3	1,047.6
35	Internal Ancillary Services		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	External Ancillary Services		(2.5)	(2.0)	0.5	(2.5)	(2.7)	(0.3)	(2.5)	(2.5)	(0.0)	(2.8)	(2.8)
37	Internal Scheduling & Dispatch		(2.7)	(2.7)	(0.0)	(2.6)	(2.6)	0.0	(2.7)	(2.5)	0.2	(3.7)	(3.8)
38	External Scheduling & Dispatch		(0.2)	(0.2)	0.0	(0.2)	(0.1)	0.0	(0.2)	(0.1)	0.0	(0.2)	(0.2)
39	Total		908.1			901.9			925.3			1,041.5	1,040.7
40	Maximum Supply (MW)		12,978	12,978		13,124	13,124		13,115	13,171		13,279	13,279
41	Long-Term Firm PTP Rate ($/MW/year)		69,970	70,687		68,719	70,451		70,555	70,518		78,433	78,375
	Maximum Price for Short-Term Firm and Non-Firm (per MW of Reserved Capacity)												
42	Monthly ($/MW/month)		5,830.86	5,890.60		5,726.62	5,870.95		5,879.58	5,876.50		6,536.12	6,531.23
43	Weekly ($/MW/week)		1,345.58	1,359.37		1,321.53	1,354.83		1,356.83	1,356.12		1,508.34	1,507.21
44	Daily ($/MW/day)		191.70	193.66		188.27	193.02		193.30	193.20		214.89	214.73
45	Hourly ($/MW/hour)		7.99	8.07		7.84	8.04		8.05	8.05		8.95	8.95
	Scheduling Fee												
46	Scheduling, Control & Dispatch	L37 + L38	2.9	2.9		2.8	2.7		2.9	2.6		3.9	4.0
47	Total Volume (GWh)		27,734	25,664		28,162	27,707		28,590	29,139		29,388	29,773
48	Scheduling Fee ($/MWh)	L46 / L47	0.105	0.113		0.100	0.099		0.100	0.091		0.133	0.136
	Long-Term PTP Volumes (GWh)												
49	Internal		8,042	8,226	184	8,042	8,448	406	8,042	8,567	526	8,567	8,567
50	External		1,314	1,130	(184)	1,314	908	(406)	1,314	1,039	(275)	1,314	1,314
51	Total		9,356	9,356	0	9,356	9,356	0	9,356	9,606	250	9,881	9,881
	Long-Term PTP Revenue												
52	Internal	L45 * L49	64.3	65.9	1.6	63.05	68.0	4.9	64.7	69.0	4.2	76.7	76.7
53	External	L45 * L50	10.5	9.1	(1.4)	10.3	7.3	(3.0)	10.6	8.4	(2.2)	11.8	11.8
54	Total		74.8	74.9	0.2	73.3	75.2	1.9	75.3	77.3	2.0	88.4	88.4
	Long-Term PTP Average Price ($/MWh)												
55	Internal	L52 / L49	7.99	8.01	0.02	7.84	8.05	0.21	8.05	8.05	0.00	8.95	8.95
56	External	L53 / L50	7.99	8.01	0.02	7.84	8.02	0.18	8.05	8.05	0.00	8.95	8.95
57	Total	L54 / L51	7.99	8.01	0.02	7.84	8.04	0.20	8.05	8.05	0.00	8.95	8.95

Total Current Costs - Transmission
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Short-Term PTP Volumes (GWh)												
58	Internal		9,679	6,608	(3,070)	10,107	8,338	(1,768)	10,535	9,700	(835)	9,700	10,085
59	External		374	288	(85)	374	446	73	374	266	(107)	240	240
60	Total		10,052	6,897	(3,156)	10,480	8,785	(1,696)	10,909	9,966	(942)	9,940	10,325
	Short-Term PTP Revenue												
61	Internal		21.7	14.8	(6.9)	22.6	22.9	0.3	23.6	18.4	(5.2)	24.2	25.2
62	External		0.8	0.6	(0.2)	0.8	1.2	0.4	0.8	0.6	(0.2)	0.6	0.6
63	Total		22.5	15.4	(7.1)	23.4	24.2	0.7	24.4	19.0	(5.4)	24.8	25.8
	Short-Term PTP Average Price ($/MWh)												
64	Internal	L61 / L58	2.24	2.24	0.00	2.24	2.75	0.51	2.24	1.89	(0.34)	2.50	2.50
65	External	L62 / L59	2.24	2.24	0.00	2.24	2.75	0.51	2.24	2.24	0.00	2.50	2.50
66	Total	L63 / L60	2.24	2.24	0.00	2.24	2.75	0.51	2.24	1.90	(0.33)	2.50	2.50
	Total PTP Revenue												
67	Internal	L52 + L61	85.9	80.7	(5.2)	85.7	90.9	5.2	88.3	87.3	(1.0)	100.9	101.9
68	External	L53 + L62	11.3	9.7	(1.6)	11.1	8.5	(2.6)	11.4	9.0	(2.5)	12.4	12.4
69	Total		97.2	90.4	(6.9)	96.8	99.4	2.6	99.7	96.3	(3.4)	113.3	114.2
	Total External OATT Revenue												
70	Total External PTP	Line 68	11.3	9.7	(1.6)	11.1	8.5	(2.6)	11.4	9.0	(2.5)	12.4	12.4
71	External Ancillary Services	Line 36	2.5	2.0	(0.5)	2.5	2.7	0.3	2.5	2.5	0.0	2.8	2.8
72	External Scheduling & Dispatch	Line 38	0.2	0.2	(0.0)	0.2	0.1	(0.0)	0.2	0.1	(0.0)	0.2	0.2
73	Total		14.0	11.8	(2.2)	13.8	11.4	(2.4)	14.0	11.6	(2.5)	15.4	15.4

Total Current Costs - Distribution
($ million)

Line		Reference	F2017			F2018			F2019			F2020	F2021
			RRA	Actual	Diff	RRA	Actual	Diff	RRA	Forecast	Diff	Plan	Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
1	**Current Operating Costs**	3.6 L53 + L58 (F19 Fcst-F21: 3.6 L4)	229.0	233.1	4.1	223.8	233.1	9.3	231.4	232.2	0.8	317.1	314.4
2	**Taxes**	6.0 L27	26.8	26.8	0.0	27.5	27.5	(0.0)	28.6	28.4	(0.3)	29.1	32.9
3	**Current Amortization**	7.0 L35	190.5	184.9	(5.5)	199.2	194.7	(4.6)	207.8	212.2	4.3	219.9	230.3
4	**Current Finance Charges**	8.0 L39	115.8	115.7	(0.1)	117.9	118.7	0.8	125.2	123.0	(2.2)	149.3	145.1
5	**Return on Equity**	9.0 L42	157.0	157.0	(0.0)	160.6	158.2	(2.3)	160.5	(93.9)	(254.4)	152.4	156.0
6	**Business Support Allocation**	3.1 L56 (F19 Fcst-F21: 3.1 L51)	142.3	138.6	(3.7)	126.1	126.2	0.1	132.8	132.2	(0.6)	231.3	239.3
7	**Miscellaneous Revenue**	15.0 L13	(50.4)	(52.7)	(2.3)	(53.9)	(55.7)	(1.9)	(56.2)	(56.5)	(0.4)	(59.2)	(62.3)
	Internal Allocations												
8	Distribution Real Time Dispatch	3.4 L10	16.8	16.7	(0.1)	16.4	16.4	0.0	16.7	16.7	0.0	20.0	20.4
9	SDA Allocation from Transmission	3.4 L11	125.2	125.6	0.4	128.3	127.6	(0.8)	125.9	125.9	0.0	126.5	128.1
10	PTP Allocation to Distribution	3.4 L12	26.3	26.7	0.5	24.2	28.3	4.2	25.8	25.9	0.1	34.8	32.2
11	Distribution Capitalized Overhead	3.1 L8	(42.5)	(42.1)	0.4	(43.0)	(44.4)	(1.5)	(43.4)	(43.2)	0.2	(45.5)	(45.7)
12	Distribution RSRA Write-off	3.1 L11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	251.6	251.6	0.0	0.0
13	Adj to align with prior approved RRA		**42.5**	**42.1**	(0.4)	**43.0**	**44.4**	1.5	**43.4**		(43.4)		
14	Total		168.2	169.0	0.8	168.9	172.2	3.4	168.5	376.9	208.5	135.8	135.0
15	**Total**		979.2	972.4	(6.8)	970.0	974.9	4.9	998.6	954.4	(44.3)	1,175.7	1,190.6

Total Current Operating Costs and Provisions
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
1	**Total Current Operating and Provisions & Other**	5.0 L122	984.2	990.9	6.8	953.8	972.8	19.0	961.6	2,107.1	1,145.5	1,298.6	1,305.2
	Total Internal Allocation												
2	Generation		(228.7)	(240.6)	(11.9)	(230.2)	(243.3)	(13.1)	(231.3)	(229.7)	1.6	(260.9)	(239.1)
3	Transmission		(245.4)	(258.9)	(13.5)	(245.7)	(266.7)	(20.9)	(244.4)	(253.6)	(9.2)	(252.1)	(256.5)
4	Distribution		(228.9)	(223.7)	5.2	(228.9)	(229.5)	(0.6)	(225.8)	(232.2)	(6.3)	(317.1)	(314.4)
5	Customer Care		(113.2)	(105.6)	7.7	(145.5)	(140.6)	5.0	(136.6)	(134.1)	2.5	(79.1)	(80.0)
6	Business Support		(167.9)	(162.1)	5.8	(103.4)	(92.7)	10.7	(123.5)	(1,257.6)	(1,134.1)	(389.3)	(415.2)
7	Total		(984.2)	(990.9)	(6.8)	(953.8)	(972.8)	(19.0)	(961.6)	(2,107.1)	(1,145.5)	(1,298.6)	(1,305.2)
8	**Total**		0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0	(0.0)	0.0	0.0
	Total Internal Allocation by BG												
	Integrated Planning												
9	Generation	3.7 L2	(136.0)	(148.5)	(12.5)	(131.8)	(147.8)	(16.0)	(131.4)	(128.7)	2.7	(141.5)	(133.0)
10	Transmission	3.7 L3	(150.1)	(164.8)	(14.7)	(143.7)	(163.5)	(19.9)	(142.3)	(150.5)	(8.2)	(142.8)	(150.3)
11	Distribution	3.7 L4	(81.7)	(80.2)	1.5	(78.7)	(79.9)	(1.2)	(77.6)	(83.7)	(6.0)	(133.2)	(139.2)
12	Customer Care	3.7 L5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Business Support	3.7 L6	(3.7)	(3.3)	0.4	(3.5)	(3.4)	0.1	(3.5)	(3.8)	(0.3)	(4.2)	(4.1)
14	Total	3.7 L7	(371.5)	(396.7)	(25.3)	(357.6)	(394.6)	(37.0)	(354.8)	(366.7)	(11.9)	(421.7)	(426.7)
	Capital Infrastructure Project Delivery												
15	Generation	3.8 L2	(44.2)	(42.9)	1.3	(48.1)	(46.7)	1.4	(46.7)	(48.3)	(1.5)	(47.2)	(47.8)
16	Transmission	3.8 L3	(30.2)	(29.3)	0.9	(34.8)	(33.5)	1.3	(33.8)	(34.6)	(0.8)	(31.2)	(29.8)
17	Distribution	3.8 L4	(3.4)	(3.7)	(0.2)	(3.6)	(3.6)	0.1	(3.5)	(3.7)	(0.2)	(4.1)	(3.6)
18	Customer Care	3.8 L5	0.3	0.3	0.0	0.3	0.3	0.0	0.3	0.3	0.0	0.3	0.3
19	Business Support	3.8 L6	(32.6)	(32.0)	0.7	(33.6)	(36.1)	(2.5)	(32.8)	(32.7)	0.1	(29.2)	(29.4)
20	Total	3.8 L7	(110.0)	(107.5)	2.6	(119.8)	(119.5)	0.3	(116.4)	(118.9)	(2.4)	(111.4)	(110.2)
	Operations												
21	Generation	3.9 L2	(48.5)	(49.2)	(0.6)	(50.3)	(48.8)	1.5	(53.2)	(52.7)	0.4	(72.1)	(58.2)
22	Transmission	3.9 L3	(65.1)	(64.9)	0.3	(67.3)	(69.7)	(2.4)	(68.3)	(68.5)	(0.1)	(77.2)	(75.4)
23	Distribution	3.9 L4	(111.3)	(107.2)	4.1	(115.0)	(114.3)	0.7	(113.8)	(113.9)	(0.1)	(150.0)	(142.7)
24	Customer Care	3.9 L5	(3.4)	(2.8)	0.6	(3.4)	(3.2)	0.2	(3.4)	(5.7)	(2.3)	(5.7)	(5.9)
25	Business Support	3.9 L6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.8)	(0.1)
26	Total	3.9 L7	(228.3)	(224.0)	4.3	(235.9)	(236.0)	(0.0)	(238.7)	(240.8)	(2.1)	(305.9)	(282.3)
	Safety												
27	Generation	3.10 L2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)
28	Transmission	3.10 L3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)
29	Distribution	3.10 L4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)
30	Customer Care	3.10 L5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Business Support	3.10 L6	(54.6)	(56.0)	(1.4)	(54.6)	(53.6)	1.0	(54.9)	(54.8)	0.2	(56.8)	(57.5)
32	Total	3.10 L7	(54.6)	(56.0)	(1.4)	(54.6)	(53.6)	1.0	(54.9)	(54.8)	0.2	(56.9)	(57.6)

Total Current Operating Costs and Provisions
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Finance, Technology, Supply Chain												
33	Generation	3.11 L2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.2)	(0.1)
34	Transmission	3.11 L3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.9)	(0.9)
35	Distribution	3.11 L4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.2)
36	Customer Care	3.11 L5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	Business Support	3.11 L6	(263.3)	(261.6)	1.7	(264.4)	(254.5)	9.9	(265.0)	(258.5)	6.5	(261.8)	(263.9)
38	Total	3.11 L7	(263.3)	(261.6)	1.7	(264.4)	(254.5)	9.9	(265.0)	(258.5)	6.5	(263.0)	(265.1)
	People, Customer, Corporate Affairs												
39	Generation	3.12 L2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	Transmission	3.12 L3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Distribution	3.12 L4	(32.5)	(32.6)	(0.1)	(31.7)	(31.8)	(0.1)	(31.0)	(31.0)	0.0	(29.6)	(28.6)
42	Customer Care	3.12 L5	(81.5)	(74.1)	7.4	(78.9)	(74.1)	4.8	(79.1)	(74.4)	4.8	(73.7)	(74.4)
43	Business Support	3.12 L6	(42.9)	(41.7)	1.2	(42.9)	(46.7)	(3.7)	(43.4)	(42.6)	0.8	(42.2)	(42.7)
44	Total	3.12 L7	(156.8)	(148.4)	8.4	(153.5)	(152.6)	0.9	(153.5)	(147.9)	5.6	(145.4)	(145.8)
	Other												
45	Generation	3.13 L8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
46	Transmission	3.13 L9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
47	Distribution	3.13 L10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
48	Customer Care	3.13 L11	(28.7)	(29.0)	(0.3)	(63.6)	(63.6)	(0.0)	(54.3)	(54.3)	0.0	0.0	0.0
49	Business Support	3.13 L12	229.1	232.4	3.3	295.6	301.6	6.0	276.2	(865.2)	(1,141.4)	5.7	(17.5)
50	Total	3.13 L13	200.4	203.4	3.0	232.0	238.0	6.0	221.8	(919.6)	(1,141.4)	5.7	(17.5)
	Total Internal Allocation (Prior Approved RRA)												
51	Generation		**(147.8)**	**(163.5)**	(15.7)	**(156.5)**	**(158.0)**	(1.5)	**(158.6)**				
52	Transmission		**(417.1)**	**(406.7)**	10.4	**(407.8)**	**(418.6)**	(10.8)	**(396.3)**				
53	Distribution		**(262.4)**	**(265.6)**	(3.1)	**(258.5)**	**(266.8)**	(8.3)	**(266.7)**				
54	Customer Care		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**				
55	Capital Infrastructure Project Delivery												
56	Generation		**(58.7)**	**(56.3)**	2.4	**(62.6)**	**(59.1)**	3.5	**(62.0)**				
57	Transmission		**(37.5)**	**(44.3)**	(6.8)	**(36.5)**	**(36.3)**	0.1	**(36.5)**				
58	Distribution		**33.4**	**32.5**	(0.9)	**34.7**	**33.8**	(1.0)	**35.3**				
59	Customer Care		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**				
60	Business Support		**(24.0)**	**(22.6)**	1.4	**(26.2)**	**(28.4)**	(2.2)	**(23.4)**				
61	Business Support		**(70.2)**	**(64.5)**	5.6	**(40.4)**	**(39.3)**	1.2	**(53.3)**				
62	Total		(984.2)	(990.9)	(6.8)	(953.8)	(972.8)	(19.0)	(961.6)				

Integrated Planning
Current Operating Costs and Provisions ($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
1	**Current Operating Costs and Provisions & Other**	5.0 L111	371.5	396.7	25.3	357.6	394.6	37.0	354.8	366.7	11.9	421.7	426.7
	Internal Allocations												
2	Generation	Line 19	(136.0)	(148.5)	(12.5)	(131.8)	(147.8)	(16.0)	(131.4)	(128.7)	2.7	(141.5)	(133.0)
3	Transmission	Line 31	(150.1)	(164.8)	(14.7)	(143.7)	(163.5)	(19.9)	(142.3)	(150.5)	(8.2)	(142.8)	(150.3)
4	Distribution	Line 43	(81.7)	(80.2)	1.5	(78.7)	(79.9)	(1.2)	(77.6)	(83.7)	(6.0)	(133.2)	(139.2)
5	Customer Care												
6	Business Support	Line 51	(3.7)	(3.3)	0.4	(3.5)	(3.4)	0.1	(3.5)	(3.8)	(0.3)	(4.2)	(4.1)
7	Total		(371.5)	(396.7)	(25.3)	(357.6)	(394.6)	(37.0)	(354.8)	(366.7)	(11.9)	(421.7)	(426.7)
8	**Total**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:												
	Generation												
9	Energy Planning & Analytics	Line 52	0.8	0.7	(0.1)	0.8	0.7	(0.0)	0.8	0.9	0.1	1.0	1.0
10	Dam Safety	5.1 L2	8.8	8.4	(0.4)	8.9	8.6	(0.3)	9.0	10.0	1.0	10.2	10.3
11	Stations Asset Planning	Line 57	74.8	75.0	0.1	76.9	78.7	1.9	77.4	68.5	(8.9)	70.7	71.5
12	Engineering	Line 67	8.2	7.9	(0.3)	8.3	8.4	0.1	8.4	9.0	0.6	10.2	10.3
13	Business Support	Line 71	5.7	13.8	8.0	3.3	7.7	4.4	3.3	7.0	3.7	5.8	5.9
14	Provisions	Line 75	15.3	20.5	5.2	15.8	25.7	9.9	15.6	15.6	0.0	5.6	6.2
15	Dismantling Expense	Line 79	8.9	8.9	0.0	8.2	8.2	0.0	8.2	8.2	0.0	16.0	6.3
	Regulatory Account Recoveries - Operating Costs												
16	PCB Remediation	Line 84	5.7	5.7	0.0	5.3	5.3	(0.0)	5.0	5.0	0.0	7.8	8.0
17	Asbestos Remediation	Line 89	7.7	7.7	0.0	4.3	4.3	0.0	3.6	4.5	0.9	2.7	2.4
18	Dismantling Cost	Line 94	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	11.1
19	Subtotal		136.0	148.5	12.5	131.8	147.8	16.0	131.4	128.7	(2.7)	141.5	133.0
	Transmission												
20	Energy Planning & Analytics	Line 53	1.0	0.9	(0.1)	1.0	0.9	(0.0)	1.0	1.1	0.1	1.3	1.3
21	Stations Asset Planning	Line 58	27.4	27.5	0.1	28.1	28.8	0.7	28.4	25.1	(3.3)	25.9	26.2
22	Line Asset Planning	Line 61	55.5	53.4	(2.2)	55.9	57.0	1.2	55.5	60.6	5.1	63.5	63.9
23	Interconnections and Shared Assets	Line 64	4.4	5.0	0.6	4.5	4.3	(0.1)	4.5	4.5	(0.0)	5.1	5.2
24	Engineering	Line 68	9.2	8.8	(0.3)	9.3	9.4	0.1	9.4	10.0	0.6	11.4	11.5
25	Business Support	Line 72	7.2	17.3	10.1	4.2	9.7	5.5	4.2	8.9	4.6	7.3	7.3
26	Provisions	Line 76	19.3	25.8	6.5	19.9	32.4	12.5	19.7	19.7	0.0	8.4	8.9
27	Dismantling Expense	Line 80	10.3	10.3	0.0	9.6	9.6	0.0	9.6	9.6	0.0	5.0	11.5
	Regulatory Account Recoveries - Operating Costs												
28	PCB Remediation	Line 85	6.7	6.7	0.0	6.2	6.2	(0.0)	5.9	5.9	0.0	9.1	9.3
29	Asbestos Remediation	Line 90	9.0	9.0	0.0	5.1	5.1	0.0	4.2	5.3	1.1	3.1	2.8
30	Dismantling Cost	Line 95	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	2.5
31	Subtotal		150.1	164.8	14.7	143.7	163.5	19.9	142.3	150.5	8.2	142.8	150.3

Integrated Planning
Current Operating Costs and Provisions ($ million)

			F2017			F2018			F2019			F2020	F2021
		Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Forecast	Diff	Plan	Plan
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Distribution												
32	Energy Planning & Analytics	Line 54	1.1	0.9	(0.1)	1.0	1.0	(0.0)	1.0	1.1	0.1	1.3	1.3
33	Stations Asset Planning	Line 59	0.4	0.4	0.0	0.4	0.4	0.0	0.4	0.4	(0.1)	0.4	0.4
34	Line Asset Planning	Line 62	55.8	53.6	(2.2)	56.1	57.3	1.2	55.8	60.9	5.1	63.8	64.2
35	Interconnections and Shared Assets	Line 65	4.6	5.2	0.7	4.6	4.5	(0.1)	4.7	4.7	(0.0)	5.3	5.4
36	Engineering	Line 69	2.5	2.4	(0.1)	2.6	2.6	0.0	2.6	2.8	0.2	3.1	3.2
37	Business Support	Line 73	0.1	0.2	0.1	0.0	0.1	0.1	0.0	0.1	0.1	0.1	(0.7)
38	Provisions	Line 77	0.2	0.3	0.1	0.2	0.4	0.1	0.2	0.2	0.0	26.4	27.8
39	Dismantling Expense	Line 81	6.8	6.8	0.0	6.3	6.3	0.0	6.2	6.2	0.0	11.2	16.7
	Regulatory Account Recoveries - Operating Costs												
40	PCB Remediation	Line 86	4.4	4.4	0.0	4.0	4.0	(0.0)	3.8	3.8	0.0	6.0	6.0
41	Asbestos Remediation	Line 91	5.9	5.9	0.0	3.3	3.3	0.0	2.7	3.4	0.7	2.0	1.8
42	Dismantling Cost	Line 96	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.5	13.1
43	Subtotal		81.7	80.2	(1.5)	78.7	79.9	1.2	77.6	83.7	6.0	133.2	139.2
	Business Support												
44	Energy Planning & Analytics	Line 55	3.6	3.2	(0.4)	3.4	3.3	(0.2)	3.5	3.8	0.3	4.4	4.8
45	Business Unit Support	Line 74	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
46	Provisions	Line 78	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
47	Dismantling Expense	Line 82	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.3
	Regulatory Account Recoveries - Operating Costs												
48	PCB Remediation	Line 87	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
49	Asbestos Remediation	Line 92	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
50	Dismantling Cost	Line 97	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.0)	(1.0)
51	Subtotal		3.7	3.3	(0.4)	3.5	3.4	(0.1)	3.5	3.8	0.3	4.2	4.1
	Energy Planning & Analytics												
52	Generation		0.8	0.7	(0.1)	0.8	0.7	(0.0)	0.8	0.9	0.1	1.0	1.0
53	Transmission		1.0	0.9	(0.1)	1.0	0.9	(0.0)	1.0	1.1	0.1	1.3	1.3
54	Distribution		1.1	0.9	(0.1)	1.0	1.0	(0.0)	1.0	1.1	0.1	1.3	1.3
55	Business Support		3.6	3.2	(0.4)	3.4	3.3	(0.2)	3.5	3.8	0.3	4.4	4.8
56	Total	5.1 L1	6.5	5.7	(0.8)	6.2	5.9	(0.3)	6.3	6.8	0.5	7.9	8.4
	Stations Asset Planning												
57	Generation		74.8	75.0	0.1	76.9	78.7	1.9	77.4	68.5	(8.9)	70.7	71.5
58	Transmission		27.4	27.5	0.1	28.1	28.8	0.7	28.4	25.1	(3.3)	25.9	26.2
59	Distribution		0.4	0.4	0.0	0.4	0.4	0.0	0.4	0.4	(0.1)	0.4	0.4
60	Total	5.1 L3	102.7	102.8	0.2	105.4	108.0	2.6	106.2	94.0	(12.2)	97.0	98.1
	Line Asset Planning												
61	Transmission		55.5	53.4	(2.2)	55.9	57.0	1.2	55.5	60.6	5.1	63.5	63.9
62	Distribution		55.8	53.6	(2.2)	56.1	57.3	1.2	55.8	60.9	5.1	63.8	64.2
63	Total	5.1 L4	111.3	107.0	(4.3)	112.0	114.3	2.3	111.3	121.4	10.2	127.2	128.1

Integrated Planning
Current Operating Costs and Provisions ($ million)

			F2017			F2018			F2019			F2020	F2021
		Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Forecast	Diff	Plan	Plan
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Interconnections and Shared Assets												
64	Transmission		4.4	5.0	0.6	4.5	4.3	(0.1)	4.5	4.5	(0.0)	5.1	5.2
65	Distribution		4.6	5.2	0.7	4.6	4.5	(0.1)	4.7	4.7	(0.0)	5.3	5.4
66	Total	5.1 L5	9.0	10.3	1.3	9.1	8.8	(0.3)	9.2	9.2	(0.1)	10.5	10.6
	Engineering												
67	Generation		8.2	7.9	(0.3)	8.3	8.4	0.1	8.4	9.0	0.6	10.2	10.3
68	Transmission		9.2	8.8	(0.3)	9.3	9.4	0.1	9.4	10.0	0.6	11.4	11.5
69	Distribution		2.5	2.4	(0.1)	2.6	2.6	0.0	2.6	2.8	0.2	3.1	3.2
70	Total	5.1 L6	19.9	19.2	(0.7)	20.2	20.5	0.3	20.5	21.8	1.4	24.7	25.1
	Business Unit Support												
71	Generation		5.7	13.8	8.0	3.3	7.7	4.4	3.3	7.0	3.7	5.8	5.9
72	Transmission		7.2	17.3	10.1	4.2	9.7	5.5	4.2	8.9	4.6	7.3	7.3
73	Distribution		0.1	0.2	0.1	0.0	0.1	0.1	0.0	0.1	0.1	0.1	(0.7)
74	Business Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
75	Total	5.1 L7	13.1	31.3	18.2	7.6	17.6	10.0	7.6	16.0	8.4	13.2	12.5
	Provisions												
75	Generation		15.3	20.5	5.2	15.8	25.7	9.9	15.6	15.6	0.0	5.6	6.2
76	Transmission		19.3	25.8	6.5	19.9	32.4	12.5	19.7	19.7	0.0	8.4	8.9
77	Distribution		0.2	0.3	0.1	0.2	0.4	0.1	0.2	0.2	0.0	26.4	27.8
78	Business Support		0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
79	Total	5.0 L65	34.9	46.6	11.8	35.9	58.5	22.6	35.6	35.6	0.0	40.5	42.9
	Dismantling Expense												
79	Generation		8.9	8.9	0.0	8.2	8.2	0.0	8.2	8.2	0.0	16.0	6.3
80	Transmission		10.3	10.3	0.0	9.6	9.6	0.0	9.6	9.6	0.0	5.0	11.5
81	Distribution		6.8	6.8	0.0	6.3	6.3	0.0	6.2	6.2	0.0	11.2	16.7
82	Business Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.3
83	Total	5.0 L72	26.0	26.0	0.0	24.0	24.0	0.0	24.0	24.0	0.0	33.0	34.8
	Regulatory Account Recoveries												
	PCB Remediation												
84	Generation		5.7	5.7	0.0	5.3	5.3	(0.0)	5.0	5.0	0.0	7.8	8.0
85	Transmission		6.7	6.7	0.0	6.2	6.2	(0.0)	5.9	5.9	0.0	9.1	9.3
86	Distribution		4.4	4.4	0.0	4.0	4.0	(0.0)	3.8	3.8	0.0	6.0	6.0
87	Business Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
88	Total	5.0 L78	16.8	16.8	0.0	15.5	15.5	(0.0)	14.7	14.7	0.0	22.9	23.3
	Regulatory Account Recoveries												
	Asbestos Remediation												
89	Generation		7.7	7.7	0.0	4.3	4.3	0.0	3.6	4.5	0.9	2.7	2.4
90	Transmission		9.0	9.0	0.0	5.1	5.1	0.0	4.2	5.3	1.1	3.1	2.8
91	Distribution		5.9	5.9	0.0	3.3	3.3	0.0	2.7	3.4	0.7	2.0	1.8
92	Business Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
93	Total	5.0 L81	22.5	22.5	0.0	12.7	12.7	0.0	10.5	13.2	2.7	7.9	7.0

Integrated Planning
Current Operating Costs and Provisions ($ million)

			F2017			F2018			F2019			F2020	F2021
		Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Forecast	Diff	Plan	Plan
Line		Column	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Regulatory Account Recoveries												
	Dismantling Cost												
94	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	11.1
95	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	2.5
96	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.5	13.1
97	Business Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.0)	(1.0)
98	Total	5.0 L84	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.7	25.7

Capital Infrastructure Project Delivery
Current Operating Costs and Provisions ($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
1	**Current Operating Costs and Provisions & Other**	5.0 L112	110.0	107.5	(2.6)	119.8	119.5	(0.3)	116.4	118.9	2.4	111.4	110.2
	Internal Allocations												
2	Generation	Line 18	(44.2)	(42.9)	1.3	(48.1)	(46.7)	1.4	(46.7)	(48.3)	(1.5)	(47.2)	(47.8)
3	Transmission	Line 27	(30.2)	(29.3)	0.9	(34.8)	(33.5)	1.3	(33.8)	(34.6)	(0.8)	(31.2)	(29.8)
4	Distribution	Line 35	(3.4)	(3.7)	(0.2)	(3.6)	(3.6)	0.1	(3.5)	(3.7)	(0.2)	(4.1)	(3.6)
5	Customer Care	Line 37	0.3	0.3	0.0	0.3	0.3	0.0	0.3	0.3	0.0	0.3	0.3
6	Business Support	Line 44	(32.6)	(32.0)	0.7	(33.6)	(36.1)	(2.5)	(32.8)	(32.7)	0.1	(29.2)	(29.4)
7	Total		(110.0)	(107.5)	2.6	(119.8)	(119.5)	0.3	(116.4)	(118.9)	(2.4)	(111.4)	(110.2)
8	**Total**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:												
	Generation												
9	Project Delivery	Line 45	5.7	5.4	(0.3)	6.1	5.8	(0.3)	6.1	6.0	(0.2)	6.0	7.5
10	Indigenous Relations	Line 49	1.7	2.0	0.3	1.7	1.7	(0.0)	1.7	1.8	0.1	1.7	1.8
11	Environment	Line 54	21.5	20.8	(0.7)	21.8	21.4	(0.5)	22.0	23.1	1.1	23.6	23.7
12	Properties	Line 59	0.7	0.7	0.0	0.7	0.7	0.0	0.7	0.7	(0.0)	0.7	0.7
13	Business Unit Support	Line 64	0.3	0.3	(0.0)	0.3	0.3	(0.1)	0.3	0.3	(0.0)	0.3	0.4
14	Dismantling Expense	Line 69	0.7	0.7	0.0	1.5	1.5	0.0	0.3	0.3	0.0	0.7	0.0
15	Real Property Sales	Line 74	(4.9)	(4.9)	0.0	(4.9)	(4.9)	0.0	(4.9)	(4.9)	0.0	(4.9)	(4.9)
	Regulatory Account Recoveries - Operating Costs												
16	First Nation Costs	Line 79	13.5	13.0	(0.5)	16.1	15.5	(0.6)	15.6	16.2	0.6	13.9	13.4
17	Capital Project Investigation	5.0 L27	4.8	4.8	0.0	4.8	4.8	0.0	4.8	4.8	0.0	5.2	5.2
18	Subtotal		44.2	42.9	(1.3)	48.1	46.7	(1.4)	46.7	48.3	1.5	47.2	47.8
	Transmission												
19	Project Delivery	Line 46	7.3	7.0	(0.4)	7.7	7.4	(0.4)	7.8	7.6	(0.2)	7.6	6.9
20	Indigenous Relations	Line 50	2.1	2.5	0.4	2.1	2.1	(0.0)	2.1	2.2	0.1	2.1	2.1
21	Environment	Line 55	2.7	2.6	(0.1)	2.7	2.7	(0.1)	2.8	2.9	0.1	2.9	3.0
22	Properties	Line 60	0.1	0.2	0.0	0.2	0.2	0.0	0.2	0.2	(0.0)	0.1	0.1
23	Business Unit Support	Line 65	0.1	0.1	(0.0)	0.1	0.1	(0.0)	0.1	0.1	(0.0)	0.1	0.1
24	Dismantling Expense	Line 70	0.3	0.3	0.0	0.6	0.6	0.0	0.1	0.1	0.0	0.2	0.1
25	Real Property Sales	Line 75	(2.7)	(2.7)	0.0	(2.7)	(2.7)	0.0	(2.7)	(2.7)	0.0	(2.7)	(2.8)
	Regulatory Account Recoveries - Operating Costs												
26	First Nation Costs	Line 80	20.3	19.5	(0.8)	24.1	23.2	(0.9)	23.4	24.3	0.8	20.8	20.2
27	Subtotal		30.2	29.3	(0.9)	34.8	33.5	(1.3)	33.8	34.6	0.8	31.2	29.8
	Distribution												
28	Project Delivery	Line 47	0.4	0.3	(0.0)	0.4	0.4	(0.0)	0.4	0.4	(0.0)	0.4	0.1
29	Indigenous Relations	Line 51	2.0	2.3	0.4	2.0	2.0	(0.0)	2.0	2.0	0.1	2.0	2.0
30	Environment	Line 56	2.9	2.8	(0.1)	2.9	2.9	(0.1)	2.9	3.1	0.1	3.1	3.2
31	Properties	Line 61	0.1	0.1	0.0	0.1	0.1	0.0	0.1	0.1	(0.0)	0.1	0.1
32	Business Unit Support	Line 66	0.1	0.1	(0.0)	0.1	0.0	(0.0)	0.1	0.1	(0.0)	0.1	0.1
33	Dismantling Expense	Line 71	0.1	0.1	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.5	0.1
34	Real Property Sales	Line 76	(2.0)	(2.0)	0.0	(2.0)	(2.0)	0.0	(2.0)	(2.0)	0.0	(2.0)	(2.0)
35	Subtotal		3.4	3.7	0.2	3.6	3.6	(0.1)	3.5	3.7	0.2	4.1	3.6

Capital Infrastructure Project Delivery
Current Operating Costs and Provisions ($ million)

			F2017			F2018			F2019			F2020	F2021
		Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Forecast	Diff	Plan	Plan
Line		Column	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Customer Care												
36	Real Property Sales	Line 77	(0.3)	(0.3)	0.0	(0.3)	(0.3)	0.0	(0.3)	(0.3)	0.0	(0.3)	(0.3)
37	Subtotal		(0.3)	(0.3)	0.0	(0.3)	(0.3)	0.0	(0.3)	(0.3)	0.0	(0.3)	(0.3)
	Business Support												
38	Indigenous Relations	Line 52	0.4	0.4	0.1	0.4	0.4	(0.0)	0.4	0.4	0.0	0.4	0.4
39	Environment	Line 57	0.1	0.1	(0.0)	0.1	0.1	(0.0)	0.1	0.1	0.0	0.1	0.1
40	Properties	Line 62	31.2	31.3	0.1	31.5	31.7	0.2	31.8	31.7	(0.1)	28.4	28.6
41	Business Unit Support	Line 67	0.3	0.3	(0.0)	0.3	0.2	(0.1)	0.3	0.3	(0.0)	0.3	0.3
42	Provisions	5.0 L66	0.0	(0.8)	(0.8)	0.0	2.4	2.4	0.0	0.0	0.0	0.0	0.0
43	Dismantling Expense	Line 72	0.7	0.7	0.0	1.3	1.3	0.0	0.2	0.2	0.0	0.0	0.0
44	Subtotal		32.6	32.0	(0.7)	33.6	36.1	2.5	32.8	32.7	(0.1)	29.2	29.4
	Project Delivery												
45	Generation		5.7	5.4	(0.3)	6.1	5.8	(0.3)	6.1	6.0	(0.2)	6.0	7.5
46	Transmission		7.3	7.0	(0.4)	7.7	7.4	(0.4)	7.8	7.6	(0.2)	7.6	6.9
47	Distribution		0.4	0.3	(0.0)	0.4	0.4	(0.0)	0.4	0.4	(0.0)	0.4	0.1
48	Total	5.2 L1	13.4	12.7	(0.6)	14.2	13.5	(0.7)	14.3	13.9	(0.4)	14.0	14.5
	Indigenous Relations												
49	Generation		1.7	2.0	0.3	1.7	1.7	(0.0)	1.7	1.8	0.1	1.7	1.8
50	Transmission		2.1	2.5	0.4	2.1	2.1	(0.0)	2.1	2.2	0.1	2.1	2.1
51	Distribution		2.0	2.3	0.4	2.0	2.0	(0.0)	2.0	2.0	0.1	2.0	2.0
52	Business Support		0.4	0.4	0.1	0.4	0.4	(0.0)	0.4	0.4	0.0	0.4	0.4
53	Total	5.2 L2	6.1	7.3	1.2	6.1	6.1	(0.0)	6.1	6.3	0.2	6.1	6.3
	Environment												
54	Generation		21.5	20.8	(0.7)	21.8	21.4	(0.5)	22.0	23.1	1.1	23.6	23.7
55	Transmission		2.7	2.6	(0.1)	2.7	2.7	(0.1)	2.8	2.9	0.1	2.9	3.0
56	Distribution		2.9	2.8	(0.1)	2.9	2.9	(0.1)	2.9	3.1	0.1	3.1	3.2
57	Business Support		0.1	0.1	(0.0)	0.1	0.1	(0.0)	0.1	0.1	0.0	0.1	0.1
58	Total	5.2 L3	27.2	26.2	(0.9)	27.5	27.0	(0.6)	27.8	29.2	1.4	29.8	30.0
	Properties												
59	Generation		0.7	0.7	0.0	0.7	0.7	0.0	0.7	0.7	(0.0)	0.7	0.7
60	Transmission		0.1	0.2	0.0	0.2	0.2	0.0	0.2	0.2	(0.0)	0.1	0.1
61	Distribution		0.1	0.1	0.0	0.1	0.1	0.0	0.1	0.1	(0.0)	0.1	0.1
62	Business Support		31.2	31.3	0.1	31.5	31.7	0.2	31.8	31.7	(0.1)	28.4	28.6
63	Total	5.2 L4	32.2	32.2	0.1	32.5	32.7	0.2	32.8	32.7	(0.1)	29.3	29.5
	Business Unit Support												
64	Generation		0.3	0.3	(0.0)	0.3	0.3	(0.1)	0.3	0.3	(0.0)	0.3	0.4
65	Transmission		0.1	0.1	(0.0)	0.1	0.1	(0.0)	0.1	0.1	(0.0)	0.1	0.1
66	Distribution		0.1	0.1	(0.0)	0.1	0.0	(0.0)	0.1	0.1	(0.0)	0.1	0.1
67	Business Support		0.3	0.3	(0.0)	0.3	0.2	(0.1)	0.3	0.3	(0.0)	0.3	0.3
68	Total	5.2 L5	0.8	0.7	(0.1)	0.8	0.7	(0.2)	0.8	0.8	(0.0)	0.8	0.9

Capital Infrastructure Project Delivery
Current Operating Costs and Provisions ($ million)

			F2017			F2018			F2019			F2020	F2021
		Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Forecast	Diff	Plan	Plan
Line		Column	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Dismantling Expense												
69	Generation		0.7	0.7	0.0	1.5	1.5	0.0	0.3	0.3	0.0	0.7	0.0
70	Transmission		0.3	0.3	0.0	0.6	0.6	0.0	0.1	0.1	0.0	0.2	0.1
71	Distribution		0.1	0.1	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.5	0.1
72	Business Support		0.7	0.7	0.0	1.3	1.3	0.0	0.2	0.2	0.0	0.0	0.0
73	Total	5.0 L73	1.8	1.8	0.0	3.7	3.7	0.0	0.7	0.7	0.0	1.5	0.3
	Real Property Sales												
74	Generation		(4.9)	(4.9)	0.0	(4.9)	(4.9)	0.0	(4.9)	(4.9)	0.0	(4.9)	(4.9)
75	Transmission		(2.7)	(2.7)	0.0	(2.7)	(2.7)	0.0	(2.7)	(2.7)	0.0	(2.7)	(2.8)
76	Distribution		(2.0)	(2.0)	0.0	(2.0)	(2.0)	0.0	(2.0)	(2.0)	0.0	(2.0)	(2.0)
77	Customer Care		(0.3)	(0.3)	0.0	(0.3)	(0.3)	0.0	(0.3)	(0.3)	0.0	(0.3)	(0.3)
78	Total	5.0 L76	(10.0)	(10.0)	0.0	(10.0)	(10.0)	0.0	(10.0)	(10.0)	0.0	(10.0)	(10.0)
	Regulatory Account Recoveries												
	First Nation Costs												
79	Generation		13.5	13.0	(0.5)	16.1	15.5	(0.6)	15.6	16.2	0.6	13.9	13.4
80	Transmission		20.3	19.5	(0.8)	24.1	23.2	(0.9)	23.4	24.3	0.8	20.8	20.2
81	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
82	Business Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
83	Total	5.0 L25	33.8	32.4	(1.3)	40.2	38.7	(1.5)	39.0	40.4	1.4	34.7	33.6

Operations
Current Operating Costs and Provisions ($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
1	**Current Operating Costs and Provisions & Other**	5.0 L113	228.3	224.0	(4.3)	235.9	236.0	0.0	238.7	240.8	2.1	305.9	282.3
	Internal Allocations												
2	Generation	Line 22	(48.5)	(49.2)	(0.6)	(50.3)	(48.8)	1.5	(53.2)	(52.7)	0.4	(72.1)	(58.2)
3	Transmission	Line 35	(65.1)	(64.9)	0.3	(67.3)	(69.7)	(2.4)	(68.3)	(68.5)	(0.1)	(77.2)	(75.4)
4	Distribution	Line 49	(111.3)	(107.2)	4.1	(115.0)	(114.3)	0.7	(113.8)	(113.9)	(0.1)	(150.0)	(142.7)
5	Customer Care	Line 55	(3.4)	(2.8)	0.6	(3.4)	(3.2)	0.2	(3.4)	(5.7)	(2.3)	(5.7)	(5.9)
6	Business Support	Line 58	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.8)	(0.1)
7	Total		(228.3)	(224.0)	4.3	(235.9)	(236.0)	(0.0)	(238.7)	(240.8)	(2.1)	(305.9)	(282.3)
8	**Total**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:												
	Generation												
9	Program and Contract Management	Line 59	0.2	0.2	(0.0)	0.2	0.2	(0.0)	0.2	0.2	(0.0)	0.2	0.2
10	Line Field Operations	Line 63	0.1	0.1	0.0	0.1	0.1	0.0	0.1	0.1	(0.0)	0.2	0.2
11	Stations Field Operations	Line 67	27.0	27.3	0.3	27.0	25.9	(1.1)	30.9	30.4	(0.5)	34.8	35.2
12	Construction Services	Line 71	2.7	2.3	(0.4)	2.8	2.5	(0.3)	2.8	2.6	(0.2)	2.7	2.7
13	Generation System Operations	5.3 L6	14.5	16.0	1.5	14.7	14.2	(0.5)	14.8	14.6	(0.2)	15.0	15.2
14	T&D System Operations	Line 75	0.4	0.4	0.0	0.4	0.4	0.0	0.4	0.4	0.0	0.4	0.4
15	Business Unit Support	Line 78	0.8	0.7	(0.1)	0.8	0.8	(0.0)	0.8	1.4	0.5	1.3	1.4
16	Dismantling Expense	Line 83	0.8	0.8	0.0	2.0	2.0	0.0	1.5	1.5	0.0	15.7	1.4
17	Provisions	Line 88	0.9	0.7	(0.2)	1.0	1.0	0.0	0.9	0.9	0.0	0.9	1.0
	Regulatory Account Recoveries - Provisions & Other												
18	PCB Remediation	Line 93	0.4	0.4	(0.0)	0.8	0.8	(0.0)	0.1	0.1	0.0	0.2	0.2
19	Asbestos Remediation	Line 98	0.3	0.3	0.0	0.5	0.5	0.0	0.5	0.5	(0.0)	0.6	0.2
20	Arrow Water Divestiture Costs	Line 103	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Arrow Water Provision	Line 108	0.4	0.1	(0.4)	0.1	0.4	0.4	0.1	0.1	(0.0)	0.1	0.1
22	Subtotal		48.5	49.2	0.6	50.3	48.8	(1.5)	53.2	52.7	(0.4)	72.1	58.2
	Transmission												
23	Program and Contract Management	Line 60	3.4	2.9	(0.5)	3.5	2.9	(0.5)	3.5	3.2	(0.4)	3.5	3.5
24	Line Field Operations	Line 64	4.6	4.8	0.1	4.7	4.9	0.2	4.7	4.7	(0.0)	5.6	5.7
25	Stations Field Operations	Line 68	9.3	9.5	0.1	9.4	9.0	(0.4)	10.7	10.5	(0.2)	12.0	12.2
26	Construction Services	Line 72	8.4	7.1	(1.3)	8.6	7.8	(0.8)	8.7	8.0	(0.6)	8.3	8.4
27	T&D System Operations	Line 76	35.9	37.9	2.0	36.4	40.0	3.6	37.0	37.9	0.8	39.4	39.9
28	Business Unit Support	Line 79	0.8	0.6	(0.1)	0.8	0.7	(0.0)	0.8	1.3	0.5	1.3	1.3
29	Dismantling Expense	Line 84	0.7	0.7	0.0	1.9	1.9	0.0	1.4	1.4	0.0	5.0	2.6
30	Provisions	Line 89	0.9	0.7	(0.2)	0.9	0.9	0.0	0.8	0.8	0.0	1.4	1.5
	Regulatory Account Recoveries - Provisions & Other												
31	PCB Remediation	Line 94	0.3	0.3	(0.0)	0.8	0.8	(0.0)	0.1	0.1	0.0	0.2	0.2
32	Asbestos Remediation	Line 99	0.3	0.3	0.0	0.5	0.5	0.0	0.5	0.5	(0.0)	0.6	0.2
33	Arrow Water Divestiture Costs	Line 104	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Arrow Water Provision	Line 109	0.4	0.1	(0.4)	0.1	0.4	0.3	0.1	0.1	(0.0)	0.1	0.1
35	Subtotal		65.1	64.9	(0.3)	67.3	69.7	2.4	68.3	68.5	0.1	77.2	75.4

Operations
Current Operating Costs and Provisions ($ million)

			F2017			F2018			F2019			F2020	F2021
		Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Forecast	Diff	Plan	Plan
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Distribution												
36	Program and Contract Management	Line 61	10.2	8.6	(1.6)	10.4	8.8	(1.6)	10.5	9.5	(1.1)	10.3	10.5
37	Line Field Operations	Line 65	62.9	64.9	2.0	63.4	66.5	3.2	63.9	63.4	(0.5)	76.5	77.2
38	Stations Field Operations	Line 69	4.7	4.8	0.1	4.7	4.5	(0.2)	5.4	5.3	(0.1)	6.1	6.1
39	Distribution Design & Customer Connect	5.3 L4	12.8	10.2	(2.6)	13.1	10.6	(2.5)	13.5	14.3	0.9	14.8	15.1
40	Construction Services	Line 73	2.3	2.0	(0.4)	2.4	2.1	(0.2)	2.4	2.2	(0.2)	2.3	2.3
41	Business Unit Support	Line 80	1.6	1.4	(0.3)	1.7	1.6	(0.1)	1.7	2.8	1.1	2.8	2.8
42	Dismantling Expense	Line 85	1.6	1.6	0.0	4.1	4.1	0.0	3.1	3.1	0.0	11.0	3.8
43	Provisions	Line 90	1.9	1.5	(0.4)	2.0	2.0	0.0	1.9	1.9	0.0	4.3	4.7
	Regulatory Account Recoveries - Operating Costs												
44	Storm Restoration	5.0 L26	10.8	10.8	0.0	10.4	10.4	(0.0)	10.0	10.0	0.0	20.1	19.4
45	PCB Remediation	Line 95	0.7	0.7	(0.0)	1.7	1.7	(0.0)	0.3	0.3	0.0	0.5	0.4
46	Asbestos Remediation	Line 100	0.7	0.7	0.0	1.0	1.0	0.0	1.0	1.0	(0.0)	1.3	0.5
47	Arrow Water Divestiture Costs	Line 105	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
48	Arrow Water Provision	Line 110	0.9	0.1	(0.8)	0.2	0.9	0.8	0.2	0.2	(0.0)	0.2	0.2
49	Subtotal		111.3	107.2	(4.1)	115.0	114.3	(0.7)	113.8	113.9	0.1	150.0	142.7
	Customer Care												
50	Business Unit Support (incl. Waneta 2/3)	Line 81	3.4	2.8	(0.6)	3.4	3.2	(0.2)	3.4	5.7	2.3	5.7	5.9
	Regulatory Account Recoveries - Operating Costs												
51	PCB Remediation	Line 96	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
52	Asbestos Remediation	Line 101	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
53	Arrow Water Divestiture Costs	Line 106	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Arrow Water Provision	Line 111	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
55	Subtotal		3.4	2.8	(0.6)	3.4	3.2	(0.2)	3.4	5.7	2.3	5.7	5.9
	Business Support												
56	Dismantling Expense	Line 86	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.1
57	Provisions	Line 91	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
58	Subtotal		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.1
	Program and Contract Management												
59	Generation		0.2	0.2	(0.0)	0.2	0.2	(0.0)	0.2	0.2	(0.0)	0.2	0.2
60	Transmission		3.4	2.9	(0.5)	3.5	2.9	(0.5)	3.5	3.2	(0.4)	3.5	3.5
61	Distribution		10.2	8.6	(1.6)	10.4	8.8	(1.6)	10.5	9.5	(1.1)	10.3	10.5
62	Total	5.3 L1	13.8	11.6	(2.2)	14.1	11.9	(2.2)	14.3	12.8	(1.5)	14.0	14.2
	Line Field Operations												
63	Generation		0.1	0.1	0.0	0.1	0.1	0.0	0.1	0.1	(0.0)	0.2	0.2
64	Transmission		4.6	4.8	0.1	4.7	4.9	0.2	4.7	4.7	(0.0)	5.6	5.7
65	Distribution		62.9	64.9	2.0	63.4	66.5	3.2	63.9	63.4	(0.5)	76.5	77.2
66	Total	5.3 L2	67.7	69.8	2.1	68.2	71.6	3.4	68.7	68.2	(0.5)	82.3	83.1
	Stations Field Operations												
67	Generation		27.0	27.3	0.3	27.0	25.9	(1.1)	30.9	30.4	(0.5)	34.8	35.2
68	Transmission		9.3	9.5	0.1	9.4	9.0	(0.4)	10.7	10.5	(0.2)	12.0	12.2
69	Distribution		4.7	4.8	0.1	4.7	4.5	(0.2)	5.4	5.3	(0.1)	6.1	6.1
70	Total	5.3 L3	41.0	41.5	0.5	41.1	39.4	(1.7)	46.9	46.2	(0.7)	52.9	53.5

Operations
Current Operating Costs and Provisions ($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Construction Services												
71	Generation		2.7	2.3	(0.4)	2.8	2.5	(0.3)	2.8	2.6	(0.2)	2.7	2.7
72	Transmission		8.4	7.1	(1.3)	8.6	7.8	(0.8)	8.7	8.0	(0.6)	8.3	8.4
73	Distribution		2.3	2.0	(0.4)	2.4	2.1	(0.2)	2.4	2.2	(0.2)	2.3	2.3
74	Total	5.3 L5	13.5	11.4	(2.1)	13.7	12.4	(1.3)	13.9	12.8	(1.0)	13.2	13.3
	T&D System Operations												
75	Generation		0.4	0.4	0.0	0.4	0.4	0.0	0.4	0.4	0.0	0.4	0.4
76	Transmission		35.9	37.9	2.0	36.4	40.0	3.6	37.0	37.9	0.8	39.4	39.9
77	Total	5.3 L7	36.2	38.2	2.0	36.7	40.4	3.6	37.4	38.3	0.9	39.8	40.3
	Business Unit Support												
78	Generation		0.8	0.7	(0.1)	0.8	0.8	(0.0)	0.8	1.4	0.5	1.3	1.4
79	Transmission		0.8	0.6	(0.1)	0.8	0.7	(0.0)	0.8	1.3	0.5	1.3	1.3
80	Distribution		1.6	1.4	(0.3)	1.7	1.6	(0.1)	1.7	2.8	1.1	2.8	2.8
81	Customer Care		3.4	2.8	(0.6)	3.4	3.2	(0.2)	3.4	5.7	2.3	5.7	5.9
82	Total	5.3 L8+L12	6.6	5.4	(1.1)	6.6	6.3	(0.4)	6.7	11.1	4.4	11.1	11.3
	Dismantling Expense												
83	Generation		0.8	0.8	0.0	2.0	2.0	0.0	1.5	1.5	0.0	15.7	1.4
84	Transmission		0.7	0.7	0.0	1.9	1.9	0.0	1.4	1.4	0.0	5.0	2.6
85	Distribution		1.6	1.6	0.0	4.1	4.1	0.0	3.1	3.1	0.0	11.0	3.8
86	Business Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.1
87	Total	5.0 L74	3.1	3.1	0.0	8.0	8.0	0.0	6.0	6.0	0.0	32.4	7.8
	Provisions												
88	Generation		0.9	0.7	(0.2)	1.0	1.0	0.0	0.9	0.9	0.0	0.9	1.0
89	Transmission		0.9	0.7	(0.2)	0.9	0.9	0.0	0.8	0.8	0.0	1.4	1.5
90	Distribution		1.9	1.5	(0.4)	2.0	2.0	0.0	1.9	1.9	0.0	4.3	4.7
91	Business Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
92	Total	5.0 L67	3.7	2.9	(0.9)	3.8	3.9	0.1	3.6	3.6	0.0	6.5	7.2
	Regulatory Account Recoveries												
	PCB Remediation												
93	Generation		0.4	0.4	(0.0)	0.8	0.8	(0.0)	0.1	0.1	0.0	0.2	0.2
94	Transmission		0.3	0.3	(0.0)	0.8	0.8	(0.0)	0.1	0.1	0.0	0.2	0.2
95	Distribution		0.7	0.7	(0.0)	1.7	1.7	(0.0)	0.3	0.3	0.0	0.5	0.4
96	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
97	Total	5.0 L79	1.4	1.4	(0.0)	3.2	3.2	(0.0)	0.5	0.5	0.0	0.9	0.7
	Regulatory Account Recoveries												
	Asbestos Remediation												
98	Generation		0.3	0.3	0.0	0.5	0.5	0.0	0.5	0.5	(0.0)	0.6	0.2
99	Transmission		0.3	0.3	0.0	0.5	0.5	0.0	0.5	0.5	(0.0)	0.6	0.2
100	Distribution		0.7	0.7	0.0	1.0	1.0	0.0	1.0	1.0	(0.0)	1.3	0.5
101	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
102	Total	5.0 L82	1.3	1.3	0.0	2.0	2.0	0.0	2.0	2.0	(0.1)	2.5	0.9

Operations
Current Operating Costs and Provisions ($ million)

			F2017			F2018			F2019			F2020	F2021
		Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Forecast	Diff	Plan	Plan
Line		Column	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Regulatory Account Recoveries												
	Arrow Water Divestiture Costs												
103	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
104	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
105	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
106	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
107	Total	5.0 L88	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Regulatory Account Recoveries												
	Arrow Water Provision												
108	Generation		0.4	0.1	(0.4)	0.1	0.4	0.4	0.1	0.1	(0.0)	0.1	0.1
109	Transmission		0.4	0.1	(0.4)	0.1	0.4	0.3	0.1	0.1	(0.0)	0.1	0.1
110	Distribution		0.9	0.1	(0.8)	0.2	0.9	0.8	0.2	0.2	(0.0)	0.2	0.2
111	Customer Care		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
112	Total	5.0 L89	1.8	0.3	(1.5)	0.3	1.8	1.5	0.3	0.3	(0.0)	0.3	0.3

Safety
Current Operating Costs and Provisions ($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
1	**Current Operating Costs and Provisions & Other**	5.0 L114	54.6	56.0	1.4	54.6	53.6	(1.0)	54.9	54.8	(0.2)	56.9	57.6
	Internal Allocations												
2	Generation	Line 17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)
3	Transmission	Line 18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)
4	Distribution	Line 19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)
5	Customer Care				0.0			0.0			0.0		
6	Business Support	Line 16	(54.6)	(56.0)	(1.4)	(54.6)	(53.6)	1.0	(54.9)	(54.8)	0.2	(56.8)	(57.5)
7	Total		(54.6)	(56.0)	(1.4)	(54.6)	(53.6)	1.0	(54.9)	(54.8)	0.2	(56.9)	(57.6)
8	**Total**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:												
	Business Support												
9	Safety System and Assurance	5.4 L1	14.9	14.5	(0.4)	14.8	14.7	(0.1)	14.7	12.9	(1.7)	13.1	13.3
10	Learning and Development	5.4 L2	25.0	25.7	0.7	25.0	23.2	(1.8)	25.4	25.5	0.1	25.8	26.2
11	Field Safety Services	5.4 L3	4.9	5.7	0.8	5.0	5.7	0.7	5.1	6.2	1.1	6.6	6.7
12	Security and Emergency Management	5.4 L4	9.3	9.4	0.2	9.3	9.2	(0.1)	9.3	9.6	0.3	10.7	10.8
13	Business Unit Support	5.4 L5	0.5	0.6	0.1	0.5	0.6	0.1	0.5	0.6	0.1	0.6	0.6
14	Provisions	5.0 L68	0.0	0.0	0.0	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.0
	Regulatory Account Recoveries - Provisions & Other												
15	Dismantling Cost	Line 20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)
16	Subtotal		54.6	56.0	1.4	54.6	53.6	(1.0)	54.9	54.8	(0.2)	56.8	57.5
	Regulatory Account Recoveries												
	Dismantling Cost												
17	Generation		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**
18	Transmission		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**
19	Distribution		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**
20	Business Support		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**(0.0)**	**(0.0)**
21	Total	5.0 L85	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1

Finance, Technology, Supply Chain
Current Operating Costs and Provisions ($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
1	**Current Operating Costs and Provisions & Other**	5.0 L115	263.3	261.6	(1.7)	264.4	254.5	(9.9)	265.0	258.5	(6.5)	263.0	265.1
	Internal Allocations												
2	Generation	L21+L26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.2)	(0.1)
3	Transmission	Line 12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.9)	(0.9)
4	Distribution	L23+L28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.2)
5	Customer Care				0.0			0.0			0.0		
6	Business Support	Line 20	(263.3)	(261.6)	1.7	(264.4)	(254.5)	9.9	(265.0)	(258.5)	6.5	(261.8)	(263.9)
7	Total		(263.3)	(261.6)	1.7	(264.4)	(254.5)	9.9	(265.0)	(258.5)	6.5	(263.0)	(265.1)
8	**Total**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:												
	Transmission												
9	Technology - MODS costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.8
10	Dismantling Expense	Line 22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Regulatory Account Recoveries - Provisions & Other												
11	Dismantling Cost	Line 27	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Subtotal		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.9
	Business Support												
13	Finance	5.5 L1	29.7	28.7	(1.0)	30.2	28.7	(1.4)	30.7	30.8	0.1	31.6	32.1
14	Technology (excl. MODS costs)	5.5 L2- Line 9	141.1	134.5	(6.6)	141.3	128.3	(13.0)	140.5	133.7	(6.8)	134.9	135.5
15	Supply Chain	5.5 L3	91.8	89.9	(1.9)	92.2	89.0	(3.2)	93.0	93.3	0.2	94.5	95.5
16	Business Unit Support	5.5 L4	0.8	0.7	(0.0)	0.8	0.7	(0.0)	0.8	0.8	(0.0)	0.8	0.8
17	Provisions	5.0 L69	0.0	7.8	7.8	0.0	7.8	7.8	0.0	0.0	0.0	0.0	0.0
18	Dismantling Expense	Line 24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Regulatory Account Recoveries - Provisions & Other												
19	Dismantling Cost	Line 29	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)
20	Subtotal		263.3	261.6	(1.7)	264.4	254.5	(9.9)	265.0	258.5	(6.5)	261.8	263.9
	Dismantling Expense												
21	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
22	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
24	Business Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	Total	5.0 L75	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2
	Regulatory Account Recoveries												
	Dismantling Cost												
26	Generation		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
27	Transmission		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
29	Business Support		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)
30	Total	5.0 L86	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2

People, Customer, Corporate Affairs
Current Operating Costs and Provisions ($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
1	**Current Operating Costs and Provisions & Other**	5.0 L116	156.8	148.4	(8.4)	153.5	152.6	(0.9)	153.5	147.9	(5.6)	145.4	145.8
	Internal Allocations												
2	Generation				0.0			0.0			0.0		
3	Transmission				0.0			0.0			0.0		
4	Distribution	Line 10	(32.5)	(32.6)	(0.1)	(31.7)	(31.8)	(0.1)	(31.0)	(31.0)	0.0	(29.6)	(28.6)
5	Customer Care	Line 15	(81.5)	(74.1)	7.4	(78.9)	(74.1)	4.8	(79.1)	(74.4)	4.8	(73.7)	(74.4)
6	Business Support	Line 22	(42.9)	(41.7)	1.2	(42.9)	(46.7)	(3.7)	(43.4)	(42.6)	0.8	(42.2)	(42.7)
7	Total		(156.8)	(148.4)	8.4	(153.5)	(152.6)	0.9	(153.5)	(147.9)	5.6	(145.4)	(145.8)
8	**Total**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Allocation by Function:												
	Distribution												
	Regulatory Account Recoveries - Operating Costs												
9	Smart Metering & Infrastructure	5.0 L28	32.5	32.6	0.1	31.7	31.8	0.1	31.0	31.0	0.0	29.6	28.6
10	Subtotal		32.5	32.6	0.1	31.7	31.8	0.1	31.0	31.0	0.0	29.6	28.6
	Customer Care												
11	Customer Services	5.6 L2	76.2	68.9	(7.3)	73.6	68.7	(4.9)	73.8	65.0	(8.8)	63.1	63.8
12	Conservation and Energy Management	5.6 L3	0.6	0.6	(0.0)	0.6	0.5	(0.1)	0.6	0.6	(0.0)	0.6	0.6
13	Power Acquisitions and Contract Management	5.6 L4	4.6	4.6	(0.1)	4.7	4.9	0.2	4.8	4.8	(0.0)	4.7	4.7
14	Customer Crisis Fund	5.6 L13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	4.0	5.3	5.3
15	Subtotal		81.5	74.1	(7.4)	78.9	74.1	(4.8)	79.1	74.4	(4.8)	73.7	74.4
	Business Support												
16	Human Resources	5.6 L1	22.9	21.6	(1.3)	23.1	22.1	(1.0)	23.3	21.1	(2.2)	21.1	21.4
17	Communications and Community Engagement	5.6 L5	12.8	12.4	(0.4)	12.6	13.7	1.1	12.7	13.6	0.9	12.9	13.0
18	Regulatory and Rates	5.6 L6	6.0	5.8	(0.2)	6.1	5.4	(0.7)	6.2	6.2	0.0	6.3	6.4
19	Ethics and Merit Office	5.6 L7	0.4	0.5	0.1	0.4	0.6	0.3	0.4	0.8	0.5	1.0	1.0
20	Business Unit Support	5.6 L8	0.7	0.8	0.0	0.8	0.7	(0.0)	0.8	0.8	(0.0)	0.8	0.8
21	Provisions	5.0 L70	0.0	0.5	0.5	0.0	4.0	4.0	0.0	0.0	0.0	0.0	0.0
22	Subtotal		42.9	41.7	(1.2)	42.9	46.7	3.7	43.4	42.6	(0.8)	42.2	42.7

Other
Current Operating Costs and Provisions ($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
1	**Current Operating Costs and Provisions & Other**	5.0 L117	(274.0)	(262.6)	11.4	(305.8)	(305.9)	(0.1)	(295.8)	856.0	1,151.8	(20.4)	2.8
2	**Non-Current PEB - Pension**	5.0 L118	57.9	59.3	1.4	57.9	57.9	0.0	57.9	57.9	0.0	16.0	16.0
3	**PEB Current Pension Costs**	5.0 L119	5.7	0.0	(5.7)	5.7	5.7	0.0	5.7	5.7	0.0	(1.2)	(1.2)
4	**PEB CPC - F17-F19 RRA Compliance Filing Adjustment**	5.0 L120	0.0	0.0	0.0	0.0	4.3	4.3	0.0	0.0	0.0	0.0	0.0
5	**F17-F19 RRA Compliance Filing Adjustme**	5.0 L121	10.1	0.0	(10.1)	10.2	0.0	(10.2)	10.4	0.0	(10.4)	0.0	0.0
6	**Subtotal**		73.7	59.3	(3.0)	73.8	67.9	(6.0)	74.0	63.6	1,141.4	14.7	14.7
7	**Total Current Operating and Provisions & Other**		(200.4)	(203.4)	(3.0)	(232.0)	(238.0)	(6.0)	(221.8)	919.6	1,141.4	(5.7)	17.5
	Internal Allocations												
8	Generation				0.0			0.0			0.0		
9	Transmission				0.0			0.0			0.0		
10	Distribution				0.0			0.0			0.0		
11	Customer Care	Line 18	(28.7)	(29.0)	(0.3)	(63.6)	(63.6)	(0.0)	(54.3)	(54.3)	0.0	0.0	0.0
12	Business Support	Line 35	229.1	232.4	3.3	295.6	301.6	6.0	276.2	(865.2)	(1,141.4)	5.7	(17.5)
13	Total		200.4	203.4	3.0	232.0	238.0	6.0	221.8	(919.6)	(1,141.4)	5.7	(17.5)
14	**Total**		0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0	(0.0)	0.0	0.0
	Internal Allocation by Function:												
	Customer Care												
15	Independent Power Producer Capital Leas	5.7 L8	28.2	28.2	0.0	63.6	63.6	0.0	54.3	54.3	0.0	0.0	0.0
	Regulatory Account Recoveries												
	- Operating Costs												
16	Home Purchase Offer Plan	5.0 L29	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Minimum Reconnection Charge	5.0 L30	0.5	0.9	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Subtotal		28.7	29.0	0.3	63.6	63.6	0.0	54.3	54.3	0.0	0.0	0.0
	Business Support												
19	Office of the General Counsel	5.7 L1	12.2	11.1	(1.0)	12.3	10.6	(1.7)	12.3	12.2	(0.2)	11.7	11.8
20	President and Chief Operating Officer	5.7 L2	0.9	1.0	0.0	1.0	0.8	(0.1)	1.0	0.8	(0.1)	0.9	0.9
21	Corporate Costs	5.7 L4	17.2	13.1	(4.1)	18.4	28.4	10.0	19.7	38.9	19.2	13.0	13.0
22	Capitalized Costs	5.7 L5	(283.0)	(281.8)	1.2	(283.8)	(283.9)	(0.1)	(284.6)	(285.3)	(0.7)	(285.8)	(286.2)
23	IFRS Ineligible Capitalized Costs	5.7 L7	102.9	102.9	0.0	125.3	125.3	0.0	147.7	147.7	0.0	170.1	192.5
	Regulatory Account Recoveries												
	- Operating Costs												
24	IFRS PP&E	5.0 L34	23.2	23.2	(0.0)	26.0	26.0	(0.0)	28.2	28.2	0.0	29.9	31.0
25	IFRS Pension	5.0 L35	38.2	38.2	(0.0)	38.2	38.2	(0.0)	38.2	38.2	0.0	38.2	38.2
26	Provisions	5.0 L71	5.3	5.0	(0.3)	5.5	12.5	7.0	5.9	5.8	(0.1)	12.2	11.9
	Regulatory Account Recoveries												
	- Provisions & Other												
27	PCB Remediation	5.0 L80	0.1	0.1	(0.0)	0.2	0.2	(0.0)	0.0	0.0	0.0	0.0	0.0
28	Asbestos Remediation	5.0 L83	0.6	0.6	0.0	1.8	1.8	0.0	2.7	0.1	(2.6)	0.2	0.0
29	Rock Bay Remediation	5.0 L87	(3.8)	(3.8)	0.0	(3.2)	(3.2)	0.0	0.0	0.0	0.0	(10.8)	(10.4)
30	Rate Smoothing	5.0 L90	(216.5)	(201.2)	15.2	(311.0)	(326.2)	(15.2)	(321.4)	814.9	1,136.3	0.0	0.0
31	Non-Current PEB - Pension	5.0 L118	57.9	59.3	1.4	57.9	57.9	0.0	57.9	57.9	0.0	16.0	16.0
32	PEB Current Pension Costs	5.0 L119	5.7	0.0	(5.7)	5.7	5.7	0.0	5.7	5.7	0.0	(1.2)	(1.2)
33	PEB CPC - F17-F19 RRA Compliance Filing Adjustment	5.0 L120	0.0	0.0	0.0	0.0	4.3	4.3	0.0	0.0	0.0	0.0	0.0
34	F17-F19 RRA Compliance Filing Adjustme	5.0 L121	10.1	0.0	(10.1)	10.2	0.0	(10.2)	10.4	0.0	(10.4)	0.0	0.0
35	Subtotal		(229.1)	(232.4)	(3.3)	(295.6)	(301.6)	(6.0)	(276.2)	865.2	1,141.4	(5.7)	17.5

Cost of Energy
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Sources of Supply (GWh)												
	Heritage Energy												
1	Water Rentals		48,560	48,736	176	47,219	47,926	707	46,368	42,340	(4,028)	44,262	44,999
2	Natural Gas for Thermal Generation		224	74	(151)	232	91	(141)	234	172	(62)	192	193
3	Exchange Net		(115)	(253)	(138)	(323)	599	923	(354)	138	492	(171)	(196)
4	Total		48,669	48,557	(112)	47,128	48,616	1,488	46,248	42,650	(3,598)	44,283	44,996
	Non-Heritage Energy												
5	IPPs and Long-Term Commitments		13,375	13,644	269	15,002	14,354	(648)	15,199	14,631	(568)	15,449	16,040
6	Non-Integrated Area		117	118	0	119	115	(5)	120	112	(8)	118	120
7	Total		13,493	13,762	270	15,121	14,469	(653)	15,320	14,744	(576)	15,566	16,159
	Market Energy												
8	Market Electricity Purchases		230	131	(98)	747	150	(597)	934	2,077	1,143	1,504	648
9	Surplus Sales		(4,962)	(5,756)	(794)	(5,556)	(5,072)	484	(4,517)	(2,230)	2,287	(2,409)	(3,087)
10	Net Purchases (Sales) from Powerex		(267)	138	404	(253)	(557)	(304)	105	537	432	177	90
11	Total		(5,000)	(5,488)	(488)	(5,062)	(5,479)	(417)	(3,478)	384	3,862	(727)	(2,349)
12	**Total Sources of Supply**	L4+L7+L11	57,162	56,832	(331)	57,187	57,606	419	58,089	57,777	(312)	59,121	58,806
13	**Less Line Loss and System Use**		(5,302)	(4,937)	365	(5,349)	(5,504)	(155)	(5,425)	(5,173)	252	(5,554)	(5,553)
14	**Total Domestic Sales**	14.0 L10	51,860	51,895	35	51,838	52,102	264	52,664	52,604	(60)	53,567	53,253
15	**Line Loss as % of Sales**		10.22%	9.51%	-0.71%	10.32%	10.56%	0.24%	10.30%	9.83%	-0.47%	10.37%	10.43%
	Unit Costs ($/MWh)												
16	Water Rentals		8.0	7.9	(0.0)	7.6	7.5	(0.0)	7.7	8.5	0.9	7.8	7.8
17	Natural Gas for Thermal Generation		66.5	128.9	62.3	45.4	37.7	(7.7)	45.9	44.1	(1.8)	42.4	44.3
18	IPPs and Long-Term Commitments		92.3	88.9	(3.4)	91.3	91.4	0.1	94.7	90.7	(4.0)	99.6	99.8
19	Non-Integrated Area		209.6	211.8	2.2	229.4	231.0	1.6	258.9	238.9	(20.0)	268.4	280.9
20	Market Electricity Purchases		37.5	25.8	(11.7)	40.5	24.4	(16.1)	38.5	42.9	4.4	26.6	28.1
21	Surplus Sales		(23.8)	(23.1)	0.7	(27.1)	(27.5)	(0.4)	(28.6)	(51.6)	(23.0)	(40.3)	(36.1)
22	Total Weighted Cost		29.9	29.0	(0.9)	32.0	29.5	(2.4)	33.5	31.8	(1.7)	35.2	36.1
	Cost of Energy ($ million)												
	Heritage Energy												
23	Water Rentals		386.7	387.0	0.4	356.8	361.6	4.8	356.4	361.8	5.4	343.1	349.1
24	Natural Gas for Thermal Generation		14.9	9.5	(5.4)	10.5	3.4	(7.1)	10.7	7.6	(3.2)	8.1	8.5
25	Domestic Transmission - Other		22.6	22.5	(0.1)	22.3	22.5	0.2	22.1	22.6	0.5	22.5	22.4
26	Columbia River Treaty Related Agreements		(23.1)	(23.3)	(0.2)	(10.4)	(40.6)	(30.2)	(7.2)	(59.5)	(52.3)	3.3	(2.5)
27	Remissions and Other		(37.3)	(41.3)	(4.0)	(37.8)	(38.0)	(0.1)	(33.1)	(33.3)	(0.2)	(26.1)	(26.8)
28	Total		363.8	354.4	(9.3)	341.5	309.0	(32.5)	349.0	299.3	(49.7)	350.9	350.8

Cost of Energy
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Non-Heritage Energy												
29	IPPs and Long-Term Commitments		1,234.4	1,213.1	(21.3)	1,369.7	1,311.6	(58.1)	1,439.3	1,326.6	(112.7)	1,538.5	1,601.1
30	Non-Integrated Area		24.6	25.0	0.4	27.4	26.5	(0.9)	31.1	26.9	(4.3)	31.6	33.6
31	Gas & Other Transportation		10.6	11.7	1.1	10.1	13.1	3.0	6.1	9.2	3.1	2.8	2.7
32	Water Rentals (Waneta 2/3)	15.0 L22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4	2.4	3.5	3.7
33	Total		1,269.6	1,249.7	(19.9)	1,407.2	1,351.1	(56.0)	1,476.5	1,365.1	(111.5)	1,576.3	1,641.1
	Market Energy												
34	Market Electricity Purchases		8.6	3.4	(5.2)	30.2	3.7	(26.6)	35.9	89.1	53.2	40.0	18.2
35	Surplus Sales		(118.1)	(132.8)	(14.6)	(150.4)	(139.4)	11.0	(129.2)	(115.0)	14.2	(97.1)	(111.4)
36	Net Purchases (Sales) from Powerex		(6.5)	2.3	8.8	(6.0)	(10.9)	(4.9)	0.7	16.4	15.6	(0.5)	0.5
37	Domestic Transmission - Export		31.8	28.3	(3.5)	35.4	25.2	(10.2)	29.9	18.5	(11.4)	17.4	21.0
38	Total		(84.1)	(98.7)	(14.6)	(90.8)	(121.5)	(30.7)	(62.6)	9.0	71.6	(40.2)	(71.7)
39	**Total Gross COE**	L28+L33+L38	1,549.3	1,505.5	(43.8)	1,657.8	1,538.7	(119.2)	1,762.9	1,673.4	(89.5)	1,887.0	1,920.2
	Current Cost of Energy												
40	Gross Cost of Energy	Line 39	1,549.3	1,505.5	(43.8)	1,657.8	1,538.7	(119.2)	1,762.9	1,673.4	(89.5)	1,887.0	1,920.2
41	HDA Additions	2.1 L3	0.0	31.0	31.0	0.0	60.4	60.4	0.0	7.5	7.5	0.0	0.0
42	NHDA Additions	2.1 L9+L10	0.0	17.2	17.2	0.0	122.0	122.0	0.0	73.9	73.9	0.0	0.0
43	Deferred Operating HDA	Line 64	0.0	(0.1)	(0.1)	0.0	0.3	0.3	0.0	0.9	0.9	0.0	0.0
44	Deferred Operating NHDA	Line 75	0.0	(8.9)	(8.9)	0.0	(35.6)	(35.6)	0.0	(0.5)	(0.5)	0.0	0.0
45	Deferred Amortization NHDA	Line 76	0.0	(3.3)	(3.3)	0.0	(14.0)	(14.0)	0.0	0.0	0.0	0.0	0.0
46	Deferred Taxes NHDA	Line 77	0.0	(0.4)	(0.4)	0.0	(1.9)	(1.9)	0.0	0.0	0.0	0.0	0.0
47	Deferred Provision NHDA	Line 78	0.0	0.0	0.0	0.0	1.6	1.6	0.0	0.0	0.0	0.0	0.0
48	Deferred Waneta 1/3 Costs	2.2 L87+L88	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
49	HDA Recoveries	2.1 L5	(4.7)	(4.7)	(0.0)	(4.8)	(13.8)	(9.0)	(5.1)	(51.4)	(46.3)	(201.6)	(201.6)
50	NHDA Recoveries	2.1 L12	179.3	179.4	0.1	185.5	196.5	10.9	194.0	229.7	35.7	49.6	49.6
51	**Total Current COE**		1,723.9	1,715.8	(8.1)	1,838.6	1,854.1	15.6	1,951.8	1,933.5	(18.3)	1,735.1	1,768.2
	Total Current COE by Function												
52	Generation		274.6	272.7	(1.9)	245.4	238.8	(6.6)	274.3	242.3	(32.0)	109.6	77.0
53	Distribution		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Customer Care		1,449.3	1,443.0	(6.2)	1,593.2	1,615.4	22.2	1,677.6	1,691.2	13.6	1,625.4	1,691.2
55	Total		1,723.9	1,715.8	(8.1)	1,838.6	1,854.1	15.6	1,951.8	1,933.5	(18.3)	1,735.1	1,768.2
	Items Subject to HDA												
56	Heritage Energy	Line 28	363.8	354.4	(9.3)	341.5	309.0	(32.5)	349.0	299.3	(49.7)	350.9	350.8
57	Less: F15-F19 Water Rentals (Waneta 1/3)		(6.8)	(7.0)	(0.1)	(6.4)	(6.5)	(0.1)	(6.3)	(6.7)	(0.4)	0.0	0.0
58	Market Electricity Purchases	Line 34	8.6	3.4	(5.2)	30.2	3.7	(26.6)	35.9	89.1	53.2	40.0	18.2
59	Surplus Sales	Line 35	(118.1)	(132.8)	(14.6)	(150.4)	(139.4)	11.0	(129.2)	(115.0)	14.2	(97.1)	(111.4)
60	Domestic Transmission - Export	Line 37	31.8	28.3	(3.5)	35.4	25.2	(10.2)	29.9	18.5	(11.4)	17.4	21.0
61	Costs in Operating/Amortization		12.3	12.2	(0.1)	12.4	12.2	(0.2)	12.9	12.2	(0.7)	12.3	12.3
62	Notional Water Rentals		(1.9)	0.8	2.7	(1.7)	(3.7)	(2.0)	0.7	3.5	2.8	1.3	0.7
63	Skagit and Ancillary Revenue	14.0 L18	(12.6)	(13.0)	(0.5)	(12.0)	(11.9)	0.1	(12.1)	(28.6)	(16.5)	(28.6)	(28.7)
64	Deferred Operating HDA	5.0 L50	0.0	(0.1)	(0.1)	0.0	0.3	0.3	0.0	0.9	0.9	0.0	0.0
65	Other		28.2	27.9	(0.3)	36.5	36.3	(0.2)	36.2	36.2	(0.0)	31.5	31.2
66	Total		305.3	274.3	(31.0)	285.4	225.1	(60.4)	317.1	309.6	(7.5)	327.7	294.2
67	**Total System Inflow (% of Normal)**		98%	101%	3%	100%	98%	(2%)	100%	88%	(12%)	100%	100%

Cost of Energy
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Items Subject to NHDA												
68	Non-Heritage Cost of Energy	Line 33	1,269.6	1,249.7	(19.9)	1,407.2	1,351.1	(56.0)	1,476.5	1,365.1	(111.5)	1,576.3	1,641.1
69	Add: F15-F19 Water Rentals (Wane	Line 57	6.8	7.0	0.1	6.4	6.5	0.1	6.3	6.7	0.4	0.0	0.0
70	Less: Water Rentals (Waneta 2/3)	Line 32	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(2.4)	(2.4)	(3.5)	(3.7)
71	Net Purchases (Sales) from Powere	Line 36	(6.5)	2.3	8.8	(6.0)	(10.9)	(4.9)	0.7	16.4	15.6	(0.5)	0.5
72	Commodity Risk		0.0	(0.2)	(0.2)	0.0	(1.0)	(1.0)	0.0	0.0	0.0	0.0	0.0
73	Notional Water Rental	Line 62	1.9	(0.8)	(2.7)	1.7	3.7	2.0	(0.7)	(3.5)	(2.8)	(1.3)	(0.7)
74	Revenue Variance		0.0	1.3	1.3	0.0	(13.5)	(13.5)	0.0	24.0	24.0	0.0	0.0
75	Deferred Operating NHDA	5.0 L51	0.0	(8.9)	(8.9)	0.0	(35.6)	(35.58)	0.0	(0.5)	(0.5)	0.0	0.0
76	Deferred Amortization NHDA	7.0 L14	0.0	(3.3)	(3.3)	0.0	(14.0)	(14.0)	0.0	0.0	0.0	0.0	0.0
77	Deferred Taxes NHDA	6.0 L21	0.0	(0.4)	(0.4)	0.0	(1.9)	(1.9)	0.0	0.0	0.0	0.0	0.0
78	Deferred Provision NHDA	5.0 L101	0.0	0.0	0.0	0.0	1.6	1.6	0.0	0.0	0.0	0.0	0.0
79	Other		0.0	7.9	7.9	0.0	1.2	1.2	0.0	3.3	3.3	0.0	0.0
80	Total		1,271.9	1,254.7	(17.2)	1,409.3	1,287.3	(122.0)	1,482.9	1,409.0	(73.9)	1,571.0	1,637.2
	IPP Summary												
81	IPP Costs in Non-Heritage COE	Line 29	1,234.4	1,213.1	(21.3)	1,369.7	1,311.6	(58.1)	1,439.3	1,326.6	(112.7)	1,538.5	1,601.1
	Existing Capital Leases												
82	Operating Costs	5.7 L8	28.2	28.2	0.0	63.6	63.6	0.0	54.3	54.3	0.0	0.0	0.0
83	Taxes	6.0 L10	2.6	2.6	0.0	4.2	4.2	0.0	2.5	2.5	0.0	0.0	0.0
84	Amortization	7.0 L11	17.0	17.0	0.0	29.4	29.4	0.0	22.8	22.8	(0.0)	30.2	30.2
85	Finance Charges	8.0 L15	25.1	25.1	0.0	44.7	44.7	0.0	42.4	42.4	0.0	4.2	2.8
86	Total		72.9	72.9	0.0	141.8	141.8	0.0	122.1	122.1	(0.0)	34.4	33.0
87	Transfers to Deferral & Regulatory Accounts		0.0	(18.4)	(18.4)	0.0	(79.4)	(79.4)	0.0	(0.4)	(0.4)	0.0	0.0
88	Total Costs in Revenue Requirement		1,307.3	1,267.6	(39.7)	1,511.5	1,374.0	(137.5)	1,561.4	1,448.2	(113.1)	1,572.9	1,634.1
89	Total Payments to IPPs		1,312.5	1,274.7	(37.8)	1,509.9	1,381.7	(128.3)	1,547.9	1,434.3	(113.5)	1,573.2	1,634.3
90	Difference	L88 - L89	(5.2)	(7.2)	(1.9)	1.6	(7.6)	(9.2)	13.5	13.9	0.4	(0.3)	(0.2)
	IPP Capital Leases												
	Gross Assets in Service												
91	Opening Balance		388.2	388.2	0.0	858.2	388.2	(470.0)	858.2	694.7	(163.5)	694.7	364.8
92	Capital Additions		470.0	0.0	(470.0)	0.0	470.0	470.0	0.0	0.0	0.0	364.8	0.0
93	Retirements & Transfers		0.0	0.0	0.0	0.0	(163.5)	(163.5)	0.0	0.0	0.0	(694.7)	0.0
94	Closing Balance		858.2	388.2	(470.0)	858.2	694.7	(163.5)	858.2	694.7	(163.5)	364.8	364.8
	Accumulated Amortization												
95	Opening Balance		186.9	186.9	0.0	203.9	200.6	(3.3)	233.3	54.1	(179.1)	77.0	301.9
96	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	194.8	0.0
97	Amortization		17.0	13.7	(3.3)	29.4	15.4	(14.0)	22.8	22.8	0.0	30.2	30.2
98	Retirements & Transfers		0.0	0.0	0.0	0.0	(161.8)	(161.8)	0.0	0.0	0.0	0.0	0.0
99	Closing Balance		203.9	200.6	(3.3)	233.3	54.1	(179.1)	256.1	77.0	(179.1)	301.9	332.1
100	**Net Capital Leases (Year-End)**		654.3	187.6	(466.7)	624.9	640.6	15.7	602.1	617.8	15.7	62.9	32.7

Operating Costs and Provisions - Total Company
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Operating Costs by Business Group												
1	Integrated Planning	5.1 L8	271.3	284.8	13.5	269.4	283.8	14.4	270.1	279.3	9.2	290.8	293.0
2	Capital Infrastructure Project Delivery	5.2 L6	79.7	79.2	(0.5)	81.1	79.9	(1.2)	81.9	82.9	1.0	80.1	81.1
3	Operations	5.3 L9	206.1	204.2	(1.9)	208.2	206.7	(1.5)	216.2	214.5	(1.7)	237.3	240.1
4	Safety	5.4 L6	54.6	55.9	1.4	54.6	53.3	(1.3)	54.9	54.8	(0.2)	56.8	57.5
5	Finance, Technology, Supply Chain	5.5 L5	263.3	253.8	(9.5)	264.4	246.7	(17.7)	265.0	258.5	(6.5)	262.6	264.8
6	People, Customer, Corporate Affairs	5.6 L9	124.3	115.2	(9.1)	121.8	116.8	(5.1)	122.5	112.9	(9.6)	110.6	111.9
7	Other	5.7 L6	(252.7)	(256.6)	(3.9)	(252.2)	(244.0)	8.2	(251.6)	(233.4)	18.1	(260.2)	(260.5)
8	F17-F19 RRA Compliance Filing Adjustment		10.1	0.0	(10.1)	10.2	0.0	(10.2)	10.4	0.0	(10.4)	0.0	0.0
9	**Base Operating Costs**		756.6	736.6	(20.0)	757.5	743.1	(14.4)	769.5	769.5	(0.0)	777.9	787.8
10	IFRS Ineligible Capitalized Costs		102.9	102.9	0.0	125.3	125.3	0.0	147.7	147.7	0.0	170.1	192.5
11	Independent Power Producer Capital Leases		28.2	28.2	0.0	63.6	63.6	0.0	54.3	54.3	0.0	0.0	0.0
12	Waneta 2/3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8	3.8	5.7	5.9
13	Customer Crisis Fund		0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	4.0	5.3	5.3
14	**Total Base Operating Costs Adjustment**		131.0	131.0	0.0	188.8	188.8	0.0	202.0	209.8	7.8	181.1	203.6
15	**Net Operating Costs**	L9+L14	887.7	867.6	(20.0)	946.3	931.9	(14.4)	971.5	979.3	7.8	959.0	991.4
	Operating Costs by Resource												
16	Labour (excl Non-Current PEB)		489.3	487.8	(1.5)	499.3	522.2	22.8	509.1	557.5	48.4	575.9	586.1
17	Services - ABSU		48.7	48.1	(0.7)	48.0	41.9	(6.1)	49.3	3.5	(45.8)	0.0	0.0
18	Services - Other		446.4	419.3	(27.1)	477.1	434.2	(42.9)	461.5	473.0	11.5	423.2	421.5
19	Materials		40.7	47.9	7.2	40.6	48.2	7.6	40.6	46.4	5.8	46.2	46.2
20	Buildings & Equipment		58.8	67.4	8.6	58.8	67.2	8.4	58.9	60.7	1.7	51.4	51.5
21	Capitalized Overhead		(180.2)	(179.0)	1.2	(158.6)	(158.6)	(0.1)	(136.9)	(137.6)	(0.7)	(115.8)	(93.8)
22	External Recoveries		(26.2)	(23.9)	2.3	(29.2)	(23.1)	6.1	(21.5)	(24.2)	(2.7)	(22.1)	(20.1)
23	F17-F19 RRA Compliance Filing Adjustme	Line 8	10.1	0.0	(10.1)	10.2	0.0	(10.2)	10.4	0.0	(10.4)	0.0	0.0
24	Net Operating Costs		887.7	867.6	(20.0)	946.3	931.9	(14.4)	971.5	979.3	7.8	959.0	991.4
	Regulatory Account Recoveries - Operating Costs												
25	First Nation Costs		33.8	32.4	(1.3)	40.2	38.7	(1.5)	39.0	40.4	1.4	34.7	33.6
26	Storm Restoration		10.8	10.8	0.0	10.4	10.4	(0.0)	10.0	10.0	0.0	20.1	19.4
27	Capital Project Investigation		4.8	4.8	0.0	4.8	4.8	0.0	4.8	4.8	0.0	5.2	5.2
28	Smart Metering & Infrastructure		32.5	32.6	0.1	31.7	31.8	0.1	31.0	31.0	0.0	29.6	28.6
29	Home Purchase Offer Plan		0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Minimum Reconnection Charge		0.5	0.9	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	Non-Current Pension Cost		57.9	59.3	1.4	57.9	57.9	0.0	57.9	57.9	0.0	16.0	16.0
32	PEB Current Pension Costs		5.7	0.0	(5.7)	5.7	5.7	0.0	5.7	5.7	0.0	(1.2)	(1.2)
33	PEB CPC - F17-F19 RRA Compliance Filing Adjustment		0.0	0.0	0.0	0.0	4.3	4.3	0.0	0.0	0.0	0.0	0.0
34	IFRS PP&E		23.2	23.2	(0.0)	26.0	26.0	(0.0)	28.2	28.2	0.0	29.9	31.0
35	IFRS Pension		38.2	38.2	(0.0)	38.2	38.2	(0.0)	38.2	38.2	0.0	38.2	38.2
36	Total		207.5	202.3	(5.2)	214.9	217.9	3.0	214.9	216.3	1.4	172.5	170.9
37	**Total Current Operating Costs**	L15+L36	1,095.1	1,069.9	(25.2)	1,161.2	1,149.8	(11.4)	1,186.4	1,195.7	9.2	1,131.5	1,162.3

Operating Costs and Provisions - Total Company
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Current Operating Costs by Business Group												
38	Integrated Planning	Line 1	271.3	284.8	13.5	269.4	283.8	14.4	270.1	279.3	9.2	290.8	293.0
39	Capital Infrastructure Project Delivery	L2+L25+L27	118.3	116.5	(1.8)	126.1	123.4	(2.7)	125.8	128.2	2.4	119.9	120.0
40	Operations	L3+L12+L26	217.0	215.0	(1.9)	218.6	217.1	(1.5)	226.2	228.4	2.2	263.2	265.4
41	Safety	Line 4	54.6	55.9	1.4	54.6	53.3	(1.3)	54.9	54.8	(0.2)	56.8	57.5
42	Finance, Technology, Supply Chain	Line 5	263.3	253.8	(9.5)	264.4	246.7	(17.7)	265.0	258.5	(6.5)	262.6	264.8
43	People, Customer, Corporate Affairs	L6+L13+L28	156.8	147.9	(9.0)	153.5	148.6	(4.9)	153.5	147.9	(5.6)	145.4	145.8
44	Other	L7+L10+L11+L29+L30+L34+L35	(59.7)	(63.3)	(3.6)	0.9	9.0	8.2	16.9	35.1	18.1	(22.0)	1.2
45	Non-Current PEB - Pension	Line 31	57.9	59.3	1.4	57.9	57.9	0.0	57.9	57.9	0.0	16.0	16.0
46	PEB Current Pension Costs	Line 32	5.7	0.0	(5.7)	5.7	5.7	0.0	5.7	5.7	0.0	(1.2)	(1.2)
47	PEB CPC - F17-F19 RRA Compliance Filing Adjustment	Line 33	0.0	0.0	0.0	0.0	4.3	4.3	0.0	0.0	0.0	0.0	0.0
48	F17-F19 RRA Compliance Filing Adjustme	Line 8	10.1	0.0	(10.1)	10.2	0.0	(10.2)	10.4	0.0	(10.4)	0.0	0.0
49	Total		1,095.1	1,069.9	(25.2)	1,161.2	1,149.8	(11.4)	1,186.4	1,195.7	9.2	1,131.5	1,162.3
	Deferral Account Additions												
50	Transfers to HDA		0.0	(0.1)	(0.1)	0.0	0.3	0.3	0.0	0.9	0.9	0.0	0.0
51	Transfers to NHDA		0.0	(8.9)	(8.9)	0.0	(35.6)	(35.6)	0.0	(0.5)	(0.5)	0.0	0.0
52	Total		0.0	(9.0)	(9.0)	0.0	(35.3)	(35.3)	0.0	0.5	0.5	0.0	0.0
	Regulatory Account Additions												
53	Demand-Side Management		113.7	97.4	(16.3)	119.5	82.5	(36.9)	127.9	124.2	(3.7)	109.1	125.9
54	First Nations Costs		5.6	4.0	(1.6)	3.7	2.0	(1.7)	2.8	3.4	0.7	3.2	2.4
55	Site C Project		0.0	0.0	0.0	0.0	0.3	0.3	0.0	0.3	0.3	0.3	0.3
56	Storm Restoration		0.0	18.6	18.6	0.0	16.2	16.2	0.0	0.0	0.0	0.0	0.0
57	Smart Metering & Infrastructure		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
58	IFRS Capitalized Overhead		112.0	112.0	0.0	89.6	89.6	0.0	67.2	67.2	0.0	44.8	22.4
59	PEB Current Pension Costs		0.0	10.1	10.1	0.0	(2.5)	(2.5)	0.0	0.0	0.0	0.0	0.0
60	PEB CPC - F17-F19 RRA Compliance Filing Adjustment		0.0	0.0	0.0	0.0	(10.1)	(10.1)	0.0	0.0	0.0	0.0	0.0
61	Real Property Sales		0.0	0.8	0.8	0.0	1.6	1.6	0.0	0.0	0.0	0.0	0.0
62	Customer Crisis Fund		0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.3	0.3	(0.3)	(0.3)
63	Total		231.3	242.9	11.6	212.7	179.8	(32.9)	197.9	195.5	(2.4)	157.1	150.9
64	**Total Gross Operating Costs**	L15+L52+L63	1,119.0	1,101.5	(17.4)	1,159.0	1,076.4	(82.6)	1,169.4	1,175.3	5.9	1,116.1	1,142.3

Operating Costs and Provisions - Total Company
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Net Provisions & Other												
65	Integrated Planning		34.9	46.6	11.8	35.9	58.5	22.6	35.6	35.6	0.0	40.5	42.9
66	Capital Infrastructure Project Delivery		0.0	(0.8)	(0.8)	0.0	2.4	2.4	0.0	0.0	0.0	0.0	0.0
67	Operations		3.7	2.9	(0.9)	3.8	3.9	0.1	3.6	3.6	0.0	6.5	7.2
68	Safety		0.0	0.0	0.0	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.0
69	Finance, Technology, Supply Chain		0.0	7.8	7.8	0.0	7.8	7.8	0.0	0.0	0.0	0.0	0.0
70	People, Customer, Corporate Affairs		0.0	0.5	0.5	0.0	4.0	4.0	0.0	0.0	0.0	0.0	0.0
71	Other		5.3	5.0	(0.3)	5.5	12.5	7.0	5.9	5.8	(0.1)	12.2	11.9
	Dismantling Expense												
72	Integrated Planning		26.0	26.0	0.0	24.0	24.0	0.0	24.0	24.0	0.0	33.0	34.8
73	Capital Infrastructure Project Delivery		1.8	1.8	0.0	3.7	3.7	0.0	0.7	0.7	0.0	1.5	0.3
74	Operations		3.1	3.1	0.0	8.0	8.0	0.0	6.0	6.0	0.0	32.4	7.8
75	Finance, Technology, Supply Chain		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2
76	Real Property Sales		(10.0)	(10.0)	0.0	(10.0)	(10.0)	0.0	(10.0)	(10.0)	0.0	(10.0)	(10.0)
77	Total		64.7	83.0	18.3	71.0	115.2	44.2	65.7	65.6	(0.1)	116.2	95.1
	Regulatory Account Recoveries - Provisions & Other												
	PCB Remediation												
78	Integrated Planning		16.8	16.8	0.0	15.5	15.5	(0.0)	14.7	14.7	0.0	22.9	23.3
79	Operations		1.4	1.4	(0.0)	3.2	3.2	(0.0)	0.5	0.5	0.0	0.9	0.7
80	Other		0.1	0.1	(0.0)	0.2	0.2	(0.0)	0.0	0.0	0.0	0.0	0.0
	Asbestos Remediation												
81	Integrated Planning		22.5	22.5	0.0	12.7	12.7	0.0	10.5	13.2	2.7	7.9	7.0
82	Operations		1.3	1.3	0.0	2.0	2.0	0.0	2.0	2.0	(0.1)	2.5	0.9
83	Other		0.6	0.6	0.0	1.8	1.8	0.0	2.7	0.1	(2.6)	0.2	0.0
	Dismantling Cost												
84	Integrated Planning		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.7	25.7
85	Safety		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
86	Finance, Technology, Supply Chain		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2
87	Rock Bay Remediation		(3.8)	(3.8)	0.0	(3.2)	(3.2)	0.0	0.0	0.0	0.0	(10.8)	(10.4)
88	Arrow Water Divestiture Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
89	Arrow Water Provision		1.8	0.3	(1.5)	0.3	1.8	1.5	0.3	0.3	(0.0)	0.3	0.3
90	Rate Smoothing		(216.5)	(201.2)	15.2	(311.0)	(326.2)	(15.2)	(321.4)	814.9	1,136.3	0.0	0.0
91	Total		(175.7)	(162.0)	13.7	(278.5)	(292.2)	(13.8)	(290.5)	845.8	1,136.3	50.9	47.7
92	**Total Current Provisions & Other**	L77 + L91	(111.0)	(79.0)	32.0	(207.5)	(177.0)	30.4	(224.8)	911.4	1,136.3	167.1	142.8
	Current Provisions & Other by Business Group												
93	Integrated Planning	L65+L72+L78+L81+L84	100.2	112.0	11.8	88.2	110.8	22.6	84.8	87.5	2.7	130.9	133.7
94	Capital Infrastructure Project Delivery	L66+L73+L76	(8.2)	(9.0)	(0.8)	(6.3)	(3.9)	2.4	(9.4)	(9.4)	0.0	(8.5)	(9.8)
95	Operations	L67 + L74 + L79 + L82 + L88 + L89	11.4	9.0	(2.4)	17.3	18.9	1.5	12.5	12.4	(0.1)	42.7	17.0
96	Safety	L68+L85	0.0	0.0	0.0	0.0	0.3	0.3	0.0	0.0	0.0	0.1	0.1
97	Finance, Technology, Supply Chain	L69+L75+L86	0.0	7.8	7.8	0.0	7.8	7.8	0.0	0.0	0.0	0.3	0.3
98	People, Customer, Corporate Affairs	L70	0.0	0.5	0.5	0.0	4.0	4.0	0.0	0.0	0.0	0.0	0.0
99	Other	L71 + L80 + L83 + L87 + L90	(214.4)	(199.4)	15.0	(306.7)	(314.9)	(8.2)	(312.7)	820.9	1,133.7	1.6	1.6
100	Total		(111.0)	(79.0)	32.0	(207.5)	(177.0)	30.4	(224.8)	911.4	1,136.3	167.1	142.8

Operating Costs and Provisions - Total Company
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Deferral Account Additions - Provisions & Other												
101	Transfers to NHDA		0.0	0.0	0.0	0.0	1.6	1.6	0.0	0.0	0.0	0.0	0.0
102	Total		0.0	0.0	0.0	0.0	1.6	1.6	0.0	0.0	0.0	0.0	0.0
	Regulatory Account Additions - Provisions & Other												
103	First Nations Provisions		(5.3)	(3.3)	2.0	0.0	0.9	0.9	0.0	2.4	2.4	0.0	0.0
104	Environmental Provisions		0.0	(28.0)	(28.0)	0.0	(4.0)	(4.0)	0.0	(4.3)	(4.3)	0.0	0.0
105	Arrow Water Provision		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
106	Smart Metering & Infrastructure DSMD Write-Off		0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0
107	Real Property Sales		6.5	9.0	2.5	(10.0)	6.8	16.8	(14.0)	4.8	18.8	(8.1)	(8.1)
108	Dismantling Expense		0.0	2.9	2.9	0.0	31.7	31.7	0.0	13.9	13.9	0.0	0.0
109	Total		1.2	(19.5)	(20.7)	(10.0)	35.4	45.4	(14.0)	16.7	30.7	(8.1)	(8.1)
110	**Total Gross Provisions & Other**	L77 + L102 + L109	66.0	63.6	(2.4)	61.0	152.3	91.2	51.7	82.3	30.6	108.2	87.0
	Total Current Operating and Provisions & Other												
111	Integrated Planning	L38 + L93	371.5	396.7	25.3	357.6	394.6	37.0	354.8	366.7	11.9	421.7	426.7
112	Capital Infrastructure Project Delivery	L39 + L94	110.0	107.5	(2.6)	119.8	119.5	(0.3)	116.4	118.9	2.4	111.4	110.2
113	Operations	L40 + L95	228.3	224.0	(4.3)	235.9	236.0	0.0	238.7	240.8	2.1	305.9	282.3
114	Safety	L41 + L96	54.6	56.0	1.4	54.6	53.6	(1.0)	54.9	54.8	(0.2)	56.9	57.6
115	Finance, Technology, Supply Chain	L42 + L97	263.3	261.6	(1.7)	264.4	254.5	(9.9)	265.0	258.5	(6.5)	263.0	265.1
116	People, Customer, Corporate Affairs	L43 + L98	156.8	148.4	(8.4)	153.5	152.6	(0.9)	153.5	147.9	(5.6)	145.4	145.8
117	Other	L44 + L99	(274.0)	(262.6)	11.4	(305.8)	(305.9)	(0.1)	(295.8)	856.0	1,151.8	(20.4)	2.8
118	Non-Current PEB - Pension	Line 45	57.9	59.3	1.4	57.9	57.9	0.0	57.9	57.9	0.0	16.0	16.0
119	PEB Current Pension Costs	Line 46	5.7	0.0	(5.7)	5.7	5.7	0.0	5.7	5.7	0.0	(1.2)	(1.2)
120	PEB CPC - F17-F19 RRA Compliance Filing Adjustment	Line 47	0.0	0.0	0.0	0.0	4.3	4.3	0.0	0.0	0.0	0.0	0.0
121	F17-F19 RRA Compliance Filing Adjustment	Line 48	10.1	0.0	(10.1)	10.2	0.0	(10.2)	10.4	0.0	(10.4)	0.0	0.0
122	**Total Current Operating and Provisions & Other**	L49 + L100	984.2	990.9	6.8	953.8	972.8	19.0	961.6	2,107.1	1,145.5	1,298.6	1,305.2
123	**Total Gross Operating and Provisions & Other**	L64 + L110	1,185.0	1,165.1	(19.9)	1,220.0	1,228.7	8.7	1,221.0	1,257.5	36.5	1,224.2	1,229.3

Operating Costs and Provisions - Total Company
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Operating Costs and Provisions & Other Continuity												
124	**Base Operating Costs**	Line 9	756.6	736.6	(20.0)	757.5	743.1	(14.4)	769.5	769.5	(0.0)	777.9	787.8
125	Base Operating Costs Adjustments	Line 14	131.0	131.0	0.0	188.8	188.8	0.0	202.0	209.8	7.8	181.1	203.6
126	**Net Operating Costs**	Line 15	**887.7**	**867.6**	**(20.0)**	**946.3**	**931.9**	**(14.4)**	**971.5**	**979.3**	**7.8**	**959.0**	**991.4**
127	Provisions & Other	Line 77	64.7	83.0	18.3	71.0	115.2	44.2	65.7	65.6	(0.1)	116.2	95.1
128	Operating Costs - Deferral Account Additions and Regulatory Account Additions	L52 + L63	231.3	233.9	2.6	212.7	144.5	(68.2)	197.9	195.9	(2.0)	157.1	150.9
129	Provisions & Other - Deferral Account Additions and Regulatory Account Additions	L102 + L109	1.2	(19.5)	(20.7)	(10.0)	37.1	47.1	(14.0)	16.7	30.7	(8.1)	(8.1)
130	**Gross Operating Costs and Provisions & Other**	Line 123	**1,185.0**	**1,165.1**	**(19.9)**	**1,220.0**	**1,228.7**	**8.7**	**1,221.0**	**1,257.5**	**36.5**	**1,224.2**	**1,229.3**
131	Reverse Operating Costs - Deferral Account Additions and Regulatory Account Additions	Line 128	(231.3)	(233.9)	(2.6)	(212.7)	(144.5)	68.2	(197.9)	(195.9)	2.0	(157.1)	(150.9)
132	Reverse Provisions & Other - Deferral Account Additions and Regulatory Account Additions	Line 129	(1.2)	19.5	20.7	10.0	(37.1)	(47.1)	14.0	(16.7)	(30.7)	8.1	8.1
133	Operating Costs - Regulatory Account Recoveries	Line 36	207.5	202.3	(5.2)	214.9	217.9	3.0	214.9	216.3	1.4	172.5	170.9
134	Provisions & Other - Regulatory Account Recoveries	Line 91	(175.7)	(162.0)	13.7	(278.5)	(292.2)	(13.8)	(290.5)	845.8	1,136.3	50.9	47.7
135	**Current Operating Costs and Provisions & Other**	Line 122	**984.2**	**990.9**	**6.8**	**953.8**	**972.8**	**19.0**	**961.6**	**2,107.1**	**1,145.5**	**1,298.6**	**1,305.2**

Operating Costs and Provisions - Total Company
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Operating Costs Continuity												
136	**Base Operating Costs**	Line 9	756.6	736.6	(20.0)	757.5	743.1	(14.4)	769.5	769.5	(0.0)	777.9	787.8
137	Base Operating Costs Adjustments	Line 14	131.0	131.0	0.0	188.8	188.8	0.0	202.0	209.8	7.8	181.1	203.6
138	**Net Operating Costs**	Line 15	**887.7**	**867.6**	**(20.0)**	**946.3**	**931.9**	**(14.4)**	**971.5**	**979.3**	**7.8**	**959.0**	**991.4**
139	Operating Costs - Deferral Account Additions and Regulatory Account Additions	L52 + L63	231.3	233.9	2.6	212.7	144.5	(68.2)	197.9	195.9	(2.0)	157.1	150.9
140	**Gross Operating Costs**	Line 64	**1,119.0**	**1,101.5**	**(17.4)**	**1,159.0**	**1,076.4**	**(82.6)**	**1,169.4**	**1,175.3**	**5.9**	**1,116.1**	**1,142.3**
141	Reverse Operating Costs - Deferral Account Additions and Regulatory Account Additions	Line 128	(231.3)	(233.9)	(2.6)	(212.7)	(144.5)	68.2	(197.9)	(195.9)	2.0	(157.1)	(150.9)
142	Operating Costs - Regulatory Account Recoveries	Line 36	207.5	202.3	(5.2)	214.9	217.9	3.0	214.9	216.3	1.4	172.5	170.9
143	**Current Operating Costs**	Line 37	**1,095.1**	**1,069.9**	**(25.2)**	**1,161.2**	**1,149.8**	**(11.4)**	**1,186.4**	**1,195.7**	**9.2**	**1,131.5**	**1,162.3**
	Provisions & Other Continuity												
144	Provision & Other	Line 77	64.7	83.0	18.3	71.0	115.2	44.2	65.7	65.6	(0.1)	116.2	95.1
145	Provision & Other - Deferral Account Additions and Regulatory Account Additions	L102 + L109	1.2	(19.5)	(20.7)	(10.0)	37.1	47.1	(14.0)	16.7	30.7	(8.1)	(8.1)
146	**Gross Provisions & Other**	Line 110	**66.0**	**63.6**	**(2.4)**	**61.0**	**152.3**	**91.2**	**51.7**	**82.3**	**30.6**	**108.2**	**87.0**
147	Reverse Provisions & Other - Deferral Account Additions and Regulatory Account Additions	Line 145	(1.2)	19.5	20.7	10.0	(37.1)	(47.1)	14.0	(16.7)	(30.7)	8.1	8.1
148													
149	Provisions & Other - Regulatory Account Recoveries	Line 91	(175.7)	(162.0)	13.7	(278.5)	(292.2)	(13.8)	(290.5)	845.8	1,136.3	50.9	47.7
150	**Current Provisions & Other**	Line 100	**(111.0)**	**(79.0)**	**32.0**	**(207.5)**	**(177.0)**	**30.4**	**(224.8)**	**911.4**	**1,136.3**	**167.1**	**142.8**

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Gross Operating Costs Including Regulatory												
1	Labour (excl Non-Current PEB)	L99 + L108	511.2	524.9	13.7	521.1	537.2	16.1	531.4	579.4	48.0	600.1	610.1
2	Services - ABSU	L100 + L109	49.1	48.9	(0.2)	48.4	42.3	(6.1)	49.6	3.5	(46.1)	0.0	0.0
3	Services - Other	L101 + L110	542.8	502.2	(40.6)	618.6	472.7	(146.0)	541.9	579.0	37.1	510.3	525.1
4	Materials	L102 + L111	41.1	48.7	7.6	41.0	48.8	7.8	40.9	46.6	5.7	46.5	46.5
5	Buildings & Equipment	L103 + L112	59.0	67.7	8.7	59.0	67.6	8.6	59.2	61.2	2.1	52.2	52.1
6	F17-F19 RRA Compliance Filing Adjustment	L104 + L114	10.1	0.0	(10.1)	(30.9)	0.0	30.9	37.6	0.0	(37.6)	0.0	0.0
			1,213.3	1,192.4	(20.9)	1,257.2	1,168.6	(88.6)	1,260.6	1,269.8	9.2	1,209.1	1,233.8
	Less:												
7	Eligible Capital Overhead	L105 + L116	(68.2)	(67.0)	1.2	(69.0)	(69.0)	(0.1)	(69.7)	(70.4)	(0.7)	(71.0)	(71.4)
8	External Recoveries	L106 + L113	(26.2)	(23.9)	2.3	(29.2)	(23.1)	6.1	(21.5)	(24.2)	(2.7)	(22.1)	(20.1)
9	**Total Gross Operating Costs Including**	5.0 L64	**1,119.0**	**1,101.5**	**(17.4)**	**1,159.0**	**1,076.4**	**(82.6)**	**1,169.4**	**1,175.3**	**5.9**	**1,116.1**	**1,142.3**
10	**Total Gross Provision & Other Including**	5.0 L110	66.0	63.6	(2.4)	61.0	152.3	91.2	51.7	82.3	30.6	108.2	87.0
11	**Total Gross Operating Cost and Provision &**	5.0 L123 (or 3.0 L13)	**1,185.0**	**1,165.1**	**(19.9)**	**1,220.0**	**1,228.7**	**8.7**	**1,221.0**	**1,257.5**	**36.5**	**1,224.3**	**1,229.3**
	Less Regulatory Account Additions												
	Demand-Side Management												
12	Labour		**(21.4)**	**(20.8)**	0.5	**(21.3)**	**(20.9)**	0.3	**(21.8)**	**(20.9)**	0.9	**(23.3)**	**(23.2)**
13	Services - ABSU		**(0.3)**	**(0.8)**	(0.4)	**(0.3)**	**(0.4)**	(0.0)	**(0.3)**	**(0.0)**	0.2	**0.0**	**0.0**
14	Services - Other		**(91.4)**	**(75.2)**	16.2	**(138.4)**	**(60.6)**	77.7	**(78.1)**	**(102.5)**	(24.4)	**(84.8)**	**(101.9)**
15	Materials		**(0.4)**	**(0.3)**	0.1	**(0.4)**	**(0.2)**	0.1	**(0.4)**	**(0.2)**	0.1	**(0.3)**	**(0.3)**
16	Buildings & Equipment		**(0.2)**	**(0.4)**	(0.1)	**(0.2)**	**(0.4)**	(0.1)	**(0.2)**	**(0.6)**	(0.3)	**(0.8)**	**(0.6)**
17	F17-F19 RRA Compliance Filing Adjustment		**0.0**	**0.0**		**41.1**	**0.0**	(41.1)	**(27.2)**	**0.0**	27.2	**0.0**	**0.0**
	First Nations Costs												
18	Labour		**(0.5)**	**(1.0)**	(0.5)	**(0.5)**	**(0.9)**	(0.4)	**(0.5)**	**(1.0)**	(0.5)	**(0.9)**	**(0.8)**
19	Services - ABSU		**(0.0)**	**(0.1)**	(0.0)	**(0.0)**	**(0.0)**	0.0	**(0.0)**	**0.0**	0.0	**0.0**	**0.0**
20	Services - Other		**(5.0)**	**(2.9)**	2.2	**(3.1)**	**(1.1)**	2.0	**(2.2)**	**(2.4)**	(0.2)	**(2.3)**	**(1.6)**
21	Materials		**0.0**	**(0.0)**	(0.0)	**0.0**	**(0.0)**	(0.0)	**0.0**	**(0.0)**	(0.0)	**0.0**	**0.0**
22	Buildings & Equipment		**0.0**	**(0.0)**	(0.0)	**0.0**	**(0.0)**	(0.0)	**0.0**	**0.0**	0.0	**0.0**	**0.0**
	Site C Project												
23	Labour		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**
24	Services - ABSU		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**
25	Services - Other		**0.0**	**0.0**	0.0	**0.0**	**(0.3)**	(0.3)	**0.0**	**(0.3)**	(0.3)	**(0.3)**	**(0.3)**
26	Materials		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**
27	Buildings & Equipment		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**
	Storm Restoration												
28	Labour		**0.0**	**(4.5)**	(4.5)	**0.0**	**(4.7)**	(4.7)	**0.0**	**0.0**	0.0	**0.0**	**0.0**
29	Services - ABSU		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**
30	Services - Other		**0.0**	**(13.6)**	(13.6)	**0.0**	**(11.1)**	(11.1)	**0.0**	**0.0**	0.0	**0.0**	**0.0**
31	Materials		**0.0**	**(0.5)**	(0.5)	**0.0**	**(0.3)**	(0.3)	**0.0**	**0.0**	0.0	**0.0**	**0.0**
32	Buildings & Equipment		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Gross Operating Costs Including Regulatory												
	Smart Metering & Infrastructure												
33	Labour		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	Services - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	External Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Pension Cost												
39	Labour		0.0	(10.1)	(10.1)	0.0	2.5	2.5	0.0	0.0	0.0	0.0	0.0
40	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Services - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	Materials		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
43	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Pension Cost - F17-F19 RRA Compliance Filing Adjustment												
44	Labour					0.0	10.1	10.1	0.0	0.0	0.0	0.0	0.0
45	Services - ABSU					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
46	Services - Other					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
47	Materials					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
48	Buildings & Equipment					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Real Property Sales												
49	Labour		0.0	(0.4)	(0.4)	0.0	(0.5)	(0.5)	0.0	0.0	0.0	0.0	0.0
50	Services - ABSU		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51	Services - Other		0.0	(0.4)	(0.4)	0.0	(1.1)	(1.1)	0.0	0.0	0.0	0.0	0.0
52	Materials		0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0
53	Buildings & Equipment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Customer Crisis Fund												
54	Labour					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
55	Services - ABSU					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
56	Services - Other					0.0	(0.1)	(0.1)	0.0	(0.3)	(0.3)	0.3	0.3
57	Materials					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
58	Buildings & Equipment					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
59	**IFRS Capitalized Overhead**	5.0 L58	(112.0)	(112.0)	0.0	(89.6)	(89.6)	0.0	(67.2)	(67.2)	0.0	(44.8)	(22.4)
60	**Total Regulatory Account Additions**	5.0 L63	(231.3)	(242.9)	(11.6)	(212.7)	(179.8)	32.9	(197.9)	(195.5)	2.4	(157.1)	(150.9)
	Less Deferred Provisions												
61	First Nations Provisions	5.0 L103	5.3	3.3	(2.0)	0.0	(0.9)	(0.9)	0.0	(2.4)	(2.4)	0.0	0.0
62	Environmental Provisions	5.0 L104	0.0	28.0	28.0	0.0	4.0	4.0	0.0	4.3	4.3	0.0	0.0
63	Arrow Water Provision	5.0 L105	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
64	Smart Metering & Infrastructure DSMD Write-Off	5.0 L106	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
65	Real Property Sales	5.0 L107	(6.5)	(9.0)	(2.5)	10.0	(6.8)	(16.8)	14.0	(4.8)	(18.8)	8.1	8.1
66	Dismantling Cost	5.0 L108	0.0	(2.9)	(2.9)	0.0	(31.7)	(31.7)	0.0	(13.9)	(13.9)	0.0	0.0
67	**Total Deferred Provisions**	5.0 L109	(1.2)	19.5	20.7	10.0	(35.4)	(45.4)	14.0	(16.7)	(30.7)	8.1	8.1
68	**Total Deferred Costs**	L60 + L67 (or 3.0 L16:L17)	(232.5)	(223.4)	9.1	(202.7)	(215.3)	(12.5)	(183.9)	(212.2)	(28.3)	(149.0)	(142.8)

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Gross Operating Costs Including Regulatory Less Deferral Account Additions												
	Transfers to HDA												
69	Labour		0.0	0.0	0.0	0.0	(0.1)	(0.1)	0.0	0.0	0.0	0.0	0.0
70	Services - Other		0.0	0.1	0.1	0.0	(0.2)	(0.2)	0.0	(0.9)	(0.9)	0.0	0.0
71	Materials		0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0
	Transfers to NHDA												
72	Labour		0.0	(0.1)	(0.1)	0.0	(0.4)	(0.4)	0.0	0.0	0.0	0.0	0.0
73	Services - Other		0.0	9.1	9.1	0.0	36.1	36.1	0.0	0.5	0.5	0.0	0.0
74	Materials		0.0	0.0	0.0	0.0	(0.1)	(0.1)	0.0	0.0	0.0	0.0	0.0
	Transfers to NHDA - Provisions & Other												
75	Provision & Other	5.0 L101				0.0	(1.6)	(1.6)	0.0	0.0	0.0	0.0	0.0
76	**Total Deferral Account Additions**	5.0 L52+L102 (or 3.0 L14:L15)	0.0	9.0	9.0	0.0	33.7	33.7	0.0	(0.5)	(0.5)	0.0	0.0
	Add Regulatory Account Recoveries												
77	First Nation Costs	5.0 L25	33.8	32.4	(1.3)	40.2	38.7	(1.5)	39.0	40.4	1.4	34.7	33.6
78	Storm Restoration	5.0 L26	10.8	10.8	0.0	10.4	10.4	(0.0)	10.0	10.0	0.0	20.1	19.4
79	Capital Project Investigation	5.0 L27	4.8	4.8	0.0	4.8	4.8	0.0	4.8	4.8	0.0	5.2	5.2
80	Smart Metering & Infrastructure	5.0 L28	32.5	32.6	0.1	31.7	31.8	0.1	31.0	31.0	0.0	29.6	28.6
81	Home Purchase Offer Plan	5.0 L29	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
82	Minimum Reconnection Charge	5.0 L30	0.5	0.9	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
83	Non-Current Pension Cost	5.0 L31	57.9	59.3	1.4	57.9	57.9	0.0	57.9	57.9	0.0	16.0	16.0
84	PEB Current Pension Costs	5.0 L32	5.7	0.0	(5.7)	5.7	5.7	0.0	5.7	5.7	0.0	(1.2)	(1.2)
85	PEB CPC - F17-F19 RRA Compliance Filing Adjustment	5.0 L33	0.0	0.0	0.0	0.0	4.3	4.3	0.0	0.0	0.0	0.0	0.0
86	IFRS PP&E	5.0 L34	23.2	23.2	(0.0)	26.0	26.0	(0.0)	28.2	28.2	0.0	29.9	31.0
87	IFRS Pension	5.0 L35	38.2	38.2	(0.0)	38.2	38.2	(0.0)	38.2	38.2	0.0	38.2	38.2
88	**Total Regulatory Account Recoveries (Operating Costs)**	5.0 L36	207.5	202.3	(5.2)	214.9	217.9	3.0	214.9	216.3	1.4	172.5	170.9
89	Remediation (PCB)	5.0 L78:L80	18.3	18.3	(0.0)	18.9	18.9	(0.0)	15.3	15.3	0.0	23.8	24.0
90	Remediation (Asbestos)	5.0 L81:L83	24.4	24.4	0.0	16.6	16.6	0.0	15.3	15.3	(0.0)	10.6	7.9
91	Dismantling Expense	5.0 L84:L86	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.9	25.9
92	Rock Bay Remediation	5.0 L87	(3.8)	(3.8)	0.0	(3.2)	(3.2)	0.0	0.0	0.0	0.0	(10.8)	(10.4)
93	Arrow Water Divestiture Costs	5.0 L88	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
94	Arrow Water Provision	5.0 L89	1.8	0.3	(1.5)	0.3	1.8	1.5	0.3	0.3	(0.0)	0.3	0.3
95	Rate Smoothing	5.0 L90	(216.5)	(201.2)	15.2	(311.0)	(326.2)	(15.2)	(321.4)	814.9	1,136.3	0.0	0.0
96	**Total Regulatory Account Recoveries (Provisions & Other)**	5.0 L91	(175.7)	(162.0)	13.7	(278.5)	(292.2)	(13.8)	(290.5)	845.8	1,136.3	50.9	47.7
97	**Total Regulatory Account Recoveries**	L88 + L96 (or 3.0 L19:L20)	31.7	40.3	8.5	(63.5)	(74.3)	(10.8)	(75.6)	1,062.2	1,137.7	223.3	218.6
98	**Total Current Operating Costs & Provisions &**	5.0 L122 (or 3.0 L21)	984.2	990.9	6.8	953.8	972.8	19.0	961.6	2,107.1	1,145.5	1,298.6	1,305.2

Operating Costs and Provisions - Total Company - Supplemental Schedule
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Gross Operating Costs Including Regulatory												
	SUMMARY OF OPERATING COSTS ABOVE												
	Operating Costs Before Deferrals												
99	Labour (excl Non-Current PEB)	5.0 L16	489.3	487.8	(1.5)	499.3	522.2	22.8	509.1	557.5	48.4	575.9	586.1
100	Services - ABSU	5.0 L17	48.7	48.1	(0.7)	48.0	41.9	(6.1)	49.3	3.5	(45.8)	0.0	0.0
101	Services - Other	5.0 L18	446.4	419.3	(27.1)	477.1	434.2	(42.9)	461.5	473.0	11.5	423.2	421.5
102	Materials	5.0 L19	40.7	47.9	7.2	40.6	48.2	7.6	40.6	46.4	5.8	46.2	46.2
103	Buildings & Equipment	5.0 L20	58.8	67.4	8.6	58.8	67.2	8.4	58.9	60.7	1.7	51.4	51.5
104	F17-F19 RRA Compliance Filing Adjustm	5.0 L23	10.1	0.0	(10.1)	10.2	0.0	(10.2)	10.4	0.0	(10.4)	0.0	0.0
	Less:												
105	Capital Overhead	5.0 L21	(180.2)	(179.0)	1.2	(158.6)	(158.6)	(0.1)	(136.9)	(137.6)	(0.7)	(115.8)	(93.8)
106	External Recoveries	5.0 L22	(26.2)	(23.9)	2.3	(29.2)	(23.1)	6.1	(21.5)	(24.2)	(2.7)	(22.1)	(20.1)
107	**Total Operating Costs Before Deferrals**	5.0 L24	**887.7**	**867.6**	**(20.0)**	**946.3**	**931.9**	**(14.4)**	**971.5**	**979.3**	**7.8**	**959.0**	**991.4**
	Deferred Operating Costs												
108	Labour (excl Non-Current PEB)	-(L12 + L18 + L23 + L28 + L33 + L39 + L44 + L49 + L54 + L69 + L72)	21.8	37.0	15.2	21.8	15.0	(6.7)	22.3	21.9	(0.3)	24.2	24.1
109	Services - ABSU	-(L13 + L19 + L24 + L29 + L34 + L40 + L45 + L50 + L55)	0.4	0.8	0.4	0.4	0.4	0.0	0.3	0.0	(0.3)	0.0	0.0
110	Services - Other	-(L14 + L20 + L25 + L30 + L35 + L41 + L46 + L51 + L56 + L70 + L73)	96.5	82.9	(13.5)	141.5	38.4	(103.0)	80.3	106.0	25.7	87.1	103.6
111	Materials	-(L15 + L21 + L26 + L31 + L36 + L42 + L47 + L52 + L58 + L71 + L74)	0.4	0.8	0.4	0.4	0.6	0.3	0.4	0.2	(0.1)	0.3	0.3
112	Buildings & Equipment	-(L16 + L22 + L27 + L32 + L37 + L43 + L48 + L53 + L58)	0.2	0.4	0.1	0.2	0.4	0.2	0.2	0.6	0.3	0.8	0.6
113	External Recoveries	- L38	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
114	F17-F19 RRA Compliance Filing Adjustm	-L17	0.0	0.0	0.0	(41.1)	0.0	41.1	27.2	0.0	(27.2)	0.0	0.0
115	**Total Deferred Operating Costs**		**119.3**	**121.9**	**2.6**	**123.1**	**54.9**	**(68.2)**	**130.7**	**128.7**	**(2.0)**	**112.3**	**128.5**
116	**IFRS Capitalized Overhead**	5.0 L58	112.0	112.0	0.0	89.6	89.6	0.0	67.2	67.2	0.0	44.8	22.4
117	**Total Operating Costs Including Deferrals**	Line 9	**1,119.0**	**1,101.5**	**(17.4)**	**1,159.0**	**1,076.4**	**(82.6)**	**1,169.4**	**1,175.3**	**5.9**	**1,116.1**	**1,142.3**
118	**Provisions & Other**	Line 10	66.0	63.6	(2.4)	61.0	152.3	91.2	51.7	82.3	30.6	108.2	87.0
119	**Total Gross Operating Cost and Provision &**	Line 11 (or 5.0 L123)	**1,185.0**	**1,165.1**	**(19.9)**	**1,220.0**	**1,228.7**	**8.7**	**1,221.0**	**1,257.5**	**36.5**	**1,224.3**	**1,229.3**
	Less												
120	**Deferral Account Additions**	L60 + L76	(231.3)	(233.9)	(2.6)	(212.7)	(146.1)	66.6	(197.9)	(195.9)	2.0	(157.1)	(150.9)
121	**Deferred Provisions & Other**	Line 67	(1.2)	19.5	20.7	10.0	(35.4)	(45.4)	14.0	(16.7)	(30.7)	8.1	8.1
	Add												
122	**Regulatory Account Recoveries Bf**	Line 88	207.5	202.3	(5.2)	214.9	217.9	3.0	214.9	216.3	1.4	172.5	170.9
123	**Provisions & Other Regulatory Account**	Line 96	(175.7)	(162.0)	13.7	(278.5)	(292.2)	(13.8)	(290.5)	845.8	1,136.3	50.9	47.7
124	**Total Current Operating Costs & Provisions &**	Line 98	**984.2**	**990.9**	**6.8**	**953.8**	**972.8**	**19.0**	**961.6**	**2,107.1**	**1,145.5**	**1,298.6**	**1,305.2**
125	**Current Operating Costs**	L107 + L122	**1,095.1**	**1,069.9**	**(25.2)**	**1,161.2**	**1,149.8**	**(11.4)**	**1,186.4**	**1,195.7**	**9.2**	**1,131.5**	**1,162.3**

Operating Costs - Integrated Planning
($ million)

Line		F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Reference Column	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Operating Costs by KBU											
1	Energy Planning & Analytics	6.5	5.7	(0.8)	6.2	5.9	(0.3)	6.3	6.8	0.5	7.9	8.4
2	Dam Safety	8.8	8.4	(0.4)	8.9	8.6	(0.3)	9.0	10.0	1.0	10.2	10.3
3	Stations Asset Planning	102.7	102.8	0.2	105.4	108.0	2.6	106.2	94.0	(12.2)	97.0	98.1
4	Line Asset Planning	111.3	107.0	(4.3)	112.0	114.3	2.3	111.3	121.4	10.2	127.2	128.1
5	Interconnections and Shared Assets	9.0	10.3	1.3	9.1	8.8	(0.3)	9.2	9.2	(0.1)	10.5	10.6
6	Engineering	19.9	19.2	(0.7)	20.2	20.5	0.3	20.5	21.8	1.4	24.7	25.1
7	Business Unit Support	13.1	31.3	18.2	7.6	17.6	10.0	7.6	16.0	8.4	13.2	12.5
8	**Base Operating Costs**	271.3	284.8	13.5	269.4	283.8	14.4	270.1	279.3	9.2	290.8	293.0
9	IFRS Ineligible Capitalized Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Independent Power Producer Capital Leases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Customer Crisis Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	**Total Base Operating Costs Adjustment**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	**Net Operating Costs**	271.3	284.8	13.5	269.4	283.8	14.4	270.1	279.3	9.2	290.8	293.0
	Operating Costs by Resource											
15	Labour	140.9	140.3	(0.6)	143.2	143.4	0.2	145.7	142.5	(3.2)	147.0	149.2
16	Services - ABSU	0.6	1.5	0.8	0.6	1.4	0.7	0.6	0.0	(0.6)	0.0	0.0
17	Services - Other	120.0	126.5	6.5	115.8	122.6	6.8	114.0	125.8	11.8	142.0	142.1
18	Materials	12.3	13.4	1.1	12.2	13.5	1.3	12.2	12.5	0.3	11.1	11.2
19	Buildings & Equipment	8.3	14.5	6.2	8.3	13.9	5.6	8.3	8.9	0.7	2.5	2.5
20	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	External Recoveries	(10.8)	(11.4)	(0.6)	(10.8)	(11.1)	(0.3)	(10.8)	(10.4)	0.3	(11.9)	(11.9)
22	Total	271.3	284.8	13.5	269.4	283.8	14.4	270.1	279.3	9.2	290.8	293.0

Operating Costs - Capital Infrastructure Project Delivery
($ million)

		F2017			F2018			F2019			F2020	F2021
	Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Forecast	Diff	Plan	Plan
Line	Column	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Operating Costs by KBU											
1	Project Delivery	13.4	12.7	(0.6)	14.2	13.5	(0.7)	14.3	13.9	(0.4)	14.0	14.5
2	Indigenous Relations	6.1	7.3	1.2	6.1	6.1	(0.0)	6.1	6.3	0.2	6.1	6.3
3	Environment	27.2	26.2	(0.9)	27.5	27.0	(0.6)	27.8	29.2	1.4	29.8	30.0
4	Properties	32.2	32.2	0.1	32.5	32.7	0.2	32.8	32.7	(0.1)	29.3	29.5
5	Business Unit Support	0.8	0.7	(0.1)	0.8	0.7	(0.2)	0.8	0.8	(0.0)	0.8	0.9
6	**Base Operating Costs**	79.7	79.2	(0.5)	81.1	79.9	(1.2)	81.9	82.9	1.0	80.1	81.1
7	IFRS Ineligible Capitalized Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Independent Power Producer Capital Leases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Customer Crisis Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Total Base Operating Costs Adjustment**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**Net Operating Costs**	79.7	79.2	(0.5)	81.1	79.9	(1.2)	81.9	82.9	1.0	80.1	81.1
	Operating Costs by Resource											
13	Labour	30.3	28.7	(1.6)	31.6	30.2	(1.4)	32.0	33.4	1.4	34.1	35.1
14	Services - ABSU	2.8	2.8	(0.1)	2.8	2.5	(0.3)	2.9	0.2	(2.7)	0.0	0.0
15	Services - Other	54.3	51.7	(2.6)	57.5	49.3	(8.2)	50.1	54.9	4.8	51.5	49.4
16	Materials	1.0	1.2	0.2	1.0	1.2	0.2	1.0	1.1	0.1	1.1	1.1
17	Buildings & Equipment	6.6	7.0	0.4	6.6	7.9	1.3	6.7	7.1	0.4	3.6	3.7
18	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	External Recoveries	(15.3)	(12.1)	3.3	(18.4)	(11.2)	7.2	(10.7)	(13.7)	(3.0)	(10.2)	(8.2)
20	Total	79.7	79.2	(0.5)	81.1	79.9	(1.2)	81.9	82.9	1.0	80.1	81.1

Operating Costs - Operations
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Operating Costs by KBU												
1	Program and Contract Management		13.8	11.6	(2.2)	14.1	11.9	(2.2)	14.3	12.8	(1.5)	14.0	14.2
2	Line Field Operations		67.7	69.8	2.1	68.2	71.6	3.4	68.7	68.2	(0.5)	82.3	83.1
3	Stations Field Operations		41.0	41.5	0.5	41.1	39.4	(1.7)	46.9	46.2	(0.7)	52.9	53.5
4	Distribution Design & Customer Connect		12.8	10.2	(2.6)	13.1	10.6	(2.5)	13.5	14.3	0.9	14.8	15.1
5	Construction Services		13.5	11.4	(2.1)	13.7	12.4	(1.3)	13.9	12.8	(1.0)	13.2	13.3
6	Generation System Operations		14.5	16.0	1.5	14.7	14.2	(0.5)	14.8	14.6	(0.2)	15.0	15.2
7	T&D System Operations		36.2	38.2	2.0	36.7	40.4	3.6	37.4	38.3	0.9	39.8	40.3
8	Business Unit Support		6.6	5.4	(1.1)	6.6	6.3	(0.4)	6.7	7.3	0.6	5.4	5.4
9	**Base Operating Costs**		206.1	204.2	(1.9)	208.2	206.7	(1.5)	216.2	214.5	(1.7)	237.3	240.1
10	IFRS Ineligible Capitalized Costs		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Independent Power Producer Capital Leases		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Waneta 2/3	15.0 L21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8	3.8	5.7	5.9
13	Customer Crisis Fund		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	**Total Base Operating Costs Adjustment**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8	3.8	5.7	5.9
15	**Net Operating Costs**		206.1	204.2	(1.9)	208.2	206.7	(1.5)	216.2	218.4	2.2	243.0	246.0
	Operating Costs by Resource												
16	Labour		142.2	140.4	(1.7)	144.7	142.9	(1.8)	147.4	145.9	(1.5)	158.8	161.5
17	Services - ABSU		0.7	1.8	1.1	0.7	1.3	0.7	0.7	0.0	(0.6)	0.0	0.0
18	Services - Other		48.4	46.1	(2.3)	47.9	45.4	(2.5)	53.2	57.1	3.9	67.3	67.5
19	Materials		7.5	8.9	1.4	7.5	9.5	2.0	7.5	9.3	1.8	10.1	10.1
20	Buildings & Equipment		7.4	7.0	(0.4)	7.4	7.5	0.1	7.4	6.0	(1.4)	6.8	6.8
21	Capitalized Overhead		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	External Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Total		206.1	204.2	(1.9)	208.2	206.7	(1.5)	216.2	218.4	2.2	243.0	246.0

Operating Costs - Safety
($ million)

Line		F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Operating Costs by KBU											
1	Safety System and Assurance	14.9	14.5	(0.4)	14.8	14.7	(0.1)	14.7	12.9	(1.7)	13.1	13.3
2	Learning and Development	25.0	25.7	0.7	25.0	23.2	(1.8)	25.4	25.5	0.1	25.8	26.2
3	Field Safety Services	4.9	5.7	0.8	5.0	5.7	0.7	5.1	6.2	1.1	6.6	6.7
4	Security and Emergency Management	9.3	9.4	0.2	9.3	9.2	(0.1)	9.3	9.6	0.3	10.7	10.8
5	Business Unit Support	0.5	0.6	0.1	0.5	0.6	0.1	0.5	0.6	0.1	0.6	0.6
6	**Base Operating Costs**	54.6	55.9	1.4	54.6	53.3	(1.3)	54.9	54.8	(0.2)	56.8	57.5
7	IFRS Ineligible Capitalized Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Independent Power Producer Capital Leases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Customer Crisis Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Total Base Operating Costs Adjustment**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**Net Operating Costs**	54.6	55.9	1.4	54.6	53.3	(1.3)	54.9	54.8	(0.2)	56.8	57.5
	Operating Costs by Resource											
13	Labour	35.3	35.5	0.2	35.7	35.0	(0.7)	36.1	36.0	(0.0)	37.9	38.6
14	Services - ABSU	0.2	0.4	0.2	0.2	0.4	0.2	0.2	0.0	(0.2)	0.0	0.0
15	Services - Other	18.0	17.5	(0.5)	17.8	15.9	(1.9)	17.8	17.6	(0.2)	17.8	17.8
16	Materials	0.7	1.8	1.0	0.7	1.2	0.6	0.7	0.8	0.1	0.8	0.8
17	Buildings & Equipment	0.3	0.7	0.5	0.2	0.7	0.5	0.2	0.4	0.1	0.3	0.3
18	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	External Recoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Total	54.6	55.9	1.4	54.6	53.3	(1.3)	54.9	54.8	(0.2)	56.8	57.5

Reference

Operating Costs - Finance, Technology, Supply Chain
($ million)

		F2017			F2018			F2019			F2020	F2021
	Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Forecast	Diff	Plan	Plan
Line	Column	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Operating Costs by KBU											
1	Finance	29.7	28.7	(1.0)	30.2	28.7	(1.4)	30.7	30.8	0.1	31.6	32.1
2	Technology	141.1	134.5	(6.6)	141.3	128.3	(13.0)	140.5	133.7	(6.8)	135.8	136.4
3	Supply Chain	91.8	89.9	(1.9)	92.2	89.0	(3.2)	93.0	93.3	0.2	94.5	95.5
4	Business Unit Support	0.8	0.7	(0.0)	0.8	0.7	(0.0)	0.8	0.8	(0.0)	0.8	0.8
5	**Base Operating Costs**	263.3	253.8	(9.5)	264.4	246.7	(17.7)	265.0	258.5	(6.5)	262.6	264.8
6	IFRS Ineligible Capitalized Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Independent Power Producer Capital Leases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Customer Crisis Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Total Base Operating Costs Adjustment**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Net Operating Costs**	263.3	253.8	(9.5)	264.4	246.7	(17.7)	265.0	258.5	(6.5)	262.6	264.8
	Operating Costs by Resource											
12	Labour	93.4	93.8	0.4	96.4	101.7	5.3	99.3	111.1	11.8	115.6	117.8
13	Services - ABSU	4.0	4.8	0.8	3.7	3.6	(0.2)	3.7	0.2	(3.5)	0.0	0.0
14	Services - Other	111.8	96.2	(15.5)	110.1	85.0	(25.1)	107.7	88.8	(18.9)	88.5	88.5
15	Materials	18.8	22.1	3.3	18.8	21.3	2.5	18.8	21.6	2.8	21.9	21.9
16	Buildings & Equipment	35.4	37.3	1.9	35.4	36.0	0.6	35.4	36.8	1.4	36.6	36.6
17	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	External Recoveries	0.0	(0.4)	(0.4)	0.0	(0.9)	(0.9)	0.0	0.0	0.0	0.0	0.0
19	Total	263.3	253.8	(9.5)	264.4	246.7	(17.7)	265.0	258.5	(6.5)	262.6	264.8

Operating Costs - People, Customer, Corporate Affairs
($ million)

Line	Reference / Column	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Operating Costs by KBU											
1	Human Resources	22.9	21.6	(1.3)	23.1	22.1	(1.0)	23.3	21.1	(2.2)	21.1	21.4
2	Customer Service	76.2	68.9	(7.3)	73.6	68.7	(4.9)	73.8	65.0	(8.8)	63.1	63.8
3	Conservation and Energy Management	0.6	0.6	(0.0)	0.6	0.5	(0.1)	0.6	0.6	(0.0)	0.6	0.6
4	Power Acquisitions and Contract Management	4.6	4.6	(0.1)	4.7	4.9	0.2	4.8	4.8	(0.0)	4.7	4.7
5	Communications and Community Engagement	12.8	12.4	(0.4)	12.6	13.7	1.1	12.7	13.6	0.9	12.9	13.0
6	Regulatory and Rates	6.0	5.8	(0.2)	6.1	5.4	(0.7)	6.2	6.2	0.0	6.3	6.4
7	Ethics and Merit Office	0.4	0.5	0.1	0.4	0.6	0.3	0.4	0.8	0.5	1.0	1.0
8	Business Unit Support	0.7	0.8	0.0	0.8	0.7	(0.0)	0.8	0.8	(0.0)	0.8	0.8
9	**Base Operating Costs**	124.3	115.2	(9.1)	121.8	116.8	(5.1)	122.5	112.9	(9.6)	110.6	111.9
10	IFRS Ineligible Capitalized Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Independent Power Producer Capital Leases	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Customer Crisis Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	4.0	5.3	5.3
14	**Total Base Operating Costs Adjustment**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	4.0	5.3	5.3
15	**Net Operating Costs**	124.3	115.2	(9.1)	121.8	116.8	(5.1)	122.5	116.9	(5.6)	115.9	117.2
	Operating Costs by Resource											
16	Labour	41.1	44.9	3.9	41.4	49.1	7.7	42.2	73.2	31.0	76.3	77.6
17	Services - ABSU	40.4	37.1	(3.4)	40.0	33.1	(6.8)	41.2	3.0	(38.2)	0.0	0.0
18	Services - Other	41.8	32.0	(9.8)	39.4	32.4	(7.0)	38.1	38.3	0.3	37.0	37.0
19	Materials	0.3	0.5	0.2	0.3	1.2	0.9	0.3	1.1	0.7	1.1	1.1
20	Buildings & Equipment	0.7	0.7	(0.0)	0.7	0.9	0.2	0.7	1.3	0.6	1.4	1.4
21	Capitalized Overhead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	External Recoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	Total	124.3	115.2	(9.1)	121.8	116.8	(5.1)	122.5	116.9	(5.6)	115.9	117.2

Operating Costs - Other
($ million)

Line	Reference / Column	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Operating Costs by KBU											
1	Office of the General Counsel	12.2	11.1	(1.0)	12.3	10.6	(1.7)	12.3	12.2	(0.2)	11.7	11.8
2	Office of the President and Chief Operating Officer	0.9	1.0	0.0	1.0	0.8	(0.1)	1.0	0.8	(0.1)	0.9	0.9
3	Site C Project	0.0	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0	(0.0)	0.0	0.0
4	Corporate Costs	17.2	13.1	(4.1)	18.4	28.4	10.0	19.7	38.9	19.2	13.0	13.0
5	Capitalized Costs	(283.0)	(281.8)	1.2	(283.8)	(283.9)	(0.1)	(284.6)	(285.3)	(0.7)	(285.8)	(286.2)
6	**Base Operating Costs**	(252.7)	(256.6)	(3.9)	(252.2)	(244.0)	8.2	(251.6)	(233.4)	18.1	(260.2)	(260.5)
7	IFRS Ineligible Capitalized Costs	102.9	102.9	0.0	125.3	125.3	0.0	147.7	147.7	0.0	170.1	192.5
8	Independent Power Producer Capital Leases	28.2	28.2	0.0	63.6	63.6	0.0	54.3	54.3	0.0	0.0	0.0
9	Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Customer Crisis Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Total Base Operating Costs Adjustment**	131.0	131.0	0.0	188.8	188.8	0.0	202.0	202.0	0.0	170.1	192.5
12	**Net Operating Costs**	(121.7)	(125.6)	(3.9)	(63.4)	(55.2)	8.2	(49.6)	(31.4)	18.1	(90.2)	(68.1)
	Operating Costs by Resource											
13	Labour	6.2	4.1	(2.1)	6.3	19.9	13.6	6.4	15.4	8.9	6.2	6.3
14	Services - ABSU	0.0	(0.3)	(0.3)	0.0	(0.4)	(0.4)	0.0	0.0	(0.0)	0.0	0.0
15	Services - Other	52.1	49.2	(2.8)	88.6	83.6	(5.1)	80.7	90.6	9.9	19.1	19.1
16	Materials	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1
17	Buildings & Equipment	0.2	0.2	0.0	0.2	0.2	0.0	0.2	0.2	0.0	0.2	0.2
18	Capitalized Overhead	(180.2)	(179.0)	1.2	(158.6)	(158.6)	(0.1)	(136.9)	(137.6)	(0.7)	(115.8)	(93.8)
19	External Recoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	Total	(121.7)	(125.6)	(3.9)	(63.4)	(55.2)	8.2	(49.6)	(31.4)	18.1	(90.2)	(68.1)

Taxes
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Generation												
1	Grants in Lieu		23.8	24.0	0.1	24.4	24.4	(0.0)	25.4	25.6	0.2	26.9	27.9
2	School Taxes		16.7	16.5	(0.2)	17.3	16.5	(0.7)	17.8	16.5	(1.2)	17.4	18.3
3	Total		40.5	40.5	(0.0)	41.6	40.9	(0.7)	43.2	42.2	(1.0)	44.3	46.3
	Transmission												
4	Grants in Lieu		51.9	52.1	0.3	54.0	55.0	1.0	57.2	60.4	3.3	63.6	65.7
5	School Taxes		85.7	85.8	0.0	87.7	88.8	1.1	90.0	91.6	1.5	94.0	98.0
6	Total		137.6	137.9	0.3	141.7	143.8	2.1	147.2	152.0	4.8	157.6	163.7
	Distribution												
7	Grants in Lieu		7.4	7.5	0.1	7.8	7.8	0.1	8.4	8.2	(0.1)	8.5	8.9
8	School Taxes		19.4	19.3	(0.1)	19.8	19.7	(0.1)	20.3	20.1	(0.1)	20.6	24.0
9	Total		26.8	26.8	0.0	27.5	27.5	(0.0)	28.6	28.4	(0.3)	29.1	32.9
	Customer Care												
10	IPP Capital Leases		2.6	2.6	0.0	4.2	4.2	0.0	2.5	2.5	0.0	0.0	0.0
	Waneta 2/3												
11	Teck portion of property taxes	15.0 L23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.6	0.6
12	Total		2.6	2.6	0.0	4.2	4.2	0.0	2.5	2.6	0.1	0.6	0.6
	Business Support												
13	Grants in Lieu		10.5	10.0	(0.5)	11.3	10.5	(0.8)	11.7	11.0	(0.7)	11.8	12.2
14	School Taxes		5.3	5.7	0.4	5.4	6.1	0.6	5.6	6.1	0.5	6.3	6.5
15	Total		15.8	15.7	(0.1)	16.7	16.5	(0.2)	17.2	17.1	(0.1)	18.2	18.7
	Total Before Regulatory Accounts												
16	Grants in Lieu	L1+L4+L7+L13	93.6	93.6	(0.1)	97.5	97.7	0.2	102.6	105.3	2.7	110.8	114.8
17	School Taxes	L2+L5+L8+L14	127.1	127.3	0.2	130.2	131.1	0.9	133.6	134.3	0.7	138.3	146.8
18	IPP Capital Leases	L10	2.6	2.6	0.0	4.2	4.2	0.0	2.5	2.5	0.0	0.0	0.0
19	Waneta 2/3 Property Taxes	L11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.6	0.6
20	Total		223.3	223.5	0.2	231.8	232.9	1.1	238.7	242.2	3.5	249.8	262.2
	Deferral Account Additions												
21	Transfers to NHDA		0.0	(0.4)	(0.4)	0.0	(1.9)	(1.9)	0.0	0.0	0.0	0.0	0.0
22	**Total Gross Taxes**	L20 + L21	223.3	223.1	(0.2)	231.8	231.1	(0.8)	238.7	242.2	3.5	249.8	262.2
	Deferral Account Additions												
23	Transfers to NHDA		0.0	0.4	0.4	0.0	1.9	1.9	0.0	0.0	0.0	0.0	0.0
24	**Total Current Taxes**	L22 + L23	223.3	223.5	0.2	231.8	232.9	1.1	238.7	242.2	3.5	249.8	262.2
	Allocation of Current Taxes												
25	Generation	Line 3	40.5	40.5	(0.0)	41.6	40.9	(0.7)	43.2	42.2	(1.0)	44.3	46.3
26	Transmission	Line 6	137.6	137.9	0.3	141.7	143.8	2.1	147.2	152.0	4.8	157.6	163.7
27	Distribution	Line 9	26.8	26.8	0.0	27.5	27.5	(0.0)	28.6	28.4	(0.3)	29.1	32.9
28	Customer Care	Line 12	2.6	2.6	0.0	4.2	4.2	0.0	2.5	2.6	0.1	0.6	0.6
29	Business Support	Line 15	15.8	15.7	(0.1)	16.7	16.5	(0.2)	17.2	17.1	(0.1)	18.2	18.7
30	Total		223.3	223.5	0.2	231.8	232.9	1.1	238.7	242.2	3.5	249.8	262.2

Depreciation and Amortization
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Amortization of Capital Assets												
1	Generation	12.2 L8:L9	198.0	195.9	(2.2)	208.3	198.8	(9.5)	226.7	234.9	8.2	257.0	262.8
2	Transmission	12.3 L8:L9	205.8	206.8	1.1	216.0	216.3	0.3	225.6	223.7	(1.9)	229.8	231.9
3	Distribution	12.4 L8:L9	185.3	184.3	(1.1)	191.2	191.4	0.3	197.8	202.3	4.5	209.6	219.8
4	Business Support	12.1 L8:L9	168.4	168.6	0.1	176.3	185.8	9.5	178.0	187.7	9.8	185.7	188.4
5	Total		757.5	755.5	(2.0)	791.7	792.2	0.5	828.0	848.6	20.6	882.1	902.8
	Dismantling Costs												
6	Generation		0.9	0.6	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Transmission		3.4	2.4	(1.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Distribution		3.8	5.6	1.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Business Support		0.5	0.1	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Total		8.6	8.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	IPP Capital Leases												
11	IPP Capital Leases		17.0	17.0	0.0	29.4	29.4	0.0	22.8	22.8	(0.0)	30.2	30.2
12	Total		17.0	17.0	0.0	29.4	29.4	0.0	22.8	22.8	(0.0)	30.2	30.2
	Other Leases												
13	Amortization		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.4	3.4
	Deferral Account Additions												
14	Transfers to NHDA		0.0	(3.3)	(3.3)	0.0	(14.0)	(14.0)	0.0	0.0	0.0	0.0	0.0
15	Total		0.0	(3.3)	(3.3)	0.0	(14.0)	(14.0)	0.0	0.0	0.0	0.0	0.0
16	**Total Gross Amortization**		783.2	777.9	(5.3)	821.1	807.6	(13.4)	850.9	871.5	20.6	915.7	936.5
	Deferral Account Additions												
17	Transfers to NHDA		0.0	3.3	3.3	0.0	14.0	14.0	0.0	0.0	0.0	0.0	0.0
	Transfer to Regulatory Account												
18	Amortization on Additions Varian	13.0 L35	0.0	2.0	2.0	0.0	(0.7)	(0.7)	0.0	(21.8)	(21.8)	0.0	0.0

Depreciation and Amortization
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Regulatory Account Recoveries												
	DSM Amortization												
19	Generation - 90%	(2.2 L4:L5) * 90%	80.2	80.2	0.0	87.0	86.0	(1.0)	92.5	89.6	(2.9)	93.8	97.4
20	Transmission - 5%	(2.2 L4:L5) * 5%	4.5	8.9	4.5	4.8	9.6	4.7	5.1	5.0	(0.2)	5.2	5.4
21	Distribution - 5%	(2.2 L4:L5) * 5%	4.5	0.0	(4.5)	4.8	0.0	(4.8)	5.1	5.0	(0.2)	5.2	5.4
22	Total		89.1	89.1	0.0	96.7	95.6	(1.1)	102.8	99.6	(3.2)	104.2	108.3
	FRSR Amortization												
23	Generation	Line 6	(0.9)	(0.6)	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	Transmission	Line 7	(3.4)	(2.4)	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	Distribution	Line 8	(3.8)	(5.6)	(1.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Business Support	Line 9	(0.5)	(0.1)	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	Total		(8.6)	(8.7)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	**Pre-1996 CIAC Amortization**		**0.7**	**0.7**	(0.0)	**3.2**	**3.2**	0.0	**4.9**	**4.9**	0.0	**5.1**	**5.1**
	Capital Additions Regulatory Account												
29	Business Support		**(3.6)**	(3.6)	0.0	**(3.4)**	(3.4)	0.0	**(3.3)**	(3.3)	0.0	**10.7**	**10.3**
30	Total		(3.6)	(3.6)	0.0	(3.4)	(3.4)	0.0	(3.3)	(3.3)	0.0	10.7	10.3
31	**Total Recoveries**		77.6	77.5	(0.0)	96.5	95.4	(1.1)	104.4	101.2	(3.2)	119.9	123.7
32	**Total Current Amortization**		860.7	860.7	0.0	917.5	916.3	(1.2)	955.3	950.8	(4.5)	1,035.6	1,060.2
	Allocation of Current Amortization												
33	Generation	L1+L19	278.2	276.0	(2.2)	295.3	284.8	(10.5)	319.2	324.5	5.3	350.8	360.3
34	Transmission	L2+L20	210.2	215.7	5.5	220.8	225.8	5.0	230.7	228.7	(2.0)	235.0	237.3
35	Distribution	L3+L21+L28	190.5	184.9	(5.5)	199.2	194.7	(4.6)	207.8	212.2	4.3	219.9	230.3
36	Customer Care	L12	17.0	17.0	0.0	29.4	29.4	0.0	22.8	22.8	(0.0)	30.2	30.2
37	Business Support	L4+L13+L18+L29	164.9	167.0	2.2	172.8	181.7	8.8	174.7	162.6	(12.1)	199.8	202.1
38	Total		860.7	860.7	0.0	917.5	916.3	(1.2)	955.3	950.8	(4.5)	1,035.6	1,060.2

Finance Charges
($ million)

			F2017			F2018			F2019			F2020	F2021
		Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Forecast	Diff	Plan	Plan
Line		Column	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
1	**Total Gross Finance Charges**	L8 + L20	708.8	579.2	(129.6)	735.0	805.9	71.0	773.8	684.6	(89.2)	757.5	726.9
	Regulatory Account Additions												
2	FX Gains/Losses		5.8	3.4	(2.4)	(6.8)	(4.2)	2.6	(3.5)	(0.0)	3.5	(2.1)	(0.8)
3	Deferred IPP Capital Leases (Total Finance Charge Reg. Account Additions)		0.0	(5.6)	(5.6)	0.0	(26.5)	(26.5)	0.0	0.1	0.1	0.0	0.0
4	Accretion - First Nations		17.2	17.2	0.0	17.2	17.2	(0.0)	17.4	17.5	0.0	17.6	18.0
5	Accretion - Environmental		3.9	3.9	0.0	3.8	4.4	0.6	3.7	6.0	2.3	5.5	4.8
6	Accretion - Arrow Water		0.2	0.2	0.0	0.2	0.2	0.0	0.2	0.2	0.0	0.2	0.1
7	Debt Management		0.0	(187.1)	(187.1)	0.0	29.3	29.3	0.0	(102.4)	(102.4)	0.0	0.0
8	Total		27.1	(168.0)	(195.1)	14.4	20.4	6.1	17.7	(78.8)	(96.5)	21.2	22.2
9	**Adj. for Regulatory Account Additions**		681.7	747.2	65.5	720.6	785.5	64.9	756.1	763.3	7.2	736.3	704.8
	Total Before Regulatory Accounts												
10	Sinking Fund Income	Line 70	(5.5)	(8.2)	(2.7)	(5.6)	(8.3)	(2.7)	(5.6)	(7.5)	(1.9)	(6.7)	(6.9)
11	Long-Term Debt Costs	Line 86	746.9	741.3	(5.6)	793.8	774.5	(19.3)	825.8	813.7	(12.1)	833.7	870.3
12	Short-Term Debt Costs	Line 95	19.2	15.8	(3.4)	36.2	20.9	(15.3)	52.0	37.2	(14.8)	70.1	66.5
13	Interest Capitalized	Line 105	(92.9)	(81.2)	11.7	(128.7)	(108.9)	19.8	(152.1)	(146.3)	5.8	(178.8)	(239.8)
14	Other (Income) / Loss		(3.0)	(12.7)	(9.7)	(10.6)	1.5	12.1	4.6	34.1	29.5	44.8	46.3
15	IPP Capital Leases		25.1	25.1	0.0	44.7	44.7	0.0	42.4	42.4	0.0	4.2	2.8
16	Accretion - Non-Deferrable		1.0	1.2	0.2	1.1	1.1	(0.0)	1.1	1.2	0.0	1.2	1.2
17	Non-Current PEB		(6.1)	66.0	72.1	(8.5)	62.0	70.5	(10.9)	(10.9)	(0.0)	(33.2)	(36.7)
18	NTL Supplemental Interest Income		(3.0)	0.0	3.0	(1.8)	(2.0)	(0.2)	(1.2)	(0.5)	0.7	0.0	0.0
19	Other Leases		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0
20	Total		681.7	747.2	65.5	720.6	785.5	64.9	756.1	763.3	7.2	736.3	704.8
21	Total Finance Charge Regulatory Acct. A	L16-L3-L20-L25-L26-L27	0.0	12.6	12.6	0.0	25.1	25.1	0.0	(28.8)	(28.8)	0.0	0.0
22	Site C Project (IFRS 14 IDC impact)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.7
	Interest on Regulatory Accounts												
23	Interest on Deferral Accounts	2.1 L25	(41.5)	(41.1)	0.4	(34.3)	(26.5)	7.8	(26.6)	(3.8)	22.8	8.9	3.0
24	Interest on Other Reg Accounts	2.2 L205	(34.3)	(34.2)	0.0	(34.1)	(35.2)	(1.1)	(33.5)	(34.8)	(1.3)	(33.2)	(30.5)
25	Total		(75.8)	(75.3)	0.4	(68.3)	(61.6)	6.7	(60.1)	(38.6)	21.5	(24.3)	(27.6)
	Regulatory Account Recoveries												
26	Amort. of FX Gains/Losses		0.6	0.4	(0.2)	(38.1)	(38.3)	(0.2)	(38.6)	(38.6)	0.0	0.2	(0.8)
27	Non-Current Pension		0.0	(72.6)	(72.6)	0.0	(70.0)	(70.0)	0.0	0.0	0.0	0.0	0.0
28	Total Finance Charges		(101.8)	(101.8)	0.0	(101.8)	(101.8)	0.0	(101.8)	(101.8)	0.0	(4.4)	(4.4)
29	Debt Management		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(12.4)	(12.4)
30	F2017 Correction (RRA Adjustment)		0.0	(0.8)	(0.8)	0.0	0.8	0.8	0.0	0.0	0.0	0.0	0.0
31	Total		(101.3)	(174.9)	(73.6)	(139.9)	(209.4)	(69.5)	(140.5)	(140.4)	0.0	(16.6)	(17.6)
32	**Total Current Finance Chrgs**	L3+L20+L21+L22+L25+L31	504.6	504.0	(0.7)	512.4	513.1	0.7	555.5	555.6	0.0	697.5	662.3

Finance Charges
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Portion of Rate Base												
33	Generation	10.0 L25	41.9%	41.6%	(0.3%)	41.9%	41.3%	(0.6%)	43.1%	44.2%	1.1%	46.6%	46.5%
34	Transmission	10.0 L26	35.2%	35.5%	0.3%	35.1%	35.6%	0.4%	34.4%	33.7%	(0.7%)	32.0%	31.6%
35	Distribution	10.0 L27	23.0%	23.0%	0.0%	23.0%	23.1%	0.1%	22.5%	22.1%	(0.4%)	21.4%	21.9%
36	Total		100.0%	100.0%	-	100.0%	100.0%	-	100.0%	100.0%	-	100.0%	100.0%
	Allocation of Current Finance Charges												
37	Generation		211.3	209.5	(1.8)	214.5	212.0	(2.5)	239.3	245.5	6.2	324.9	308.2
38	Transmission		177.4	178.7	1.3	180.0	182.5	2.4	191.0	187.0	(3.9)	223.3	209.0
39	Distribution		115.8	115.7	(0.1)	117.9	118.7	0.8	125.2	123.0	(2.2)	149.3	145.1
40	Total		504.6	504.0	(0.7)	512.4	513.1	0.7	555.5	555.6	0.0	697.5	662.3
	Net Debt												
41	Sinking Funds	Line 71	(179.5)	(179.4)	0.1	(175.8)	(181.8)	(6.0)	(176.2)	(189.4)	(13.3)	(192.3)	(197.6)
42	Temporary Investments		**(10.0)**	**(48.9)**	(38.9)	**(10.0)**	**(41.9)**	(31.9)	**(10.0)**	**(10.0)**	0.0	**(10.0)**	**(10.0)**
43	Long-Term Debt	Line 81	16,885.1	17,185.3	300.2	18,788.3	18,311.1	(477.2)	19,060.2	19,400.5	340.3	20,701.4	21,891.2
44	Short-Term Debt	Line 90	2,953.9	2,838.5	(115.3)	2,211.7	2,053.0	(158.7)	2,902.4	3,031.7	129.3	2,919.6	2,970.1
45	Subtotal		19,649.5	19,795.5	146.1	20,814.3	20,140.4	(673.9)	21,776.5	22,232.8	456.3	23,418.7	24,653.7
46	WACD Adjustment		**144.5**	**180.1**	35.6	**146.3**	**178.8**	32.5	**151.8**	**164.6**	12.8	**172.0**	**180.1**
47	End of Year		19,794.0	19,975.6	181.7	20,960.6	20,319.2	(641.4)	21,928.3	22,397.4	469.1	23,590.7	24,833.8
48	Mid-Year Balance		18,977.4	19,068.2	90.8	20,377.3	20,147.4	(229.9)	21,444.4	21,358.3	(86.1)	22,994.0	24,212.3
	Weighted Average Cost of Debt (WACD) Rate												
49	Total Gross Finance Charges	Line 1	708.8	579.2	(129.6)	735.0	805.9	71.0	773.8	684.6	(89.2)	757.5	726.9
50	WACD Adjustment		**55.4**	**177.6**	122.2	**90.9**	**(8.5)**	(99.4)	**112.0**	**166.2**	54.2	**133.9**	**197.5**
51	Finance Charges for WACD		764.2	756.8	(7.4)	825.9	797.5	(28.4)	885.8	850.7	(35.1)	891.4	924.4
52	Weighted Average Cost of Debt (WACD) Rate		4.03%	3.97%	(0.06%)	4.05%	3.96%	(0.09%)	4.13%	3.98%	(0.15%)	3.88%	3.82%
	Increase in Cash												
53	Net Income	9.0 L32	684.0	683.5	(0.5)	698.0	684.0	(14.0)	712.0	(424.3)	(1,136.3)	712.0	712.0
54	Dividend (One Year Lag)	9.0 L3	(325.6)	(584.6)	(259.0)	(272.0)	(159.0)	113.0	(172.0)	(59.0)	113.0	0.0	0.0
55	Amortization	7.0 L16	783.2	777.9	(5.3)	821.1	807.6	(13.4)	850.9	871.5	20.6	915.7	936.5
56	Deferral Account Additions	2.1 L24	0.0	63.3	63.3	0.0	203.7	203.7	0.0	222.8	222.8	3.1	3.5
57	Deferral Account Recoveries	2.1 L26	223.5	223.7	0.2	231.3	233.2	1.9	241.8	241.2	(0.7)	(164.5)	(164.5)
58	Regulatory Account Additions	2.2 L204	(259.7)	(46.8)	212.9	(217.1)	(237.7)	(20.6)	(201.6)	(184.0)	17.6	(168.2)	(162.3)
59	Regulatory Account Recoveries	2.2 L206	8.0	(57.0)	(65.1)	(107.0)	(188.4)	(81.3)	(111.6)	1,023.0	1,134.6	326.7	324.7
60	First Nations Provisions	2.2 L16	(5.3)	(3.3)	2.0	0.0	0.9	0.9	0.0	2.4	2.4	0.0	0.0
61	Environmental Provisions	2.2 L91	0.0	(28.0)	(28.0)	0.0	(4.0)	(4.0)	0.0	(4.3)	(4.3)	0.0	0.0
62	Capital Expenditures	13.0 L12	(2,603.9)	(2,435.5)	168.4	(2,411.9)	(2,464.9)	(53.0)	(2,424.6)	(3,912.1)	(1,487.5)	(2,988.3)	(3,104.2)
63	Contributions in Aid	11.0 L30	86.4	138.4	52.0	100.2	156.2	56.1	106.4	146.9	40.4	157.8	148.5
64	Change in Sinking Funds	Line 69	(7.4)	(4.6)	2.8	9.3	5.9	(3.4)	5.2	(0.1)	(5.3)	3.8	1.6
65	Change in Working Cap & Other		**(212.3)**	**(538.2)**	(325.9)	**(19.1)**	**622.1**	641.2	**24.9**	**8.1**	(16.8)	**13.2**	**63.9**
66	F17-F19 RRA Compliance Filing Adjustment		**2.7**	**0.0**	(2.7)	**6.1**	**0.0**	(6.1)	**6.0**	**0.0**	(6.0)	**0.0**	**0.0**
67	Total		(1,626.4)	(1,811.2)	(184.9)	(1,161.1)	(340.2)	820.8	(962.6)	(2,068.1)	(1,105.5)	(1,188.8)	(1,240.3)

Finance Charges
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Sinking Funds												
68	Beginning of Year		166.6	166.6	0.0	179.5	179.4	(0.1)	175.8	181.8	6.0	189.4	192.3
69	Change in Sinking Funds		7.4	4.6	(2.8)	(9.3)	(5.9)	3.4	(5.2)	0.1	5.3	(3.8)	(1.6)
70	Sinking Fund Income		5.5	8.2	2.7	5.6	8.3	2.7	5.6	7.5	1.9	6.7	6.9
71	End of Year		179.5	179.4	(0.1)	175.8	181.8	6.0	176.2	189.4	13.3	192.3	197.6
72	Mid-Year Balance		173.0	173.0	(0.0)	177.6	180.6	3.0	176.0	185.6	9.7	190.9	194.9
	Long-Term Debt												
73	Beginning of Year		15,836.6	15,836.6	0.0	16,885.1	17,185.3	300.2	18,788.3	18,311.1	(477.2)	19,400.5	20,701.4
74	Bonds Retired		0.0	0.0	0.0	(40.0)	(40.0)	0.0	(1,279.4)	(1,286.7)	(7.3)	(175.0)	(1,099.8)
75	Bonds Issued		200.0	1,350.0	1,150.0	0.0	1,200.0	1,200.0	0.0	2,450.0	2,450.0	0.0	0.0
76	Bonds Planned Issues		800.0	0.0	(800.0)	2,025.0	0.0	(2,025.0)	1,600.0	0.0	(1,600.0)	1,500.0	2,300.0
77	Revaluation of Foreign $ Debt		58.2	19.1	(39.1)	(70.5)	19.7	90.2	(38.2)	(34.9)	3.3	(20.5)	(8.0)
78	Revaluation to Fair Value		0.0	(1.5)	(1.5)	0.0	(1.7)	(1.7)	0.0	0.0	0.0	0.0	0.0
79	Premiums/(Discounts) on Issues		1.4	(9.7)	(11.1)	0.0	(44.0)	(44.0)	0.0	(31.8)	(31.8)	0.0	0.0
80	Amortization of Issue Costs		(11.1)	(9.2)	1.9	(11.3)	(8.2)	3.1	(10.5)	(7.2)	3.3	(3.6)	(2.4)
81	End of Year		16,885.1	17,185.3	300.2	18,788.3	18,311.1	(477.2)	19,060.2	19,400.5	340.3	20,701.4	21,891.2
82	Mid-Year Balance		16,360.9	16,511.0	150.1	17,836.7	17,748.2	(88.5)	18,924.3	18,855.8	(68.5)	20,051.0	21,296.3
83	Interest Rate - Planned Issues		2.96%			3.67%			4.60%			3.50%	3.86%
84	Debt Costs - Excluding Planned		735.1	741.3	6.2	733.0	774.5	41.5	691.0	813.7	122.7	807.4	773.4
85	Debt Costs - Planned Issues		11.8	0.0	(11.8)	60.8	0.0	(60.8)	134.8	0.0	(134.8)	26.3	96.9
86	Total Long-Term Debt Costs		746.9	741.3	(5.6)	793.8	774.5	(19.3)	825.8	813.7	(12.1)	833.7	870.3
	Short-Term Debt												
87	Beginning of Year		2,376.0	2,376.0	0.0	2,953.9	2,838.5	(115.3)	2,211.7	2,053.0	(158.7)	3,031.7	2,919.6
88	Increase in Cash Requirement	Line 67	1,626.4	1,811.2	184.9	1,161.1	340.2	(820.8)	962.6	2,068.1	1,105.5	1,188.8	1,240.3
89	Change in Long-Term Debt	L73 - L81	(1,048.5)	(1,348.7)	(300.2)	(1,903.2)	(1,125.8)	777.4	(271.9)	(1,089.4)	(817.5)	(1,300.9)	(1,189.8)
90	End of Year		2,953.9	2,838.5	(115.3)	2,211.7	2,053.0	(158.7)	2,902.4	3,031.7	129.3	2,919.6	2,970.1
91	Mid-Year Balance		2,664.9	2,607.3	(57.7)	2,582.8	2,445.8	(137.0)	2,557.1	2,542.3	(14.7)	2,975.6	2,944.8
92	Interest Rate		0.72%			1.40%			2.03%			2.37%	2.59%
93	Debt Costs - Interest		19.2	15.8	(3.4)	36.2	20.9	(15.3)	52.0	37.2	(14.8)	70.4	76.2
94	Debt Costs - Other		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.3)	(9.7)
95	Total Short-Term Debt Costs		19.2	15.8	(3.4)	36.2	20.9	(15.3)	52.0	37.2	(14.8)	70.1	66.5
	Interest During Construction (IDC) Rate												
96	Finance Charges for WACD	Line 51	764.2	756.8	(7.4)	825.9	797.5	(28.4)	885.8	850.7	(35.1)	891.4	924.4
97	Amortization of Debt Management Reg.	Line 29	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.4	12.4
98	Finance Charges for IDC		764.2	756.8	(7.4)	825.9	797.5	(28.4)	885.8	850.7	(35.1)	903.8	936.8
99	Net Debt Mid-Year Balance	Line 48	18,977.4	19,068.2	90.8	20,377.3	20,147.4	(229.9)	21,444.4	21,358.3	(86.1)	22,994.0	24,212.3
100	Interest During Construction (IDC) Rate		4.03%	3.97%	(0.06%)	4.05%	3.96%	(0.09%)	4.13%	3.98%	(0.15%)	3.93%	3.87%
	Interest Capitalized												
101	Unfinished Construction	13.0 L26	2,894.0	2,936.9	42.9	3,788.1	3,859.9	71.8	4,267.5	4,382.4	114.9	5,251.6	6,863.1
102	Less Not Subject to IDC		(587.2)	(891.0)	(303.8)	(613.1)	(1,108.8)	(495.7)	(584.6)	(708.7)	(124.1)	(703.7)	(665.3)
103	Unfinished Subject to IDC		2,306.8	2,045.9	(261.0)	3,175.0	2,751.1	(423.9)	3,682.9	3,673.7	(9.2)	4,547.9	6,197.8
104	Interest During Construction (IDC) Rate	Line 100	4.03%	3.97%	(0.06%)	4.05%	3.96%	(0.09%)	4.13%	3.98%	(0.15%)	3.93%	3.87%
105	Interest Capitalized		92.9	81.2	(11.7)	128.7	108.9	(19.8)	152.1	146.3	(5.8)	178.8	239.8

Return on Equity
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Shareholder's Equity												
1	Retained Earnings - Beginning of Year		4,458.0	4,458.0	0.0	4,870.0	4,882.5	12.5	5,396.0	5,407.5	11.5	4,924.3	5,635.4
2	Gross Return on Equity	Line 32	684.0	683.5	(0.5)	698.0	684.0	(14.0)	712.0	(424.3)	(1,136.3)	712.0	712.0
3	Dividend to Province	Line 14	(272.0)	(259.0)	13.0	(172.0)	(159.0)	13.0	(72.0)	(59.0)	13.0	0.0	0.0
4	Other Leases		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.8)	0.0
5	Retained Earnings - End of Year		4,870.0	4,882.5	12.5	5,396.0	5,407.5	11.5	6,036.0	4,924.3	(1,111.7)	5,635.4	6,347.4
6	Accum Other Comp Income		42.4	230.0	187.6	42.4	242.7	200.3	42.4	297.5	255.1	49.0	49.0
7	OCI Deferred (Pension)		0.0	(203.2)	(203.2)	0.0	(193.6)	(193.6)	0.0	(248.5)	(248.5)	0.0	0.0
8	Total Shareholder's Equity		4,912.4	4,909.3	(3.1)	5,438.4	5,456.6	18.2	6,078.4	4,973.3	(1,105.1)	5,684.4	6,396.4
	Dividend to Province												
9	Net Income	Line 2	684.0			698.0			712.0			712.0	712.0
10	Distributable Surplus		684.0			698.0			712.0			712.0	712.0
11	Maximum Dividend Percentage		85.0%										
12	Maximum Dividend Amount		581.4										
13	Minimum Equity Percentage		20.0%										
14	Dividend to Province		272.0			172.0			72.0			0.0	0.0
	Capitalization												
15	Net Debt	8.0 L45	19,649.5	19,795.5	146.1	20,814.3	20,140.4	(673.9)	21,776.5	22,232.8	456.3	23,418.7	24,653.7
16	Shareholder's Equity	Line 8	4,912.4	4,909.3	(3.1)	5,438.4	5,456.6	18.2	6,078.4	4,973.3	(1,105.1)	5,684.4	6,396.4
17	Total		24,561.9	24,704.8	143.0	26,252.7	25,597.0	(655.7)	27,854.9	27,206.1	(648.9)	29,103.1	31,050.2
	Capital Structure												
18	Net Debt		80.0%	80.1%	0.1%	79.3%	78.7%	(0.6%)	78.2%	81.7%	3.5%	80.5%	79.4%
19	Equity		20.0%	19.9%	(0.1%)	20.7%	21.3%	0.6%	21.8%	18.3%	(3.5%)	19.5%	20.6%
20	Total		100.0%	100.0%	-	100.0%	100.0%	-	100.0%	100.0%	-	100.0%	100.0%
	Deemed Equity												
21	Rate Base	10.0 L23	19,542.5	19,195.4	(347.1)	20,174.7	19,787.8	(386.9)	21,665.7	22,575.7	910.0	22,943.0	23,380.3
22	Pre-1996 Customer Contns	2.2 L39	(91.4)	(91.4)	0.0	(88.2)	(88.2)	0.0	(83.3)	(83.3)	0.0	(78.2)	(73.1)
23	Powerex & Powertech Assets		42.4	51.6	9.2	43.2	69.2	26.0	43.6	70.3	26.7	71.9	73.7
24	Allowance for Working Capital		250.0	250.0	0.0	250.0	250.0	0.0	250.0	250.0	0.0	250.0	250.0
25	Total		19,743.5	19,405.5	(337.9)	20,379.7	20,018.7	(360.9)	21,876.0	22,812.7	936.7	23,186.8	23,631.0
26	Deemed Equity Percentage		30.0%	30.0%	0.0%	30.0%	30.0%	0.0%	30.0%	30.0%	0.0%	30.0%	30.0%
27	Year-End Deemed Equity		5,923.0	5,821.7	(101.4)	6,113.9	6,005.6	(108.3)	6,562.8	6,843.8	281.0	6,956.0	7,089.3
28	Mid-Year Deemed Equity		5,783.3	5,732.7	(50.7)	6,018.5	5,913.6	(104.8)	6,338.4	6,424.7	86.4	6,899.9	7,022.7
29	Achieved ROE			11.92%			11.57%			(6.60%)			
30	Allowed ROE / Derived ROE (F18-F21)		11.83%			11.60%			11.23%			10.32%	10.14%
31	Return on Equity		684.0	683.5	(0.5)	698.0	684.0	(14.0)	712.0	(424.3)	(1,136.3)	712.0	712.0
32	Gross Return on Equity		684.0	683.5	(0.5)	698.0	684.0	(14.0)	712.0	(424.3)	(1,136.3)	712.0	712.0

Return on Equity
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	F2010 ROE Regulatory Account Transfers												
33	Recoveries		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	**Current Return on Equity**		684.0	683.5	(0.5)	698.0	684.0	(14.0)	712.0	(424.3)	(1,136.3)	712.0	712.0
	Portion of Rate Base												
36	Generation	10.0 L25	41.9%	41.6%	(0.3%)	41.9%	41.3%	(0.6%)	43.1%	44.2%	1.1%	46.6%	46.5%
37	Transmission	10.0 L26	35.2%	35.5%	0.3%	35.1%	35.6%	0.4%	34.4%	33.7%	(0.7%)	32.0%	31.6%
38	Distribution	10.0 L27	23.0%	23.0%	0.0%	23.0%	23.1%	0.1%	22.5%	22.1%	(0.4%)	21.4%	21.9%
39	Total		100.0%	100.0%	-	100.0%	100.0%	-	100.0%	100.0%	-	100.0%	100.0%
	Allocation of ROE												
40	Generation	L35 x L36	286.5	284.2	(2.3)	292.2	282.6	(9.6)	306.8	(187.5)	(494.2)	331.7	331.3
41	Transmission	L35 x L37	240.5	242.4	1.9	245.3	243.2	(2.0)	244.8	(142.8)	(387.6)	227.9	224.7
42	Distribution	L35 x L38	157.0	157.0	(0.0)	160.6	158.2	(2.3)	160.5	(93.9)	(254.4)	152.4	156.0
43	Total		684.0	683.5	(0.5)	698.0	684.0	(14.0)	712.0	(424.3)	(1,136.3)	712.0	712.0
	RSRA Write-off												
44	Generation	L31 x L36			0.0			0.0		(502.1)	(502.1)		
45	Transmission	L31 x L37			0.0			0.0		(382.5)	(382.5)		
46	Distribution	L31 x L38			0.0			0.0		(251.6)	(251.6)		
47	Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1,136.3)	(1,136.3)	0.0	0.0

Rate Base
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
		Column	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Generation												
1	Net Assets in Service	12.2 L13	6,680.0	6,501.3	(178.7)	6,855.1	6,706.0	(149.1)	7,957.1	8,991.0	1,034.0	9,072.4	9,291.5
2	Net Contributions	11.0 L9	(3.1)	(2.8)	0.3	(2.8)	(2.5)	0.3	(2.4)	(2.2)	0.2	(1.9)	(1.7)
3	90% of Net DSM	2.2 L6 x 90%	838.6	824.0	(14.6)	859.2	812.2	(46.9)	881.7	834.4	(47.4)	838.8	854.7
4	Total		7,515.5	7,322.5	(193.0)	7,711.4	7,515.7	(195.7)	8,836.4	9,823.2	986.8	9,909.3	10,144.6
5	Mid-Year		7,348.6	7,252.1	(96.5)	7,613.5	7,419.1	(194.4)	8,273.9	8,669.5	395.6	9,866.3	10,027.0
	Transmission												
6	Net Assets in Service	12.3 L12	6,771.5	6,764.0	(7.4)	6,984.7	6,946.3	(38.4)	7,209.1	7,250.2	41.0	7,307.2	7,297.6
7	Net Contributions	11.0 L18	(530.3)	(536.3)	(6.1)	(537.8)	(537.5)	0.3	(549.6)	(540.1)	9.6	(549.0)	(548.5)
8	5% of Net DSM	2.2 L6 x 5%	46.6	91.6	45.0	47.7	45.1	(2.6)	49.0	46.4	(2.6)	46.6	47.5
9	Total		6,287.8	6,319.3	31.5	6,494.6	6,453.9	(40.8)	6,708.5	6,756.5	48.0	6,804.8	6,796.6
10	Mid-Year		6,170.0	6,185.8	15.7	6,391.2	6,386.6	(4.6)	6,601.6	6,605.2	3.6	6,780.6	6,800.7
	Distribution												
11	Net Assets in Service	12.4 L12	5,145.8	5,194.3	48.5	5,328.4	5,425.2	96.8	5,516.9	5,723.6	206.7	5,988.9	6,280.4
12	Net Contributions	11.0 L28	(1,079.8)	(1,125.4)	(45.6)	(1,121.3)	(1,229.4)	(108.2)	(1,164.1)	(1,322.0)	(157.9)	(1,416.0)	(1,506.6)
13	5% of Net DSM	2.2 L6 x 5%	46.6	0.0	(46.6)	47.7	45.1	(2.6)	49.0	46.4	(2.6)	46.6	47.5
14	Total		4,112.6	4,068.9	(43.7)	4,254.9	4,240.9	(14.0)	4,401.9	4,448.0	46.1	4,619.5	4,821.3
15	Mid-Year		4,028.3	4,006.5	(21.8)	4,183.7	4,154.9	(28.8)	4,328.4	4,344.4	16.1	4,533.7	4,720.4
	Business Support												
16	Net Assets in Service	12.1 L12	1,626.6	1,484.7	(141.9)	1,713.8	1,577.3	(136.5)	1,719.0	1,548.1	(171.0)	1,609.3	1,617.8
17	Net Contributions		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Total		1,626.6	1,484.7	(141.9)	1,713.8	1,577.3	(136.5)	1,719.0	1,548.1	(171.0)	1,609.3	1,617.8
19	Mid-Year		1,530.8	1,459.8	(70.9)	1,670.2	1,531.0	(139.2)	1,716.4	1,562.7	(153.7)	1,578.7	1,613.6
	Total												
20	Net Assets in Service	12.0 L13	20,223.9	19,944.3	(279.6)	20,882.0	20,654.8	(227.2)	22,402.1	23,512.9	1,110.7	23,977.9	24,487.3
21	Net Contributions	11.0 L38	(1,613.2)	(1,664.5)	(51.3)	(1,661.9)	(1,769.5)	(107.6)	(1,716.1)	(1,864.3)	(148.1)	(1,966.9)	(2,056.8)
22	Net DSM	2.2 L6	931.8	915.6	(16.3)	954.6	902.5	(52.1)	979.7	927.1	(52.6)	932.0	949.7
23	Total		19,542.5	19,195.4	(347.1)	20,174.7	19,787.8	(386.9)	21,665.7	22,575.7	910.0	22,943.0	23,380.3
24	Mid-Year		19,077.8	18,904.2	(173.6)	19,858.6	19,491.6	(367.0)	20,920.2	21,181.7	261.5	22,759.4	23,161.6
	Portion of Rate Base												
25	Generation		41.9%	41.6%	-0.3%	41.9%	41.3%	-0.6%	43.1%	44.2%	1.1%	46.6%	46.5%
26	Transmission		35.2%	35.5%	0.3%	35.1%	35.6%	0.4%	34.4%	33.7%	-0.7%	32.0%	31.6%
27	Distribution		23.0%	23.0%	0.0%	23.0%	23.1%	0.1%	22.5%	22.1%	-0.4%	21.4%	21.9%
28	Total		100.0%	100.0%	0.0%	100.0%	100.0%	0.0%	100.0%	100.0%	0.0%	100.0%	100.0%

Contributions
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Contributions in Aid - Generation												
1	Gross Contns - Beginning of Year		9.8	9.8	0.0	9.8	9.5	(0.3)	9.7	9.5	(0.3)	9.5	9.5
2	Additions		0.0	(0.3)	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Retirements & Transfers		0.0	0.0	0.0	(0.1)	(0.0)	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)
4	Gross Contns - End of Year		9.8	9.5	(0.3)	9.7	9.5	(0.3)	9.7	9.5	(0.2)	9.5	9.5
5	Accum Amort - Beginning of Year		6.4	6.4	0.0	6.7	6.7	0.0	7.0	7.0	0.0	7.3	7.5
6	Amortization		0.3	0.3	0.0	0.3	0.3	0.0	0.3	0.3	(0.0)	0.3	0.2
7	Retirements & Transfers		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Accum Amort - End of Year		6.7	6.7	0.0	7.0	7.0	0.0	7.3	7.3	0.0	7.5	7.8
9	Net Contributions - End of Year		3.1	2.8	(0.3)	2.8	2.5	(0.3)	2.4	2.2	(0.2)	1.9	1.7
	Contributions in Aid - Transmission												
10	Gross Contns - Beginning of Year		638.0	638.0	0.0	647.7	653.7	6.0	668.9	667.0	(1.8)	684.0	707.6
11	Additions		9.8	15.8	6.0	21.8	15.6	(6.2)	26.2	17.1	(9.1)	23.7	14.8
12	Retirements & Transfers		(0.1)	(0.1)	0.0	(0.6)	(2.3)	(1.7)	(0.7)	(0.1)	0.5	(0.1)	(0.2)
13	Gross Contns - End of Year		647.7	653.7	6.0	668.9	667.0	(1.8)	694.4	684.0	(10.4)	707.6	722.2
14	Accum Amort - Beginning of Year		104.0	104.0	0.0	117.4	117.4	(0.0)	131.0	129.5	(1.5)	143.9	158.6
15	Amortization		13.4	13.5	0.1	13.6	14.0	0.4	13.7	14.4	0.7	14.7	15.1
16	Retirements & Transfers		0.0	(0.1)	(0.1)	0.0	(1.9)	(1.9)	0.0	0.0	0.0	0.0	0.0
17	Accum Amort - End of Year		117.4	117.4	(0.0)	131.0	129.5	(1.5)	144.8	143.9	(0.8)	158.6	173.7
18	Net Contributions - End of Year		530.3	536.3	6.1	537.8	537.5	(0.3)	549.6	540.1	(9.6)	549.0	548.5
	Contributions in Aid - Distribution												
19	Gross Contns - Beginning of Year		1,700.1	1,700.1	0.0	1,773.3	1,817.9	44.6	1,846.5	1,948.8	102.2	2,074.5	2,204.3
20	Additions		76.6	122.9	46.3	78.4	140.6	62.2	80.3	129.8	49.5	134.0	133.7
21	Retirements & Transfers		(3.4)	(5.1)	(1.7)	(5.1)	(9.7)	(4.6)	(5.6)	(4.0)	1.5	(4.2)	(4.4)
22	Gross Contns - End of Year		1,773.3	1,817.9	44.6	1,846.5	1,948.8	102.2	1,921.3	2,074.5	153.3	2,204.3	2,333.7
23	Accum Amort - Beginning of Year		660.8	660.8	0.0	693.4	692.5	(1.0)	725.3	719.3	(5.9)	752.5	788.4
24	Amortization		33.3	33.4	0.1	35.1	35.4	0.3	36.9	38.1	1.3	40.9	43.8
25	Amortization of Pre-1996 CIAC	2.2 L38	(0.7)	(0.7)	0.0	(3.2)	(3.2)	0.0	(4.9)	(4.9)	0.0	(5.1)	(5.1)
26	Retirements & Transfers		0.0	(1.1)	(1.1)	0.0	(5.3)	(5.3)	0.0	0.0	0.0	0.0	0.0
27	Accum Amort - End of Year		693.4	692.5	(1.0)	725.3	719.3	(5.9)	757.2	752.5	(4.7)	788.4	827.1
28	Net Contributions - End of Year		1,079.8	1,125.4	45.6	1,121.3	1,229.4	108.2	1,164.1	1,322.0	157.9	1,416.0	1,506.6
	Contributions in Aid - Total												
29	Gross Contns - Beginning of Year		2,347.8	2,347.8	0.0	2,430.7	2,481.1	50.3	2,525.1	2,625.3	100.1	2,768.0	2,921.4
30	Additions		86.4	138.4	52.0	100.2	156.2	56.1	106.4	146.9	40.4	157.8	148.5
31	Retirements & Transfers		(3.5)	(5.2)	(1.7)	(5.8)	(12.0)	(6.3)	(6.2)	(4.2)	2.1	(4.3)	(4.5)
32	Gross Contns - End of Year		2,430.7	2,481.1	50.3	2,525.1	2,625.3	100.1	2,625.3	2,768.0	142.6	2,921.4	3,065.3
33	Accum Amort - Beginning of Year		771.1	771.1	0.0	817.5	816.5	(1.0)	863.3	855.8	(7.4)	903.7	954.5
34	Amortization		47.1	47.3	0.2	49.0	49.7	0.7	50.9	52.8	1.9	55.9	59.2
35	Amortization of Pre-96 CIAC		(0.7)	(0.7)	0.0	(3.2)	(3.2)	0.0	(4.9)	(4.9)	0.0	(5.1)	(5.1)
36	Retirements & Transfers		0.0	(1.2)	(1.2)	0.0	(7.2)	(7.2)	0.0	0.0	0.0	0.0	0.0
37	Accum Amort - End of Year		817.5	816.5	(1.0)	863.3	855.8	(7.4)	909.2	903.7	(5.5)	954.5	1,008.6
38	Net Contributions - End of Year		1,613.2	1,664.5	51.3	1,661.9	1,769.5	107.6	1,716.1	1,864.3	148.1	1,966.9	2,056.8

Assets - Total (Excluding DSM and IPP Capital Leases)
($ million)

			F2017			F2018			F2019			F2020	F2021
		Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Forecast	Diff	Plan	Plan
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Gross Assets in Service												
1	Opening Balance		22,245.4	22,245.4	0.0	23,944.1	23,579.6	(364.5)	25,393.9	25,029.3	(364.6)	28,735.9	30,083.1
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L21	1,737.6	1,468.6	(269.0)	1,489.9	1,543.7	53.8	2,387.8	3,749.3	1,361.5	1,391.0	1,459.0
4	Retirements & Transfers		(38.9)	(134.3)	(95.5)	(40.1)	(94.0)	(53.9)	(39.7)	(42.7)	(3.1)	(43.9)	(46.8)
5	Closing Balance		23,944.1	23,579.6	(364.5)	25,393.9	25,029.3	(364.6)	27,742.1	28,735.9	993.8	30,083.1	31,495.3
	Accumulated Amortization												
6	Opening Balance		2,962.7	2,962.7	0.0	3,720.3	3,635.3	(84.9)	4,512.0	4,374.6	(137.4)	5,223.1	6,105.2
7	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.1)	0.0	0.0
8	Amortization on Existing Assets		730.4	730.4	0.0	711.1	711.0	(0.1)	681.0	679.7	(1.2)	853.5	822.1
9	Amortization on Additions	13.0 L35	27.1	25.1	(2.0)	80.5	81.2	0.7	147.0	168.9	21.8	28.6	80.7
10	Accelerated Amort on Burrard		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Retirements & Transfers		0.0	(82.9)	(82.9)	0.0	(53.0)	(53.0)	0.0	0.0	0.0	0.0	0.0
12	Closing Balance		3,720.3	3,635.3	(84.9)	4,512.0	4,374.6	(137.4)	5,340.0	5,223.1	(116.9)	6,105.2	7,008.0
13	**Net Assets in Service (Year-End)**		20,223.9	19,944.3	(279.6)	20,882.0	20,654.8	(227.2)	22,402.1	23,512.9	1,110.7	23,977.9	24,487.3

Assets - Business Support
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Gross Assets in Service												
1	Opening Balance		2,036.1	2,036.1	0.0	2,396.1	2,203.6	(192.6)	2,659.6	2,457.2	(202.3)	2,617.6	2,864.5
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L39	360.2	222.0	(138.3)	263.8	283.5	19.7	183.8	165.6	(18.1)	252.5	202.5
4	Retirements & Transfers		(0.3)	(54.6)	(54.3)	(0.3)	(29.8)	(29.5)	(0.5)	(5.3)	(4.8)	(5.5)	(5.6)
5	Closing Balance		2,396.1	2,203.6	(192.6)	2,659.6	2,457.2	(202.3)	2,842.8	2,617.6	(225.2)	2,864.5	3,061.4
	Accumulated Amortization												
6	Opening Balance		601.1	601.1	0.0	769.6	718.9	(50.7)	945.8	880.0	(65.8)	1,069.5	1,255.2
7	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8	1.8	0.0	0.0
8	Amortization on Existing Assets		159.3	159.3	0.0	147.6	157.7	10.1	128.1	141.8	13.7	169.8	147.0
9	Amortization on Additions	13.0 L44	9.2	9.3	0.1	28.7	28.1	(0.6)	49.9	45.9	(4.0)	15.9	41.4
10	Retirements & Transfers		0.0	(50.8)	(50.8)	0.0	(24.7)	(24.7)	0.0	0.0	0.0	0.0	0.0
11	Closing Balance		769.6	718.9	(50.7)	945.8	880.0	(65.8)	1,123.8	1,069.5	(54.3)	1,255.2	1,443.6
12	**Net Assets in Service (Year-End)**		1,626.6	1,484.7	(141.9)	1,713.8	1,577.3	(136.5)	1,719.0	1,548.1	(171.0)	1,609.3	1,617.8

Assets - Generation
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Gross Assets in Service												
1	Opening Balance		7,249.3	7,249.3	0.0	7,758.6	7,561.3	(197.3)	8,141.9	7,955.0	(186.9)	10,473.6	10,812.0
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L36	513.1	342.7	(170.4)	387.2	407.2	20.0	1,332.3	2,522.9	1,190.6	342.6	486.3
4	Retirements & Transfers		(3.7)	(30.6)	(26.9)	(3.8)	(13.5)	(9.7)	(3.6)	(4.3)	(0.7)	(4.1)	(4.4)
5	Closing Balance		7,758.6	7,561.3	(197.3)	8,141.9	7,955.0	(186.9)	9,470.6	10,473.6	1,003.0	10,812.0	11,293.9
	Accumulated Amortization												
6	Opening Balance		880.6	880.6	0.0	1,078.6	1,060.1	(18.5)	1,286.9	1,249.0	(37.8)	1,482.6	1,739.6
7	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.3)	(1.3)	0.0	0.0
8	Amortization on Existing Assets		190.9	191.0	0.0	188.7	182.6	(6.1)	183.4	176.8	(6.6)	252.9	249.7
9	Amortization on Additions	13.0 L41	7.1	4.9	(2.2)	19.6	16.2	(3.4)	43.3	58.1	14.8	4.1	13.1
10	Accelerated Amort on Burrard		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Retirements & Transfers		0.0	(16.4)	(16.4)	0.0	(9.8)	(9.8)	0.0	0.0	0.0	0.0	0.0
12	Closing Balance		1,078.6	1,060.1	(18.5)	1,286.9	1,249.0	(37.8)	1,513.5	1,482.6	(31.0)	1,739.6	2,002.4
13	**Net Assets in Service (Year-End)**		6,680.0	6,501.3	(178.7)	6,855.1	6,706.0	(149.1)	7,957.1	8,991.0	1,034.0	9,072.4	9,291.5

Assets - Transmission
($ million)

Line	Column	Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Gross Assets in Service												
1	Opening Balance		7,226.1	7,226.1	0.0	7,707.8	7,695.0	(12.8)	8,137.1	8,086.0	(51.1)	8,612.9	8,899.7
2	Adjustment to Opening Balance		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**0.0**
3	Capital Additions	13.0 L37	492.3	482.9	(9.4)	439.7	407.6	(32.2)	458.8	533.3	74.6	293.8	229.5
4	Retirements & Transfers		**(10.6)**	**(14.0)**	(3.4)	**(10.5)**	**(16.6)**	(6.1)	**(8.8)**	**(6.5)**	2.3	**(7.0)**	**(7.3)**
5	Closing Balance		7,707.8	7,695.0	(12.8)	8,137.1	8,086.0	(51.1)	8,587.1	8,612.9	25.8	8,899.7	9,121.9
	Accumulated Amortization												
6	Opening Balance		730.6	730.6	0.0	936.4	931.0	(5.4)	1,152.3	1,139.7	(12.6)	1,362.7	1,592.5
7	Adjustment to Opening Balance		**0.0**	**0.0**	0.0	**0.0**	**0.0**	0.0	**0.0**	**(0.7)**	(0.7)	**0.0**	**0.0**
8	Amortization on Existing Assets		**199.3**	**200.7**	1.4	**197.4**	**195.9**	(1.5)	**195.2**	**188.8**	(6.4)	**227.3**	**224.2**
9	Amortization on Additions	13.0 L42	6.4	6.1	(0.3)	18.6	20.4	1.8	30.4	34.9	4.6	2.5	7.7
10	Retirements & Transfers		**0.0**	**(6.5)**	(6.5)	**0.0**	**(7.5)**	(7.5)	**0.0**	**0.0**	0.0	**0.0**	**0.0**
11	Closing Balance		936.4	931.0	(5.4)	1,152.3	1,139.7	(12.6)	1,377.9	1,362.7	(15.2)	1,592.5	1,824.4
12	**Net Assets in Service (Year-End)**		6,771.5	6,764.0	(7.4)	6,984.7	6,946.3	(38.4)	7,209.1	7,250.2	41.0	7,307.2	7,297.6

Assets - Distribution
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Gross Assets in Service												
1	Opening Balance		5,733.8	5,733.8	0.0	6,081.6	6,119.7	38.2	6,455.4	6,531.0	75.7	7,031.9	7,506.8
2	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Capital Additions	13.0 L38	372.1	421.1	49.0	399.3	445.5	46.2	413.0	527.5	114.5	502.2	540.7
4	Retirements & Transfers		(24.3)	(35.1)	(10.8)	(25.5)	(34.2)	(8.7)	(26.8)	(26.7)	0.1	(27.2)	(29.5)
5	Closing Balance		6,081.6	6,119.7	38.2	6,455.4	6,531.0	75.7	6,841.6	7,031.9	190.2	7,506.8	8,018.0
	Accumulated Amortization												
6	Opening Balance		750.4	750.4	0.0	935.8	925.4	(10.3)	1,126.9	1,105.8	(21.1)	1,308.2	1,517.9
7	Adjustment to Opening Balance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.0
8	Amortization on Existing Assets		180.9	179.5	(1.4)	177.5	174.8	(2.6)	174.3	172.3	(2.0)	203.6	201.2
9	Amortization on Additions	13.0 L43	4.5	4.8	0.3	13.7	16.6	2.9	23.5	29.9	6.5	6.0	18.5
10	Retirements & Transfers		0.0	(9.3)	(9.3)	0.0	(11.0)	(11.0)	0.0	0.0	0.0	0.0	0.0
11	Closing Balance		935.8	925.4	(10.3)	1,126.9	1,105.8	(21.1)	1,324.7	1,308.2	(16.4)	1,517.9	1,737.7
12	**Net Assets in Service (Year-End)**		5,145.8	5,194.3	48.5	5,328.4	5,425.2	96.8	5,516.9	5,723.6	206.7	5,988.9	6,280.4

Capital Expenditures and Additions
($ million)

Line	Reference / Column	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Capital Expenditures											
1	Generation Growth	20.0	21.2	1.3	2.4	10.2	7.8	0.7	4.0	3.3	3.2	0.0
2	Generation - Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,219.5	1,219.5	0.0	0.0
3	Generation Sustaining	530.0	563.6	33.6	534.1	534.0	(0.1)	424.3	365.9	(58.4)	341.8	435.5
4	Transmission Growth	262.0	247.4	(14.6)	222.0	280.5	58.5	192.7	223.7	31.0	185.0	198.9
5	Transmission Sustaining	255.5	268.1	12.5	326.3	218.3	(108.0)	373.9	209.1	(164.9)	222.6	286.5
6	Distribution Growth	224.7	226.0	1.2	233.4	287.6	54.2	209.5	305.8	96.3	299.9	284.6
7	Distribution Sustaining	185.0	224.5	39.5	160.1	235.2	75.1	187.6	190.9	3.3	187.6	176.9
8	Site C Project	742.5	662.7	(79.8)	716.5	704.8	(11.7)	829.2	1,186.8	357.6	1,530.0	1,535.5
9	Technology	83.9	76.5	(7.3)	93.4	71.2	(22.2)	78.8	95.6	16.8	95.6	56.0
10	Properties	95.7	86.6	(9.1)	75.0	63.5	(11.5)	88.3	43.5	(44.8)	58.9	55.3
11	Fleet & Other	204.7	58.9	(145.8)	48.6	59.6	11.0	39.6	67.4	27.9	63.6	75.1
12	Total	2,603.9	2,435.5	(168.4)	2,411.9	2,464.9	53.0	2,424.6	3,912.1	1,487.5	2,988.3	3,104.2
	Total Capital Additions											
13	Generation	513.1	342.7	(170.4)	387.2	407.2	20.0	1,332.3	1,303.4	(28.9)	314.7	296.9
14	Generation - Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,219.5	1,219.5	0.0	0.0
15	Transmission	492.3	482.9	(9.4)	439.7	407.6	(32.2)	458.8	533.3	74.6	293.8	229.5
16	Distribution	372.1	421.1	49.0	399.3	445.5	46.2	413.0	527.5	114.5	502.2	540.7
17	Site C Project	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.9	189.4
18	Technology	81.6	81.6	0.0	91.1	97.2	6.1	112.6	67.1	(45.5)	147.6	75.5
19	Properties	68.3	54.8	(13.5)	118.2	126.9	8.7	25.5	28.7	3.2	39.9	55.6
20	Fleet & Other	210.3	85.6	(124.8)	54.5	59.4	4.9	45.7	69.8	24.1	65.0	71.3
21	Total	1,737.6	1,468.6	(269.0)	1,489.9	1,543.7	53.8	2,387.8	3,749.3	1,361.5	1,391.0	1,459.0
	Unfinished Construction											
22	Beginning of Year	2,460.8	2,460.8	0.0	3,327.1	3,412.9	85.8	4,249.1	4,306.8	57.8	4,457.9	6,045.4
23	Adjustments	0.0	(14.8)	(14.8)	0.0	(27.3)	(27.3)	0.0	(11.7)	(11.7)	(9.9)	(9.7)
24	Change in Unfinished	866.3	966.9	100.6	921.9	921.2	(0.8)	36.8	162.8	126.0	1,597.4	1,645.2
25	End of Year	3,327.1	3,412.9	85.8	4,249.1	4,306.8	57.8	4,285.8	4,457.9	172.1	6,045.4	7,680.9
26	Mid-Year Balance	2,894.0	2,936.9	42.9	3,788.1	3,859.9	71.8	4,267.5	4,382.4	114.9	5,251.6	6,863.1
	Amortization on Additions											
27	Generation	7.1	4.9	(2.2)	19.6	16.2	(3.4)	43.3	36.1	(7.2)	3.9	11.4
28	Generation - Waneta 2/3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22.0	22.0	0.0	0.0
29	Transmission	6.4	6.1	(0.3)	18.6	20.4	1.8	30.4	34.9	4.6	2.5	7.7
30	Distribution	4.5	4.8	0.3	13.7	16.6	2.9	23.5	29.9	6.5	6.0	18.5
31	Site C Project	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.7
32	Technology	6.5	5.9	(0.6)	20.3	19.5	(0.8)	36.6	33.2	(3.4)	13.6	34.0
33	Properties	1.2	0.7	(0.5)	4.6	2.8	(1.8)	7.2	4.7	(2.5)	0.7	2.5
34	Fleet & Other	1.4	2.7	1.3	3.9	5.9	2.0	6.1	8.0	1.9	1.7	4.9
35	Total	27.1	25.1	(2.0)	80.5	81.2	0.7	147.0	168.9	21.8	28.6	80.7
	Summary of Additions											
36	Generation	513.1	342.7	(170.4)	387.2	407.2	20.0	1,332.3	2,522.9	1,190.6	342.6	486.3
37	Transmission	492.3	482.9	(9.4)	439.7	407.6	(32.2)	458.8	533.3	74.6	293.8	229.5
38	Distribution	372.1	421.1	49.0	399.3	445.5	46.2	413.0	527.5	114.5	502.2	540.7
39	Business Support	360.2	222.0	(138.3)	263.8	283.5	19.7	183.8	165.6	(18.1)	252.5	202.5
40	Total	1,737.6	1,468.6	(269.0)	1,489.9	1,543.7	53.8	2,387.8	3,749.3	1,361.5	1,391.0	1,459.0
	Summary of Amortization on Additions											
41	Generation	7.1	4.9	(2.2)	19.6	16.2	(3.4)	43.3	58.1	14.8	4.1	13.1
42	Transmission	6.4	6.1	(0.3)	18.6	20.4	1.8	30.4	34.9	4.6	2.5	7.7
43	Distribution	4.5	4.8	0.3	13.7	16.6	2.9	23.5	29.9	6.5	6.0	18.5
44	Business Support	9.2	9.3	0.1	28.7	28.1	(0.6)	49.9	45.9	(4.0)	15.9	41.4
45	Total	27.1	25.1	(2.0)	80.5	81.2	0.7	147.0	168.9	21.8	28.6	80.7
	Composite Depreciation Rate											
46	Generation	2.76%			2.78%			2.76%			2.45%	2.46%
47	Transmission	2.68%			2.60%			2.67%			1.70%	2.31%
48	Distribution	2.40%			2.40%			2.40%			2.40%	2.40%
49	Site C Project	0.00%			0.00%			0.00%			1.95%	1.27%
50	Technology	15.98%			15.84%			16.26%			18.38%	18.22%
51	Properties	3.65%			3.50%			4.32%			3.59%	3.73%
52	Fleet & Other	5.03%			4.85%			4.57%			5.08%	4.55%

Domestic Energy Sales and Revenue

Line		F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Reference Column	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Domestic Energy Sales (GWh)											
1	Residential	18,036	18,068	31	18,112	18,150	39	18,250	18,049	(201)	18,258	18,330
2	Light Industrial and Commercial	18,832	18,968	136	18,785	18,874	89	18,899	18,976	78	18,973	19,030
3	Large Industrial	13,323	13,176	(147)	13,184	13,433	249	13,743	14,000	257	14,702	14,243
4	Irrigation	67	80	13	67	79	12	67	77	10	79	79
5	Street Lighting	234	232	(3)	237	229	(8)	239	232	(7)	232	232
6	New Westminster & Tongass	476	464	(12)	484	466	(18)	491	465	(26)	471	472
7	Fortis	524	589	65	521	551	31	527	492	(35)	542	555
8	Seattle City Light	310	318	8	310	312	2	310	310	(1)	310	310
9	Liquefied Natural Gas	57	0	(57)	139	6	(132)	139	4	(135)	0	0
10	Total	51,860	51,895	35	51,838	52,102	264	52,664	52,604	(60)	53,567	53,253
	Domestic Revenues ($ million)											
11	Residential	1,914.8	1,916.2	1.4	1,991.4	1,996.8	5.4	2,067.9	2,037.8	(30.1)	2,072.8	2,082.0
12	Light Industrial and Commercial	1,703.2	1,714.7	11.5	1,758.4	1,770.6	12.2	1,821.9	1,832.5	10.6	1,835.9	1,840.8
13	Large Industrial	744.2	732.6	(11.6)	763.9	771.2	7.2	830.0	840.7	10.7	895.3	874.6
14	Irrigation	4.7	6.0	1.3	4.9	5.4	0.5	5.0	6.2	1.2	5.9	5.9
15	Street Lighting	39.7	39.2	(0.5)	41.5	40.6	(0.9)	43.2	42.2	(1.1)	42.4	42.5
16	New Westminster & Tongass	28.4	27.7	(0.7)	29.9	28.9	(1.1)	31.4	29.7	(1.6)	30.3	30.3
17	Fortis	34.9	36.2	1.3	36.0	35.6	(0.4)	37.4	34.2	(3.2)	36.9	37.5
18	Seattle City Light	12.6	13.0	0.5	12.0	11.9	(0.1)	12.1	28.6	16.5	28.6	28.7
19	Liquefied Natural Gas	4.4	0.4	(4.0)	10.7	1.3	(9.4)	10.9	0.3	(10.6)	0.0	0.0
20	Subtotal	4,486.8	4,486.0	(0.8)	4,648.9	4,662.3	13.5	4,859.8	4,852.2	(7.5)	4,948.2	4,942.4
21	Revenue from Deferral Rider	223.5	223.7	0.2	231.3	233.2	1.9	241.8	241.2	(0.7)	0.0	0.0
22	Total	4,710.3	4,709.7	(0.6)	4,880.2	4,895.5	15.3	5,101.6	5,093.4	(8.2)	4,948.2	4,942.4
23	**Deferral Account Rate Rider**	5.0%	5.0%		5.0%	5.0%		5.0%	5.0%		0.0%	0.0%
	Average Revenues ($/MWh)											
24	Residential	106.2	106.1	(0.1)	110.0	110.0	0.1	113.3	112.9	(0.4)	113.5	113.6
25	Light Industrial and Commercial	90.4	90.4	(0.0)	93.6	93.8	0.2	96.4	96.6	0.2	96.8	96.7
26	Large Industrial	55.9	55.6	(0.3)	57.9	57.4	(0.5)	60.4	60.1	(0.3)	60.9	61.4
27	Irrigation	70.2	75.0	4.8	72.7	67.6	(5.1)	74.8	80.3	5.5	74.3	74.3
28	Street Lighting	169.7	169.5	(0.2)	175.6	177.5	1.9	180.9	181.9	1.0	182.9	182.9
29	New Westminster & Tongass	59.7	59.7	(0.0)	61.8	61.9	0.1	63.9	64.0	0.1	64.4	64.2
30	Fortis	66.7	61.4	(5.2)	69.2	64.6	(4.6)	71.0	69.6	(1.3)	68.0	67.5
31	Seattle City Light	40.5	41.0	0.6	38.8	38.2	(0.6)	38.9	92.2	53.3	92.3	92.4
32	Liquefied Natural Gas	76.2	1,080.8	1,004.5	77.2	203.3	126.1	78.8	78.4	(0.4)	-	-
33	Total (Excluding Misc Rev)	90.8	90.8	(0.1)	94.1	94.0	(0.2)	96.9	96.8	(0.0)	92.4	92.8

Miscellaneous Revenue
($ million)

Line		Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Generation												
1	Amortization of Contributions	11.0 L6	0.3	0.3	0.0	0.3	0.3	0.0	0.3	0.3	(0.0)	0.3	0.2
2	Other		1.7	2.0	0.3	1.6	1.6	0.0	1.6	1.8	0.3	1.6	1.7
3	Total		2.0	2.3	0.3	1.8	1.9	0.0	1.9	2.1	0.2	1.9	1.9
	Transmission												
4	External OATT	3.4 L73	14.0	11.8	(2.2)	13.8	11.4	(2.4)	14.0	11.6	(2.5)	15.4	15.4
5	FortisBC Wheeling Agreement		4.7	4.8	0.1	4.9	5.1	0.2	5.0	5.2	0.2	5.2	5.3
6	Secondary Revenue		5.1	7.6	2.5	5.1	7.5	2.4	5.0	6.0	1.0	6.0	6.2
7	Interconnections		3.0	3.6	0.6	1.9	2.9	1.0	1.9	1.9	0.0	2.2	2.2
8	Amortization of Contributions	11.0 L15:L16-L12	13.6	13.5	(0.0)	14.2	14.4	0.2	14.4	14.6	0.2	14.8	15.3
9	NTL Supplemental Charge		2.7	2.7	(0.0)	2.0	2.0	(0.0)	2.0	2.3	0.2	2.3	2.3
10	Total		43.1	44.1	0.9	41.9	43.3	1.4	42.4	41.5	(0.8)	45.9	46.6
	Distribution												
11	Secondary Use Revenue & Other		13.6	15.3	1.6	13.7	15.9	2.3	13.8	14.4	0.6	14.1	14.1
12	Amortization of Contributions	11.0 L24:L26-L21	36.7	37.5	0.7	40.2	39.8	(0.4)	42.4	42.1	(0.3)	45.1	48.2
13	Total		50.4	52.7	2.3	53.9	55.7	1.9	56.2	56.5	0.4	59.2	62.3
	Customer Care												
14	Meter/Trans Rents & Power Factor Surcharges		12.7	12.3	(0.4)	13.1	12.7	(0.4)	13.4	14.3	0.9	14.6	14.9
15	Smart Metering & Infrastructure Impact		4.6	4.5	(0.1)	3.8	3.8	0.0	3.0	3.0	0.0	2.1	1.7
16	Diversion Net Recoveries		0.4	0.5	0.1	0.1	0.4	0.3	0.1	0.2	0.1	0.1	0.1
17	Other Operating Recoveries		4.7	4.3	(0.4)	4.7	4.4	(0.3)	4.8	4.5	(0.3)	4.5	4.6
18	Customer Crisis Fund Rider Revenue		0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	4.0	5.3	5.3
19	Other		2.4	3.3	0.9	2.4	2.1	(0.3)	2.4	2.9	0.5	3.0	3.0
	Waneta 2/3												
20	Lease revenue from Teck				0.0			0.0			0.0	75.2	76.7
21	Teck portion of operating costs				0.0			0.0	0.0	3.8	3.8	5.7	5.9
22	Teck portion of water rentals				0.0			0.0	0.0	2.4	2.4	3.5	3.7
23	Teck portion of property taxes				0.0			0.0	0.0	0.1	0.1	0.6	0.6
24	Subtotal		0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.4	6.4	84.9	86.9
25	Total		24.8	24.9	0.1	24.1	23.4	(0.7)	23.6	35.3	11.6	114.5	116.4
	Business Support												
26	Corporate General Rents		3.5	4.6	1.0	3.3	4.3	1.0	3.2	3.8	0.6	3.7	3.8
27	Late Payment Charges		6.9	7.1	0.2	7.1	7.6	0.5	7.2	7.7	0.5	7.9	8.1
28	MMBU Secondary Revenue		5.4	5.8	0.5	5.4	5.9	0.5	5.4	3.8	(1.6)	3.8	3.8
29	Other		1.0	2.0	1.0	0.8	1.6	0.8	0.8	0.8	0.1	0.7	0.7
30	Total		16.8	19.5	2.7	16.6	19.4	2.8	16.6	16.2	(0.4)	16.2	16.4

Miscellaneous Revenue
($ million)

			F2017			F2018			F2019			F2020	F2021
		Reference	RRA	Actual	Diff	RRA	Actual	Diff	RRA	Forecast	Diff	Plan	Plan
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
31	**Total Before Regulatory Accounts**		137.1	143.4	6.3	138.3	143.7	5.5	140.6	151.6	11.0	237.7	243.7

Miscellaneous Revenue
($ million)

Line	Reference / Column	F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Deferral Account Additions											
32	Waneta 2/3											
33	Lease revenue from Teck			0.0			0.0	0.0	50.6	50.6	0.0	0.0
34	Teck portion of capital expenditures			0.0			0.0	0.0	0.7	0.7	3.1	3.5
35	Subtotal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	51.3	51.3	3.1	3.5
	Regulatory Account Additions											
36	Smart Metering & Infrastructure Impact	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	Minimum Reconnection Charge	0.0	(0.3)	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	Subtotal	0.0	(0.3)	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	**Total Gross Miscellaneous Revenue**	137.1	143.1	6.0	138.3	143.7	5.5	140.6	202.9	62.3	240.8	247.2
40	**Transfers to NHDA**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(51.3)	(51.3)	(3.1)	(3.5)
41	**Transfers to Regulatory Accounts**	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	**Total Current Miscellaneous Revenue**	137.1	143.4	6.3	138.3	143.7	5.5	140.6	151.6	11.0	237.7	243.7

Full-Time Equivalents
(FTEs)

Line		F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column Reference	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Integrated Planning											
1	Energy Planning & Analytics	27	29	2	27	31	4	27	38	11	44	44
2	Dam Safety	35	34	(1)	35	34	(1)	35	37	2	37	37
3	Stations Asset Planning	51	51	1	51	49	(1)	51	46	(5)	59	59
4	Line Asset Planning	109	109	(0)	109	112	3	109	113	4	116	116
5	Interconnections and Shared Assets	40	36	(4)	40	43	3	40	47	7	47	47
6	Engineering	536	540	4	536	558	22	536	586	49	646	646
7	Business Unit Support	4	4	0	4	3	(1)	4	3	(1)	3	3
8	Total	802	804	2	802	830	28	802	870	68	952	952
	Capital Infrastructure Project Delivery											
9	Project Delivery	340	324	(16)	368	387	19	368	453	85	450	450
10	Indigenous Relations	47	57	10	47	59	12	47	68.5	21	69	69
11	Environment	83	86	3	83	90	7	83	89	6	94	94
12	Properties	106	110	4	106	114	8	106	124	18	123	123
13	Business Unit Support	3	3	0	3	3	(0)	3	3	0	3	3
14	Total	579	581	2	607	652	45	607	737	130	739	739
	Operations											
15	Program and Contract Management	213	205	(8)	217	206	(12)	217	221	4	228	228
16	Line Field Operations	844	838	(7)	844	856	12	844	931	86	938	938
17	Stations Field Operations	856	829	(27)	856	818	(38)	856	858	2	777	777
18	Distribution Design & Customer Connect	338	325	(14)	338	347	9	338	379	41	379	379
19	Construction Services	404	411	6	404	409	5	404	398	(6)	397	397
20	Generation System Operations	64	65	1	64	68	3	64	64	(0)	63	63
21	T&D System Operations	165	170	5	165	174	8	165	178	13	197	197
22	Business Unit Support	3	3	0	3	3	(0)	3	3	0	5	5
23	Total	2,889	2,845	(43)	2,893	2,880	(12)	2,893	3,033	140	2,984	2,984
	Safety											
24	Safety System and Assurance	52	48	(4)	52	49	(3)	52	52	(0)	52	52
25	Learning and Development	438	456	18	438	437	(2)	438	358	(80)	317	300
26	Field Safety Services	53	50	(3)	55	56	1	55	63	8	62	62
27	Security and Emergency Management	18	20	2	18	25	7	18	26	9	31	31
28	Business Unit Support	2	2	0	2	2	0	2	2	(0)	2	2
29	Total	563	576	13	565	568	3	565	501	(63)	464	447

Full-Time Equivalents (FTEs)

Line		F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
	Column	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Finance, Technology, Supply Chain											
30	Finance	188	194	6	188	196	8	188	204	16	206	206
31	Technology	176	186	10	191	226	35	202	263	61	269	269
32	Supply Chain	402	421	19	402	447	45	402	454	51	468	468
33	Business Unit Support	3	3	0	3	3	(0)	3	3	0	3	3
34	Total	769	805	35	784	871	87	795	924	129	946	946
	People, Customer, Corporate Affairs											
35	Human Resources	88	84	(4)	88	88	0	88	125	37	124	124
36	Customer Service	124	154	30	124	191	67	124	495	372	479	479
37	Conservation and Energy Management	114	110	(4)	112	112	1	112	116	4	116	116
38	Power Acquisitions and Contract Management	23	26	3	23	28	5	23	27	4	26	26
39	Communications and Community Engagement	86	94	7	86	95	9	86	107	22	107	107
40	Regulatory and Rates	28	23	(4)	27	26	(1)	27	28	1	28	28
41	Ethics and Merit Office	1	2	1	1	3	2	1	4	3	5	5
42	Smart Metering & Infrastructure	0	0	0	0	0	0	0	0	0	0	0
43	Business Unit Support	3	3	0	3	3	(0)	3	3	0	3	3
44	Total	467	497	30	463	545	82	463	906	443	887	887
	Other											
45	Office of the General Counsel	37	36	(1)	37	35	(2)	37	43	5	42	42
46	Office of the President and Chief Operating Officer	4	4	0	4	3	(1)	4	3	(1)	3	3.00
47	Site C Project	186	167	(18)	189	226	37	199	389	190	460	472
48	Independent Power Producer Capital Leases	0	0	0	0	0	0	0	0	0	0	0
49	Corporate Costs	0	0	0	0	0	0	0	0	0	0	0
50	Capitalized Costs	0	0	0	0	0	0	0	0	0	0	0
51	Total	227	208	(19)	231	264	34	241	434	194	505	516
52	**Total**	6,296	6,315	19	6,344	6,611	267	6,365	7,405	1,039	7,477	7,471

Full-Time Equivalents (FTEs)

Line		F2017 RRA	F2017 Actual	F2017 Diff	F2018 RRA	F2018 Actual	F2018 Diff	F2019 RRA	F2019 Forecast	F2019 Diff	F2020 Plan	F2021 Plan
Column	Reference	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10	11
	Summary											
53	Regular Hour FTEs (excl. Smart Metering & Infrastructure & Site C Project)	5,547	5,578	31	5,592	5,791	199	5,603	6,431	828	6,461	6,449
54	Smart Metering & Infrastructure (SMI)	0	0	0	0	0	0	0	0	0	0	0
55	Site C Project	174	157	(17)	177	212	36	182	357	175	422	431
56	Subtotal Regular Hour FTEs	5,721	5,735	15	5,769	6,004	235	5,785	6,789	1,003	6,884	6,880
57	Overtime Hour FTEs (excl. Smart Metering & Infrastructure & Site C Project)	563	570	6	563	593	30	563	585	22	556	551
58	Smart Metering & Infrastructure (OT Hour FTEs)	0	0	0	0	0	0	0	0	0	0	0
59	Site C Project (OT Hour FTEs)	12	10	(1)	12	14	1	17	31	14	38	41
60	Total	6,296	6,315	19	6,344	6,611	267	6,365	7,405	1,039	7,477	7,471
	Summary of FTE's by Function											
	Regular Hour FTEs											
61	Operating	3,656	3,747	91	3,666	3,859	193	3,669	4,243	574	4,250	4,247
62	Capital	1,910	1,829	(82)	1,951	1,983	32	1,964	2,381	416	2,470	2,469
63	Deferred	154	160	5	152	161	9	152	165	13	164	164
64	Total	5,721	5,735	15	5,769	6,004	235	5,785	6,789	1,003	6,884	6,880
	Overtime Hour FTEs											
65	Operating	216	336	120	215	350	135	215	231	16	220	219
66	Capital	359	243	(116)	360	256	(104)	365	385	21	373	373
67	Deferred	1	1	1	1	1	1	1	0	(0)	0	0
68	Total	575	580	5	575	607	32	580	616	36	593	592
	Total FTEs by Function											
69	Operating	3,872	4,082	211	3,881	4,209	328	3,884	4,474	590	4,470	4,466
70	Capital	2,269	2,072	(197)	2,311	2,239	(72)	2,329	2,766	437	2,843	2,841
71	Deferred	155	161	6	152	162	10	152	165	12	164	164
72	Total	6,296	6,315	19	6,344	6,611	267	6,365	7,405	1,039	7,477	7,471

BC Hydro
Power smart

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix B

Draft Orders

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2020 to Fiscal 2021 Revenue Requirements Application

BEFORE:
Commissioner
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On February 25, 2019, British Columbia Hydro and Power Authority (BC Hydro) filed its Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (Application) with the British Columbia Utilities Commission (BCUC) pursuant to sections 44.2, 58 to 61 and 99 of the *Utilities Commission Act* (Act) requesting, among other things,

   (i) effective April 1, 2019, a reduction of the Deferral Account Rate Rider (DARR) from 5 percent to 0 percent and an increase in rates by 6.85 percent, resulting in an average net bill increase of 1.76 percent;

   (ii) effective April 1, 2020, an increase in rates by 0.72 percent; and

   (iii) approval of the fiscal 2020 and fiscal 2021 OATT rates in Table 9-8 of the Application effective April 1, 2019 and April 1, 2020, respectively.

B. BC Hydro requested these changes be made effective on an interim basis, pending a final BCUC decision on the Application.

C. The BCUC has considered the Application and determines that approval of interim rates is warranted.

NOW THEREFORE pursuant to sections 58 to 61, 89 and 90 of the *Utilities Commission Act*, and for the reasons outlined in the decision issued concurrently with this order, the BCUC orders as follows:

1. The requested reduction of the DARR from 5 percent to 0 percent is approved on an interim basis, effective April 1, 2019.

.../2

2. The requested rate increases of 6.85 percent and 0.72 percent, to be applied as set out in Appendix EE of the Application, are approved on an interim basis effective April 1, 2019 and April 1, 2020, respectively.

3. The requested OATT rates for fiscal 2020 and fiscal 2021 as set out in Table 9-8 of the Application are approved on an interim basis effective April 1, 2019 and April 1, 2020, respectively.

4. The rate schedules set out in Appendix EE are accepted for filing.

5. The rates and OATT rates approved by this order will remain interim and subject to refund with interest at BC Hydro's weighted average cost of debt until further order of the BCUC.

6. BC Hydro must provide customers with notification of the interim rate increase as soon as is practicable.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment Options

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
P: 604.660.4700
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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2020 to Fiscal 2021 Revenue Requirements Application

BEFORE:
Commissioner
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On February 25, 2019, British Columbia Hydro and Power Authority (BC Hydro) filed its Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (Application) with the British Columbia Utilities Commission (BCUC) pursuant to sections 44.2, 58 to 61 and 99 of the *Utilities Commission Act* (Act) requesting, among other things,

   (i) effective April 1, 2019, a reduction of the Deferral Account Rate Rider (DARR) from 5 percent to 0 percent and an increase in rates by 6.85 percent, resulting in an average net bill increase of 1.76 percent;

   (ii) effective April 1, 2020, an increase in rates by 0.72 percent;

   (iii) approval of the fiscal 2020 and fiscal 2021 OATT rates in Table 9-8 of the Application effective April 1, 2019 and April 1, 2020, respectively; and

   (iv) acceptance of a demand-side management expenditure schedule of $207.1 million in fiscal 2020 and fiscal 2021 as set out in Table 10-1 of the Application.

B. On March XX, 2019, the BCUC issued Order No. G-XX-19 approving BC Hydro's request that the changes to the DARR and rates sought in the Application be approved on an interim basis effective April 1, 2019, pending a final BCUC decision on the Application.

C. On XX, 2019, the BCUC issued Order No. G-XX-19 establishing a regulatory timetable for the review of the Application.

D. [Other recitals as required.]

.../2

E. The BCUC has considered the Application and the evidence and submissions filed in the proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 44.2, 58 to 61 and 99 of the *Utilities Commission Act*, and for the reasons outlined in the decision issued concurrently with this order, the BCUC orders as follows:

1. The requested final reduction of the DARR from 5 percent to 0 percent is approved effective April 1, 2019.

2. The requested final rate increases of 6.85 percent and 0.72 percent, to be applied as set out in Appendix EE of the Application, are approved effective April 1, 2019 and April 1, 2020, respectively.

3. The following requested changes to deferral and regulatory accounts and the associated financial treatment are approved:
    a. Amortize into rates, over the fiscal 2020 to fiscal 2021 test period, the forecast fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts;
    b. Defer any variances related to the accounting for EPAs determined to be leases under International Financial Reporting Standard (IFRS) 16, which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account;
    c. Defer any variances between forecast and actual amounts related to the Biomass Energy Program, which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account;
    d. Continue to defer, on an annual and ongoing basis, any variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account, continue to apply interest to the balance of the account and recover the forecast interest charged to the account each year, and continue to recover the forecast account balance at the end of a test period over the next test period;
    e. Defer low-carbon electrification expenditures to the Demand-Side Management Regulatory Account;
    f. Remove the reference to the "Prescribed Standards" from the description of what may be deferred to the Site C Regulatory Account;
    g. Closure of the Capital Project Investigation Costs Regulatory Account at the end of fiscal 2021; and
    h. Closure of the Rate Smoothing Regulatory Account in fiscal 2020.

4. The requested depreciation rates for the Burrard synchronous condense facility, for new Water Rights, Infrastructure Rights and LED Streetlights asset classes and for three new asset classes for agreements recognized as leases under IFRS 16, *Leases* are approved on an ongoing basis.

5. The requested OATT rates for fiscal 2020 and fiscal 2021 in Table 9-8 of the Application are approved effective April 1, 2019 and April 1, 2020, respectively.

6. The requested demand side management (DSM) expenditure schedule of $207.1 million in fiscal 2020 and fiscal 2021 as set out in Table 10-1 of the Application is accepted.

7. The request for reconsideration of Directive 3 of the BCUC's Decision on BC Hydro's Fiscal 2017 to Fiscal 2019 Revenue Requirements Application which directs BC Hydro to file a certificate of public convenience and necessity (CPCN) application for the Northwest Substation Upgrade project is allowed, and Directive 3 is varied to no longer require BC Hydro to file a CPCN for the project.

8. The requested reconsideration is allowed with respect to the following directives, which are rescinded:
   a. Directive 61 of the BCUC's Decision on BC Hydro's Fiscal 2005 to Fiscal 2006 Revenue Requirements Application which directed that a prorated amount of costs from portfolio-level initiatives be added to the cost of each DSM program to assess cost effectiveness; and
   b. Directive 57 of the BCUC's Decision on BC Hydro's Fiscal 2009 to Fiscal 2010 Revenue Requirements Application which directed that BC Hydro revenue requirement applications filed after January 1, 2011 contain financial information that follows the Uniform System of Accounts.

9. BC Hydro is directed to comply with all other directives in the Decision accompanying this order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment Options

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

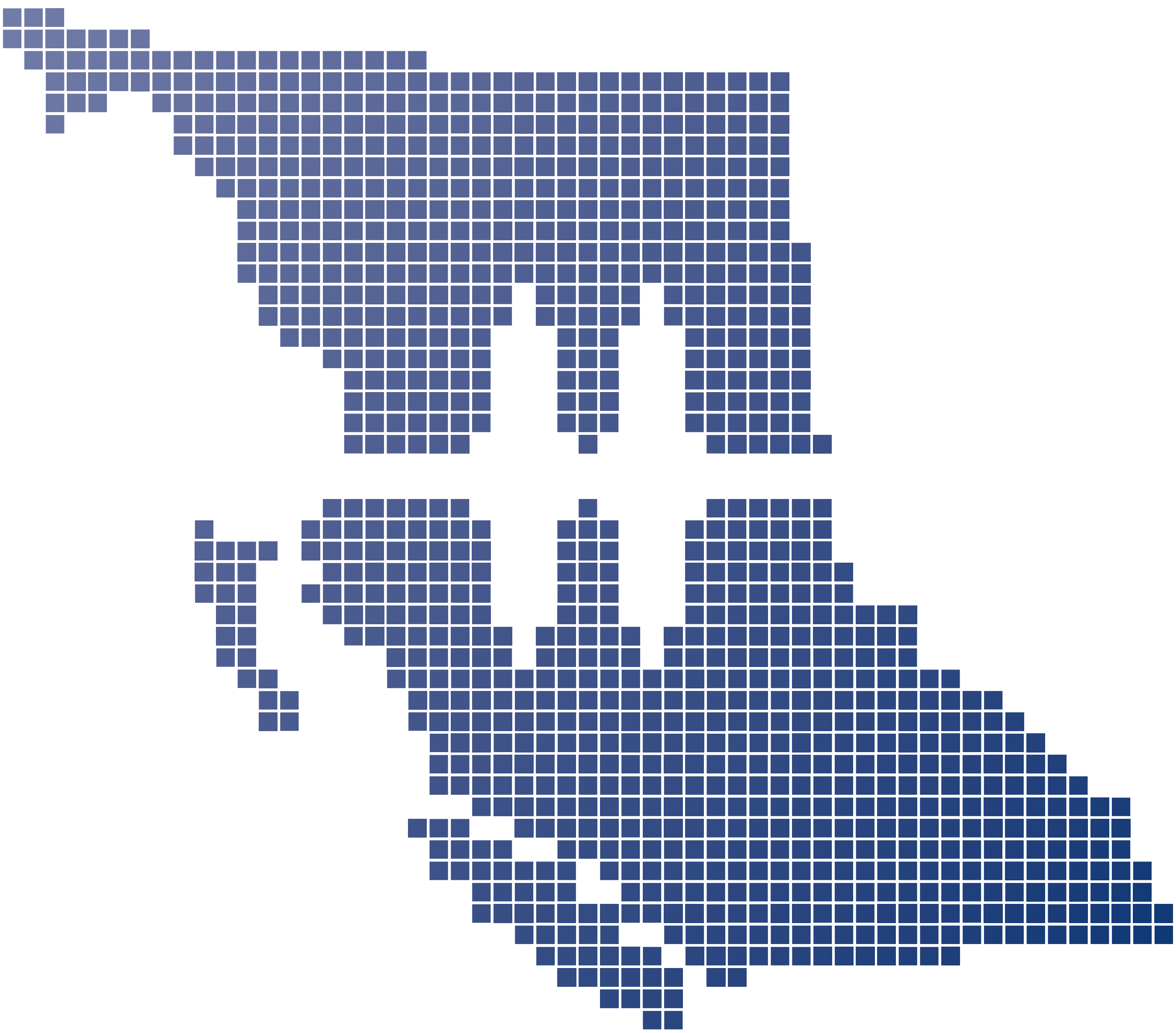
Appendix C

Comprehensive Review of BC Hydro

British Columbia

Ministry of Energy, Mines and Petroleum Resources

Comprehensive Review of BC Hydro: Phase 1 Final Report



Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Table of Contents

1. Executive Summary

To keep electricity rates affordable and position BC Hydro for future success, the BC government ("the government") launched a comprehensive, two-phased review (the Review) of BC Hydro, beginning in June 2018.

The Terms of Reference for Phase 1 of the Review are included as Appendix A. The first phase of the Review was conducted by the Ministry of Energy, Mines and Petroleum Resources, the Ministry of Finance and BC Hydro and is now complete, with two key outcomes:

- Enhanced regulatory oversight of BC Hydro; and
- A new five-year rates forecast that reflects cost and revenue strategies to keep rates affordable.

The purpose of this Phase 1 Final Report is to outline the work undertaken in Phase 1 and the details related to the two key outcomes above. This information will be of interest to the citizens of British Columbia and BC Hydro's customers, Indigenous Nations, communities, Independent Power Producers, as well as key stakeholders such as the Auditor General of British Columbia, the British Columbia Utilities Commission (BCUC) and other parties engaged in BC Hydro's regulatory processes. Key decisions related to Phase 1 are complete, and this Final Report explains how the outcomes are being implemented.

The Terms of Reference for Phase 2 will be finalized and made public in early 2019. Phase 2 is expected to focus on how the energy industry and markets are transforming, how to ensure BC Hydro's long-term sustainability with those transformations and BC Hydro's role in implementing electrification initiatives critical to the CleanBC plan, government's plan to reach its 2030 climate targets through reduction of greenhouse gas emissions in transportation, buildings and industry.

1.1 Enhancing Regulatory Oversight of BC Hydro

BC Hydro is in a unique position compared to other public utilities in B.C. As an electric utility, its mandate is to provide safe and reliable electricity services to its customers, under the oversight of the BCUC. As a provincial Crown corporation, it also has a role in implementing government policies. The two objectives are not always aligned, particularly in cases where implementing government policy may have costs for BC Hydro and its customers.

In recent years, the government exercised its authority under the *Utilities Commission Act* to direct BCUC decision-making and outcomes on a number of matters to achieve policy objectives, including the setting and capping of BC Hydro's rate increases for specific years covered by the 10 Year Rates Plan (April 1, 2014 to March 31, 2024) and directing certain outcomes related to BC Hydro's regulatory accounts. These measures have led to concerns from the B.C. Auditor General and others that the government's actions have unduly impacted the BCUC's role as the independent regulator of BC Hydro.

Phase 1 of the Review has resulted in a number of actions (please refer to Section 4 and Appendix D for further detail) that enhance the regulatory oversight of BC Hydro, while still enabling the government to advance its social, economic and environmental priorities:

- The government, has accepted a recommendation from the review that BC Hydro write off the entire balance forecast of BC Hydro's Rate Smoothing Regulatory Account in Fiscal 2019. BC Hydro will request the closure of the account in its F2020-F2021 Revenue Requirements Application, to be filed with the BCUC in February 2019. As part of the previous government's 2013 10 Year Rates Plan, the BCUC was directed by government to allow the account without the ability for the BCUC to provide appropriate oversight.
- The government has repealed a number of regulations that restricted the BCUC's decision-making in the past. Moving forward, this will enable the BCUC to review and make decisions on BC Hydro's costs, proposed rate increases and almost all regulatory accounts, programs and capital projects.
- The government intends to introduce legislation to restore the BCUC's authority to review and approve BC Hydro's Integrated Resource Plan (IRP). The IRP will be submitted to the BCUC by February 2021. This timing enables development of the IRP to be informed by Phase 2 of the Review and the CleanBC plan.
- The government intends to enable the BCUC to begin setting BC Hydro's allowed net income for rate-setting purposes, following a two-year transition period for Fiscal 2020[1] and Fiscal 2021, during which BC Hydro's current net income target of $712 million will remain in place.
- The government has changed the accounting rules that BC Hydro is required to follow. BC Hydro will fully adopt International Financial Reporting Standards (IFRS) for Fiscal 2019. IFRS is aligned with the Canadian Generally Accepted Accounting Principles. This change addresses a recommendation made by the Auditor General.

The changes to the regulatory framework, and other regulations required to implement the outcomes of Phase 1 of the Review, are summarized in Appendix C.

1 The fiscal years within this report start on April 1, and end on March 31 of the following year. As an example, "Fiscal 2020" refers to the fiscal year that starts April 1, 2019 and ends on March 31, 2020.

1.2 New Rates Forecast

The cumulative increase in bills for ratepayers is forecast to be 8.1% over the next five years (Fiscal 2020 through Fiscal 2024). This is approximately 40% lower than the 13.7% increase for the same period under the previous 2013 10 Year Rates Plan and more than 20% lower than the forecast rate of B.C. inflation for the period. Actual rate increases will be determined by the BCUC through future Revenue Requirements Applications.

Table 1: BC Hydro Five Year Rates Forecast

	Fiscal 2020 Apr 1, 2019 – Mar 31, 2020	Fiscal 2021 Apr 1, 2020 – Mar 31, 2021	Fiscal 2022 Apr 1, 2021 – Mar 31, 2022	Fiscal 2023 Apr 1, 2022 – Mar 31, 2023	Fiscal 2024 Apr 1, 2023 – Mar 31, 2024	Cumulative Five Years*
Current Rates Forecast – Annual Rate Increase before reducing the DARR	6.8%	0.7%	2.2%	0.0%	3.2%	n/a
Current Rates Forecast – Annual Bill Impact including reduction in DARR**	1.8%	0.7%	2.2%	0.0%	3.2%	8.1%
Previous Govt's 10 Year Rates Plan – Annual Bill Impact	2.6%	2.6%	2.6%	2.6%	2.6%	13.7%
Forecast BC Inflation	2.3%	2.0%	2.0%	2.0%	2.0%	10.7%

* *cumulative rates do not equal the sum of individual rate changes shown for each year due to the effect of compounding.*

** *after reducing the Deferral Account Rate Rider (**DARR**) from 5% to 0%, beginning in Fiscal 2020. Under the 2013 10 Year Rates Plan, the DARR was set at 5% indefinitely – it was expected to remain at 5% at least through Fiscal 2024. Going forward, the BCUC will now determine how the DARR is set and applied. This change is explained further in Section 4.1.3.*

As a result of the Review, and in order to achieve the forecast rate increases shown above, government and BC Hydro are taking a number of actions to keep rates affordable.

Write-off of Rate Smoothing Regulatory Account

The write-off of the Rate Smoothing Regulatory Account, noted in Section 1.1, will reduce BC Hydro's forecast overall regulatory account balance at the end of Fiscal 2019 by 24%, from $4.7 billion to $3.6 billion. Lowering the overall regulatory account balance means lowering the amount that would be otherwise recovered from ratepayers, thus reducing rate pressures over the next five years.

Energy Procurement

Recognizing that energy procurement is a major cost driver for BC Hydro, and that BC Hydro is currently forecast to be in energy surplus into the 2030s, Phase 1 of the Review assessed how energy procurement costs could be reduced. The primary areas where future costs can be managed are expiring biomass Electricity Purchase Agreements and the Standing

Offer Program, which is BC Hydro's only active procurement program for new Electricity Purchase Agreements.

The government and BC Hydro have worked together to develop a biomass energy strategy to address the expiry of Electricity Purchase Agreements for biomass projects in the next few years. As a result, BC Hydro intends to acquire up to 80%, in aggregate, of the historical energy deliveries received under biomass Electricity Purchase Agreements that are due to expire before March 31, 2022. The prices offered for the biomass energy will also be lower relative to current contract terms to achieve savings for ratepayers while recognizing the socio-economic importance of these forest sector facilities. Separately, the government will work with the forest sector in transitioning to the use of forest sector waste for higher value renewable fuels, consistent with the CleanBC plan.

BC Hydro stopped taking any applications under the Standing Offer Program in August 2017. The Standing Offer Program will be suspended indefinitely by BC Hydro in accordance with a regulation being issued by the government under the *Clean Energy Act*. This suspension applies to new Electricity Purchase Agreements only, with the exception of five specific projects, each of which are part of Impact Benefit Agreements with BC Hydro and/or are mature projects that have significant Indigenous Nations involvement[2].

Capital Program, Operating Costs and Revenues

BC Hydro will reduce planned capital additions by $2.7 billion, from $18.5 billion to $15.8 billion over the 10 years from Fiscal 2020 to Fiscal 2029. BC Hydro has carefully considered system impacts. Safety and reliability risks will be managed through targeted investments, with no reductions in investments to meet legal, regulatory or tariff requirements.

Despite significant cost pressures, BC Hydro expects to limit base operating cost increases below the forecast rate of provincial inflation over the Fiscal 2020 to Fiscal 2024 period through savings from initiatives, prudent cost management and other measures such as leveraging Lean principles through BC Hydro's Work Smart process improvement program.

At the same time as it implements cost saving strategies, BC Hydro will also work to increase revenues, including attraction of additional domestic demand.

2 *https://www.bchydro.com/news/press_centre/news_releases/2018/bc-hydro-to-proceed-with-five-first-nations--clean-energy-projec.html*

1.3 NEXT STEPS

Regulatory changes have been or are being made to implement most Phase 1 outcomes. Where needed, legislation to implement Phase 1 outcomes is expected to be introduced in the Spring 2019 Legislative Session. See Appendix D for further detail.

Through a separate initiative, government will engage with Indigenous Nations to discuss the impacts the indefinite suspension may have on the economic individual nations, and how these impacts may be mitigated. Further information about this engagement process is available at ***www.engage.gov.bc.ca/SOPengagement.ca***.

BC Hydro will begin negotiations with those parties holding biomass Electricity Purchase Agreements expiring before March 31, 2022 for new load offset and/or energy purchase agreement(s). The government will also begin working with the forest industry on production of clean fuels to support the long-term sustainability of the sector and help meet the CleanBC greenhouse gas emission reduction targets.

The Phase 1 Review will inform BC Hydro's next Revenue Requirements Application, to be filed with the BCUC in February 2019.

2. Strategic Context

Electricity rates in B.C. have risen by over 70% in the past 10 years. Though the most recent Hydro Quebec Rate Comparison Report[3] shows that BC Hydro has the third lowest residential rates in North America, government's overarching policy commitments include making life affordable for British Columbians and building a strong, sustainable, innovative economy. In line with these objectives, the government's mandate letters to BC Hydro and the Minister of Energy, Mines and Petroleum Resources include commitments to conduct the Review.

In addition to the foregoing context on rates, over a number of years, BC Hydro has secured energy through power acquisitions from Independent Power Producers, the addition of Site C, and, to a lesser extent, through upgrades to its existing facilities. While electrification to support the CleanBC Plan will consume some of this surplus energy, growth in demand from existing electricity use is slowing, which means BC Hydro expects to remain in surplus into the 2030s.

BC Hydro operates in an evolving environment. For example, more stringent environmental and safety standards add valuable protections for the environment and enhance safety of workers and the public, while also adding cost and complexity to BC Hydro's work.

The first phase of the Review was designed to identify cost savings, efficiencies, new revenue streams and other changes to keep electricity rates affordable and predictable over the long-term, while ensuring BC Hydro has the resources it needs to continue providing clean, safe and reliable electricity.

Equally important, this phase also focused on helping to ensure sound financial and regulatory oversight of BC Hydro.

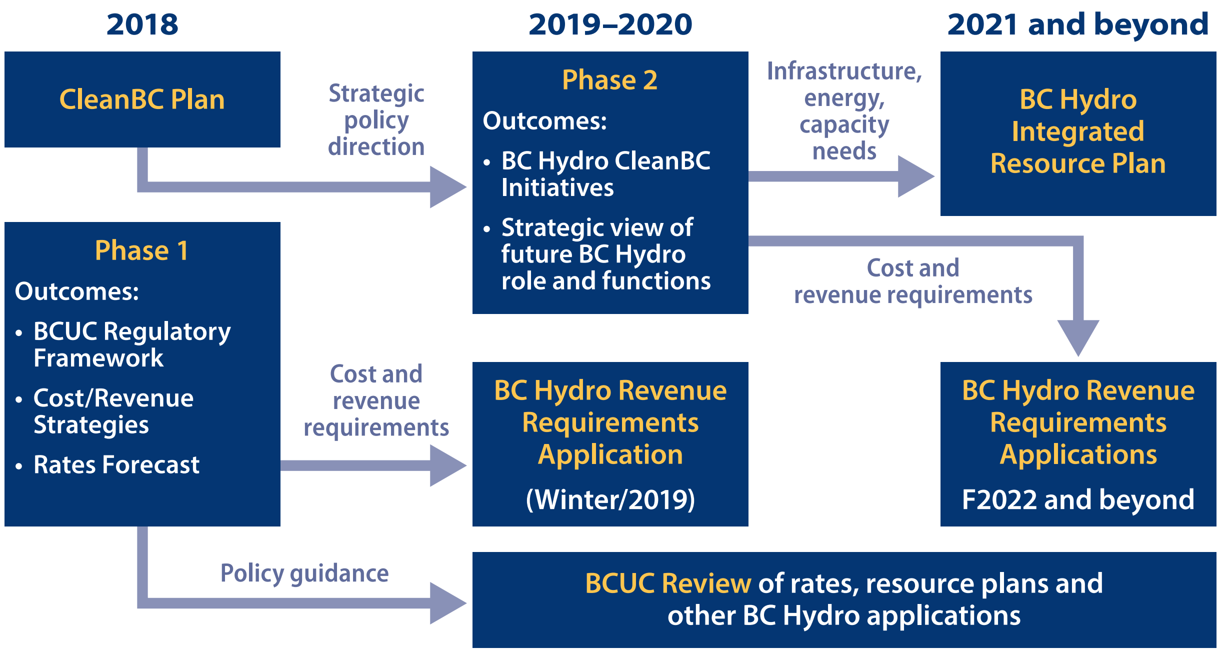
The outcomes from this first phase are assisting BC Hydro in preparing its next Revenue Requirements Application, to be filed with the BCUC in February 2019. During the BCUC's review of that application, stakeholders and the public will have a further opportunity to see and comment on how the outcomes of the first phase of the Review have influenced BC Hydro's financial/operational plan and electricity rates.

Phase 2 of the Review will focus on transformational aspects to changing energy markets. It will be informed by new government strategies, including the CleanBC plan. While Phase 1 focused on the next five years, Phase 2 will take a longer-term view and focus on recommendations to ensure BC Hydro is well positioned to maximize opportunities flowing from shifts taking place in the global and regional energy sectors, technological changes and climate objectives. Terms of Reference for Phase 2 of the Review will be finalized and made public in early 2019.

3 *http://www.hydroquebec.com/data/documents-donnees/pdf/comparison-electricity-prices.pdf*

The figure below shows the interrelated nature of these various policy activities:

Figure 1: Policy Activities



2.1 PREVIOUS REVIEWS OF BC HYDRO

In 2011, a provincial government Deputy Ministers' Committee conducted a review of BC Hydro, focusing on cost reductions, efficiency and several policy issues. As a result, BC Hydro reduced its operating costs by $390 million over a three-year period, reprioritized capital expenditures and reached cost-effective agreements with service providers. In addition, BC Hydro and the government worked together to review the growth of regulatory accounts, with a report completed in March 2014.

In addition to reductions stemming from previous reviews, in 2013 the government and BC Hydro again worked together to reduce pressure on rates and the result was the 2013 10 Year Rates Plan. Government and BC Hydro continued to work together and took further actions after the 10 Year Rates Plan was released to ensure that its targets would be met. The 10 Year Rates Plan covering Fiscal 2015 to Fiscal 2024 had three main components: BC Hydro actions to reduce costs; government actions; and the creation of a Rate Smoothing Regulatory Account. BC Hydro actions related to the 10 Year Rates Plan included finding operating savings to limit cost growth, reducing capital expenditures and selling surplus properties. Government actions included the elimination of the third tier of the provincial water rental rate, reducing and then freezing BC Hydro's allowed net income for rate-setting purposes, and reducing and ultimately eliminating dividend payments to the government. Government issued directions to the BCUC and made other regulations to implement the 10 Year Rates Plan.

The Rate Smoothing Regulatory Account, established in 2014 as a result of government direction, was used to smooth the higher annual rate increases that would have been required to cover BC Hydro's costs in the early years of the 10 Year Rates Plan by enabling BC Hydro to defer collection of revenues from ratepayers to the later years of the Plan.

As of March 31, 2018, the Rate Smoothing Regulatory Account had reached a balance of $815 million. BC Hydro was scheduled to further defer another $325 million in revenues into the Rate Smoothing Regulatory Account in Fiscal 2019 (April 1, 2018 to March 31, 2019), which would bring the total balance to approximately $1.14 billion by March 31, 2019. The balance in the account was to be recovered from ratepayers by the end of the plan in Fiscal 2024 (April 1, 2023 to March 31, 2024).

2.2 BCUC Oversight of BC Hydro

BC Hydro's primary role is to provide safe, reliable and affordable power to its customers. BC Hydro is regulated by the BCUC, which is an independent agency of the government that is responsible for regulating B.C.'s energy utilities. The BCUC works to ensure that British Columbians get value from their utilities with safe, reliable energy services, while also ensuring the owners of the entities it regulates are able to earn a fair return on their invested capital. BC Hydro submits applications to the BCUC every few years to obtain approval of its proposed rate increases. The BCUC then holds a regulatory process to determine if these rate increases are in the best interests of BC Hydro's ratepayers, while also ensuring the long-term sustainability of BC Hydro.

At the same time, as a Crown corporation and agent of government, BC Hydro is also an important instrument of public policy. As such, government may require BC Hydro to undertake projects that benefit the public good, such as projects that support the achievement of the government's legislated greenhouse gas emissions reduction targets or those that promote reconciliation with First Nations and Indigenous peoples of B.C. This dual role can, and has, created conflict between BCUC decisions and government's desire to advance policy priorities through its Crown corporation.

Under the *Utilities Commission Act*, the government has the authority to provide legal direction to the BCUC to guide or define the outcomes of the BCUC's decision-making. The previous government used this authority when implementing the 2007 Energy Plan and the 2013 10 Year Rates Plan. Of note, government directed the BCUC to set or cap BC Hydro's rate increases at specific levels in the first five years of the 10 Year Rates Plan. Government also directed the BCUC to:

- establish BC Hydro's Rate Smoothing Regulatory Account;
- set BC Hydro's allowed net income for rate-setting purposes, which forms part of the government's overall revenue projections within its annual Fiscal Plan;
- approve the scope and amortization periods of some of BC Hydro regulatory accounts; and,
- allow BC Hydro to implement a number of policy decisions, such as the Smart Metering Infrastructure Program and the decommissioning of the Burrard Thermal Generating Station.

The following table outlines the rate increases in the first five years of the 2013 10 Year Rates Plan:

Table 2: Rate Increases in the 2013 10 Year Rates Plan for Fiscal 2015 to Fiscal 2019

2013 10 Year Rates Plan	Fiscal 2015	Fiscal 2016	Fiscal 2017	Fiscal 2018	Fiscal 2019
Rate Increases	9% Rate increase set by Direction	6% Rate increase set by Direction	4.0% Rate cap set by Direction	3.5% Rate cap set by Direction	3.0% Rate cap set by Direction

In the final five years of the 10 Year Rates Plan, the rate increases were to be set by the BCUC, with a target of 2.6% annual rate increases in each of those years.

2.3 Concerns from the Auditor General

The Auditor General is an independent Officer of the Legislature, and, under a fixed term of office in legislation, has a mandate to conduct audits and performance reviews of government entities, including ministries, Crown corporations and other organizations controlled by, or accountable to, the provincial government. These audits and reviews are intended to report on how well government is managing its responsibilities and resources. The Office of the Auditor General will be taking over as BC Hydro's external auditor starting April 1, 2019.

Past and current Auditors General have expressed an opinion that the government has inappropriately fettered the BCUC's oversight of BC Hydro (including with respect to setting rates and directing other outcomes) and that BC Hydro may not be fully operating as a cost of service utility, where rates are set to ensure a utility is able to recover its costs and provide a reasonable return to its shareholder. Because of these concerns, the current Auditor General qualified the government's Fiscal 2017 and Fiscal 2018 Public Accounts.

In providing a qualified opinion on government's Fiscal 2018 Public Accounts, the Auditor General noted that the government, when consolidating BC Hydro, did not meet accepted accounting standards for rate-regulated accounting because government direction has largely pre-determined BC Hydro's allowable costs, net income, rate increases and regulatory accounts, leading to rate increases that have not been designed to fully recover the cost of service.

In response to the Auditor General's qualification of the government's Fiscal 2017 Public Accounts, government made a $950 million summary-level adjustment in its financial statements in August 2018. The Auditor General's opinion recognized government's negative adjustment of $950 million and noted that government's Crown corporation earnings and year-end surplus would have been $4.505 billion lower if government had made a full negative adjustment of $5.455 billion, representing the total balance of BC Hydro's regulatory accounts as of March 31, 2018. Though the Auditor General acknowledged the adjustment and its purpose, she noted that there was more work to be done to restore the BCUC's independent oversight of BC Hydro and to avoid future qualifications.

3. Approach, Scope & Governance of Phase 1

In the first phase of the Review, an Advisory Group consisting of staff from the Ministry of Energy, Mines and Petroleum Resources, the Ministry of Finance, and BC Hydro reviewed issues and opportunities that were raised by staff working groups. The Advisory Group was co-chaired by the Assistant Deputy Minister, Electricity and Alternative Energy Division of the Ministry of Energy, Mines and Petroleum Resources and the Chief Accounting Officer of BC Hydro.

The Review was conducted internally to leverage the knowledge of staff in both Ministries and at BC Hydro, especially regarding the regulatory system in B.C. and BC Hydro's business.

The Advisory Group reported monthly to the Steering Committee, which provided feedback and advice on recommendations to responsible Ministers. The Steering Committee was comprised of:

- Deputy Minister, Ministry of Energy, Mines and Petroleum Resources
- Deputy Minister, Ministry of Finance
- President and Chief Operating Officer, BC Hydro
- Executive Chair, BC Hydro
- Executive Vice-President, Finance, Technology, Supply Chain & Chief Financial Officer, BC Hydro[4]

The Terms of Reference for Phase 1 of the Review are included as Appendix A.

4 This member joined the Steering Committee in August 2018.

4. Phase 1 Outcomes

Decisions resulting from Phase 1 of the Review focus on ensuring sound financial and regulatory oversight of BC Hydro and measures to keep rates affordable.

4.1 Ensuring Sound Financial and Regulatory Oversight of BC Hydro

To help ensure sound financial and regulatory oversight of BC Hydro, the government has made changes to the accounting standards BC Hydro must follow and is taking steps to enhance the BCUC's oversight of BC Hydro. This is being done in a way that recognizes impacts to the government's overall Fiscal Plan, while advancing government's social, economic and environmental priorities. These changes also aim to address previous concerns that have been raised by the Auditor General and transition toward increased independent regulatory oversight.

4.1.1 Write-off of the Rate Smoothing Regulatory Account

The balance of the Rate Smoothing Regulatory Account on BC Hydro's financial statements as of March 31, 2018 was $815 million. Based on the previous government's 10 Year Rates Plan, BC Hydro was scheduled to further defer about $325 million in revenues into the Rate Smoothing Regulatory Account in Fiscal 2019, which would have brought the total Rate Smoothing Regulatory Account balance to approximately $1.14 billion. The balance in the account was to be recovered from ratepayers by the end of the plan in Fiscal 2024.

Rate smoothing can be an appropriate goal and an appropriate reason to have a regulatory account, but in this case, the BCUC was directed by government to allow the account without the ability to provide appropriate review and oversight.

As an outcome of the review, government has accepted the recommendation that BC Hydro cease using the Rate Smoothing Regulatory account and write off the entire balance in Fiscal 2019, which will significantly reduce BC Hydro's regulatory account balances. This means that the balance in the account will not be recovered from ratepayers. BC Hydro will request closure of the account in its Fiscal 2020 to Fiscal 2021 Revenue Requirements Application, for be filed with the BCUC in February 2019.

As the cost of the write-off will be borne by BC Hydro and the government, there will be an approximate $190 million negative net impact to the Province's Fiscal Plan in Fiscal 2019. This figure represents the amount over and above the $950 million summary-level adjustment the government made to its Fiscal 2018 financial statements. The impact on BC Hydro's financial statements is an expected net loss of approximately $425 million for Fiscal 2019. Ongoing debt servicing costs (estimated at $45 million annually) related to the Rate Smoothing Regulatory Account will continue to be recovered from ratepayers.

The table below summarizes these changes and other expected reductions in Fiscal 2019 that are further described in section 4.1.3 as a result of other forecast changes (e.g., positive trading results and the continued collection of most regulatory accounts in rates).

Table 3: Total BC Hydro Regulatory Account Balance

Total BC Hydro Regulatory Account Balance ($ billions)	Province of BC Public Accounts	BC Hydro Financial Statements
Ending Balance Fiscal 2018	$4.505[A]	$5.455[A]
Rate Smoothing Write-off	-0.186[A]	-1.136[A, B]
Other Forecast Changes in Fiscal 2019	-0.696	-0.696
Forecast Ending Balance Fiscal 2019	$3.623	$3.623

A *There are differences between the Public Accounts and BC Hydro's financial statements because the government already made a $950M summary-level adjustment to its financial statements at the end of Fiscal 2018 to reduce BC Hydro's net regulatory asset balance.*

B *BC Hydro has written off the balance of the Rate Smoothing Regulatory Account in its third quarter financial statements, for the period ending December 31, 2018. The balance at the time was $1.04 billion. The remaining amounts that would have been deferred to the account for the remainder of the fiscal year would have brought the total to $1.136 billion. These remaining amounts will impact BC Hydro's net income instead of being deferred and hence the total write-off impact is $1.136 billion in Fiscal 2019.*

4.1.2 Changes in Accounting Rules

The accounting rules that BC Hydro was required to follow under the *Budget Transparency and Accountability Act* included an exemption from the requirement that rates be set by an independent, third party regulator. The Auditor General has been critical of this exemption, which is unique to BC Hydro, and believes it means the rules BC Hydro was required to follow were not aligned with Generally Accepted Accounting Principles.

As an outcome of the Review, government has removed this exemption and the effect is that BC Hydro will adopt International Financial Reporting Standards (IFRS), without exception, as recommended by the Auditor General. This change is effective for BC Hydro's year-end financial statements for Fiscal 2019. IFRS rules permit the use of rate-regulated accounting, which is the practice of using regulatory accounts.

4.1.3 Enhanced BCUC Oversight of BC Hydro

The government is restoring the BCUC's authority to oversee key aspects of BC Hydro's business, including rate-setting and regulatory accounts, on a go-forward basis as discussed in the sections below.

The government has repealed Direction No. 7 under the *Utilities Commission Act*, which:

- implemented the previous government's 2013 10 Year Rates Plan by establishing set rate increases, rate caps or targets;
- required the BCUC to set the Deferral Account Rate Rider at 5% indefinitely;
- set BC Hydro's allowed annual net income for rate-setting purposes; and
- required the BCUC to approve creation of the Rate Smoothing Regulatory Account and the deferral of specified revenues into it.

Regulatory changes have been or are being made to implement most decision outcomes of Phase 1 of the Review. Legislation required to further implement Phase 1 decision outcomes is expected to be introduced in the Spring 2019 Legislative Session.

Regulatory Accounts

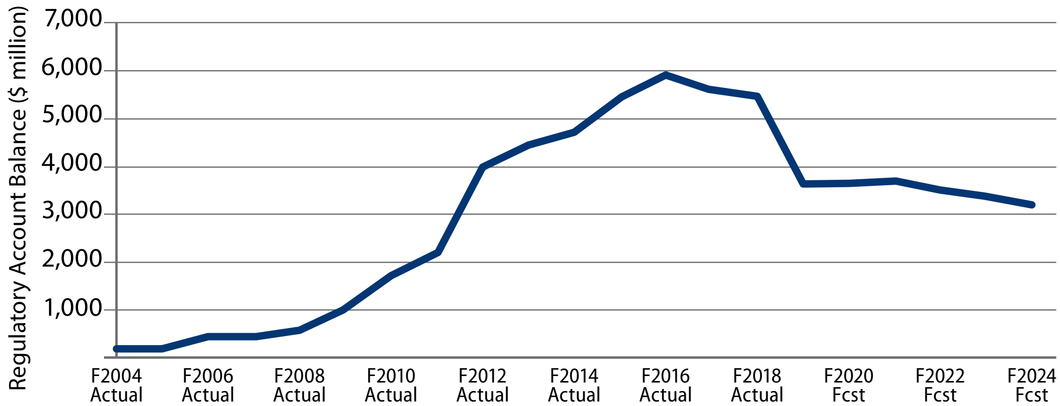
Regulatory accounts are commonly used by electric utilities in North America, are allowed under IFRS accounting rules and can be a useful tool with appropriate regulatory oversight. BC Hydro currently has 29 regulatory accounts, including the Rate Smoothing Regulatory Account. Over the last two years, BC Hydro's regulatory account balances have decreased, and BC Hydro is forecasting another decrease in Fiscal 2019 as a result of positive trading results and the continued collection of most accounts in rates.

Considering the write-off of the Rate Smoothing Regulatory Account, BC Hydro expects that the total regulatory account balance at the end of Fiscal 2019 will be $3.6 billion (as shown in Table 3), which is approximately 40% lower than the peak of nearly $6 billion at the end of Fiscal 2016 . In addition to the write-off of the Rate Smoothing Regulatory Account, BC Hydro forecasts a decrease in other accounts of approximately $700 million in Fiscal 2019 alone, due to positive operating results, positive results for Powerex (its marketing subsidiary) and a change related to accounting standards.

After the write-off of the Rate Smoothing Regulatory Account, BC Hydro has regulatory mechanisms in place to recover the balances of 25 of its 28 regulatory accounts over various periods of time, which represents approximately 86% of the net regulatory account balance forecast ending Fiscal 2019 net regulatory account balance.

Figure 2 shows BC Hydro's actual and forecast total year-end regulatory account balances from Fiscal 2004 through Fiscal 2024. This includes the impact of writing off the balance in the Rate Smoothing Regulatory Account in Fiscal 2019.

Figure 2: BC Hydro's Total Regulatory Account Balances (Actual and Forecast) for Fiscal 2004 to Fiscal 2024



Note: Fiscal 2019 – Fiscal 2024 forecast per Fiscal 2019 Quarter 3 Forecast

Figure 2 shows that BC Hydro's forecast total regulatory account balance of $3.2 billion at the end of Fiscal 2024 is over 45% lower than the peak in Fiscal 2016. Approximately 98% of the forecast balance at the end of Fiscal 2024 is related to balances in accounts that are long-term in nature (for example, accounts that provide longer-term benefits to customers such as the Demand-Side Management and Site C Regulatory Accounts) and that are thus collected from ratepayers over longer periods.

Previous government directions directed the establishment of some of the accounts, directed the deferral of certain costs into those accounts and directed the amortization period (recovery from ratepayers) of some of the accounts.

As a result of Phase 1 of the Review, the BCUC will be able to review the scope and amortization periods for all of BC Hydro's regulatory accounts on a go-forward basis. Select accounts will continue to be subject to government direction, as they directly relate to specific past and currently-confirmed government policy decisions. These accounts include the Mining Customer Payment Plan Regulatory Account and certain costs related to the Demand-Side Management Regulatory Account.

As a result of the Review, government is also directing the BCUC to allow BC Hydro to recover the March 31, 2019 balances of all of its regulatory accounts in rates over time, with the exception of the Rate Smoothing Regulatory Account. The write-off of this account will further reduce BC Hydro's total overall forecast regulatory account balance as shown in Figure 2. This helps ensure that BC Hydro is able to recover the costs it has incurred as a result of past policy decisions. The government has made the regulatory changes necessary to implement these Review outcomes.

Deferral Account Rate Rider (DARR)

The Deferral Account Rate Rider (DARR) is a surcharge (currently 5%) that applies to all charges on customer bills, excluding taxes and levies. Funds collected under the DARR were intended to be used to pay down BC Hydro's three energy deferral account balances (the

Heritage Deferral Account; the Non-Heritage Deferral Account; and the Trade Income Deferral Account). These energy deferral accounts capture variances between forecast conditions when rates are set (such as reservoir inflows, market prices and customer demand) and what actually occurs in a given year.

As part of the 2013 10 Year Rates Plan, government required the BCUC to set the DARR at 5% indefinitely, regardless of the balances in the applicable regulatory accounts. BC Hydro has used some of the over $200 million per year in revenue from the DARR to offset other costs. It was expected that the DARR would remain at 5% at least through the end of the 2013 10 Year Rates Plan in Fiscal 2024.

Following the Review, the government has repealed Direction No. 7 to the BCUC. Going forward, the BCUC will have the ability to determine how the DARR is set and applied. In its upcoming Revenue Requirements Application, BC Hydro will be proposing to lower the DARR from 5% to 0%, based on forecast March 31, 2019 balances in BC Hydro's three energy deferral account balances. This reduction in the DARR is reflected in the table of bill impacts shown on page 34.

Integrated Resource Plan (IRP)

The Integrated Resource Plan (IRP) contains BC Hydro's 20-year projection of electricity demand in B.C. and its comprehensive plan to meet this demand, including through existing facilities, demand-side management (conservation and efficiency efforts), construction or extension of new facilities and new or renewed Electricity Purchase Agreements with independent power producers.

The *Clean Energy Act* required BC Hydro to submit its IRP to government for approval by November 2018. The legislation has significantly limited the BCUC's oversight of BC Hydro's long-term plan, which hampers the BCUC's decision making on various BC Hydro activities, including its applications on capital projects.

The government has amended the deadline for the submission of the next Integrated Resource Plan to February 2021 to allow time for the IRP to be informed by the second phase of the Review and the actions required to support the CleanBC plan.

The government intends to introduce legislation in Spring 2019 to restore the BCUC's oversight authority to review and approve BC Hydro's IRP. Government's policy objectives will continue to inform BC Hydro's development of the IRP under this process moving forward.

Dividends and Net Income

BC Hydro's dividend payments provide cash flow to the government and allow the government to reduce its borrowing requirements. Dividend payments do not directly impact the surplus/deficit in government's Fiscal Plan. In accordance with government regulations, BC Hydro's dividends payable to government are reduced by $100 million per year as compared to the dividend paid in the preceding year. This will continue until the dividend payable reaches zero in Fiscal 2020, at which point dividends would not be payable again until BC Hydro reaches a debt to equity ratio of 60:40 under current policy.

A debt to equity ratio of 60:40 is comparable to other utilities in Canada. The regulation regarding dividends was put in place to support BC Hydro in paying down its debt, to improve its debt to equity ratio and to help BC Hydro finance its upcoming capital investment needs. As a result, BC Hydro's Fiscal 2019 dividend will be $59 million and $0 for the foreseeable future thereafter.

Net income is the return that BC Hydro is allowed to earn in a given fiscal year. BC Hydro's net income forms part of the government's revenue for government budget purposes. Net income is also a key source of cash resources for BC Hydro that helps finance capital and reduce borrowing.

Direction No. 7 to the BCUC set BC Hydro's allowed net income for rate setting purposes at a fixed amount of $712 million for Fiscal 2019 and all subsequent fiscal years. Setting allowed net income in regulation provides certainty for BC Hydro and government in developing the overall Provincial Budget and Fiscal Plan. However, this means that allowed net income is established by government rather than by the BCUC and may not reflect an appropriate return for BC Hydro's shareholder. This practice has been criticized by the Auditor General.

As an outcome of Phase 1 of the Review, the government will re-empower the BCUC to set BC Hydro's allowed net income, following a two-year transition period for Fiscal 2020 and Fiscal 2021 where BC Hydro's allowed net income of $712 million will remain in place. This transition period will allow time for the BCUC to review BC Hydro's next Revenue Requirements Application and to undertake a separate process to determine an appropriate rate of return prior to resuming the regulation of BC Hydro's allowed net income in Fiscal 2022. Government may provide policy guidance to the BCUC and/or participate in regulatory proceedings to inform this process.

Address Government Priorities

The BCUC undertakes its role so that it applies sound utility regulatory principles to its decisions, with a focus on the impact on BC Hydro's ratepayers. That means that the BCUC is not required to implement policy that does not stand on its own from a regulatory perspective. Finding #1 of the 2015 independent review of the BCUC, conducted by an expert Task Force in consultation with the BCUC and stakeholders, indicated that:

> It is the provincial government's prerogative to set provincial energy policy, to define the Commission's mandate, and to direct the Commission on specific matters…
> In the future, government should delineate policies to the Commission clearly, and in advance of Commission processes, then leave the Commission to act independently within its mandate. Where the government does wish to retain the final decision in a matter to itself, and there are complex issues within the expertise of the Commission that should be reviewed, the government should consider referring the matter to the Commission for a recommendation only.

As result of Phase 1 of the Review, if there is a priority policy item for the government to advance, government will introduce legislation or provide direction that supports it. With this approach, the BCUC will be empowered to make decisions with respect to BC Hydro in a mostly unencumbered way, in alignment with the laws and regulatory principles that are applicable to it. Where required, government may also provide policy guidance by participating in proceedings (through a letter of comment or as an intervener) or by issuing directions to the BCUC to help ensure that government's priorities are appropriately considered as part of the BCUC's decision-making processes.

There are also certain directions to the BCUC that will continue to ensure that rates remain affordable and to support the continued implementation of government policy objectives. Government will continue to direct the BCUC:

- not to calculate "expenditures for export", nor include these costs from recovery in BC Hydro's rates;
- to retain a prohibition on "retail access," unless requested by a utility;
- not to rebalance BC Hydro's rates, unless requested by a utility; and
- not to regulate Powerex.

Expenditures for Export

Among other things, the *Clean Energy Act* was intended to position B.C. to pursue opportunities for electricity export, given the anticipated high market electricity prices for clean electricity at the time. The *Clean Energy Act* set out the concept of "expenditures for export," which is unique to BC and not applicable in other Canadian jurisdictions.

To ensure the costs of pursuing such opportunities were not passed along to ratepayers, the BCUC was obliged to ensure that BC Hydro's rates would not allow BC Hydro to recover "expenditures for export" from ratepayers. Under Direction No. 7, government directed the BCUC to refrain from considering these expenditures.

In recent years, shale gas development and subsidization of renewable energy development in the United States have led to low market prices for electricity. As a result, the pursuit of large scale electricity export opportunities has lost its economic rationale and, therefore, the expenditure for export provisions are no longer required.

Government has repealed Direction No. 7 and intends to introduce legislation in Spring 2019 to amend the *Clean Energy Act* to repeal the concept of expenditures for export. In the interim, the government will continue to direct the BCUC to refrain from considering expenditures for export when determining BC Hydro's rates.

Retail Access

Retail access is the ability for customers to secure electricity from the market via a third-party provider rather than the local utility such as BC Hydro. Interest in retail access fluctuates with electricity market prices, with customers interested when open market prices are lower than local supply and not interested when market prices are higher than local supply. In a surplus situation, allowing retail access increases the amount of surplus energy that BC Hydro must export, possibly at a loss, increasing costs borne by ratepayers who do not or cannot opt for retail access.

To minimize potential costs to ratepayers, retail access for BC Hydro customers is currently prohibited, and, as a result of the Review, this prohibition will continue. The government has extended the prohibition of retail access through regulation. The prohibition will continue until or unless a public utility, in this case BC Hydro, requests otherwise.

Prohibiting retail access is not unique to BC Hydro. The prohibition of retail access can protect electricity consumers by providing price stability and reducing the duplication of costs that must be passed on consumers (for example, duplicative systems of billing, customer service etc.). In Canada, it is generally true that regions with low and stable electricity prices like Quebec, Manitoba and British Columbia do not have full retail access. In Canada, only Ontario and Alberta have full retail access for electricity rates. In these two provinces, customers can choose to have access to wholesale market prices for energy. The remaining provinces have vertically integrated utilities where customers pay regulated electricity prices.

There is evidence from the U.S. that the average retail price of electricity tends to be more volatile in regions with full retail markets.[5]

Rate Rebalancing

In addition to setting overall rates for public utilities, the BCUC may also determine how these overall costs are to be allocated between the utility's various customer classes (i.e. residential, commercial, industrial). In doing so, the BCUC strives to align, as closely as possible, the revenues received from each class with the cost the utility incurs to serve each class. If the current revenue-to-cost ratios for one or more customer classes fall above or below this range (generally +/- 5% from 100% cost recovery), the BCUC may decide to rebalance rates by increasing or decreasing rates for each customer class by a different amount until an appropriate balance is achieved.

Currently, BC Hydro's residential customers are covering 90.8% of the cost of serving them. Commercial customers are paying as much as 123.5% of their cost of service and industrial customers are just over or under 100%.[6] If the BCUC were to rebalance rates to address this imbalance, annual rate increases for residential customers for Fiscal 2020 could be up to 2.2% higher[7] than currently forecast rate increases. At the same time, rates for commercial customers would decrease and industrial rates would remain approximately the same.

The BCUC has been prohibited from rate rebalancing for the purpose of changing the revenue-to-cost ratios between BC Hydro's customer classes for each of Fiscal 2017, Fiscal 2018 and Fiscal 2019. As a result of the Review, to minimize rate increases for BC Hydro's approximately 1.8 million residential accounts, the government will continue to prohibit the BCUC from rebalancing BC Hydro's rates for Fiscal 2020 and Fiscal 2021 through regulation, since a near-

5 *https://www.nrel.gov/docs/fy18osti/68993.pdf*

6 As reported in BC Hydro's fully allocated cost of service (FACOS) report, filed with the BCUC in March 2018.

7 Equivalent to a 2% increase in the cost of service ratio for BC Hydro's residential customers for Fiscal 2020.

term rebalancing of BC Hydro's rates could conflict with government's commitment to keep life affordable for British Columbians. The decision to prohibit rate rebalancing is a matter of public policy.

The government intends to introduce legislation in Spring 2019 to amend the *Utilities Commission Act* to permanently prevent the BCUC from rebalancing rates unless otherwise requested to do so by a public utility.

Rate rebalancing is also prohibited through legislation in Quebec.[8]

Powerex Corp.

Powerex Corp. is a BC Hydro subsidiary and a key participant in energy markets across North America, buying and selling wholesale power, renewable and low-carbon energy and products, natural gas, ancillary services and financial energy products. Powerex's trade activities earn income which is beneficial to its shareholder (BC Hydro) and therefore to BC Hydro's ratepayers.

Powerex operates in competitive wholesale energy markets outside of B.C., where it is subject to regulation by the Federal Energy Regulatory Commission and other regulatory bodies for its wholesale activities. Falling under BCUC oversight would hamper Powerex's ability to compete and earn income in fast-moving and rapidly evolving competitive markets. For this reason, government will continue to restrict the BCUC from regulating the activities of Powerex as an outcome of the Review. It is worth noting that ICBC's optional insurance products, which also operate in a competitive environment, are not regulated by the BCUC.

4.2 Keeping Electricity Rates Affordable

For each fiscal year, BC Hydro forecasts the revenue that it needs to collect from its customers in order to cover its costs. This is known as its "revenue requirements."

BC Hydro has aging assets and an increasingly complex operating environment. It has limited ability to reduce its revenue requirements, because many of its costs are the result of past decisions, projects or contracts and are fixed. Approximately one-third of BC Hydro's Fiscal 2019 revenue requirements[9] are finance charges related to debt already incurred by BC Hydro, or capital amortization amounts resulting from previously incurred capital expenditures, while water rentals and cost of energy, including energy procurement from Independent Power Producers, make up just over one-third.

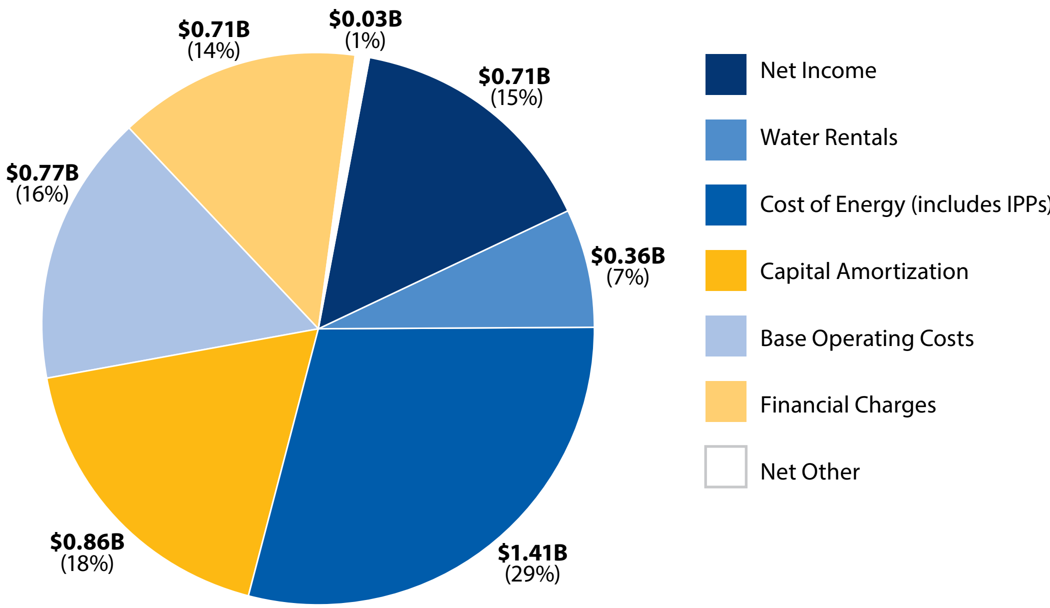
Even though BC Hydro's finance charges relate to debt that has already been incurred, BC Hydro has taken steps to minimize these costs. Through its debt management strategy, BC Hydro has used hedging to lock in low interest rates to the benefit of ratepayers and will continue to do so. This strategy, coupled with BC Hydro's strong credit rating (backed by the Province), will continue to benefit ratepayers.

8 *http://legisquebec.gouv.qc.ca/en/ShowDoc/cs/R-6.01*

9 Before transfers to the Rate Smoothing Regulatory Account

Figure 3 below shows BC Hydro's forecast revenue requirements for Fiscal 2019.

Figure 3: BC Hydro's Total Revenue Requirement for Fiscal 2019



Despite the example of debt outlined above, because many costs are already incurred or committed, the first phase of the Review focused on BC Hydro's controllable costs drivers, revenue opportunities, and activities to keep rates affordable and support BC Hydro's continued financial sustainability. The Review identified the following strategies to enhance BC Hydro's long-term financial position:

- Write-off of the Rate Smoothing Regulatory Account
- Reduce future energy costs of purchases from Independent Power Producers
- Reduce planned capital expenditures and additions
- Tightly manage controllable operating costs
- Increase revenues

4.2.1 Write-off of the Rate Smoothing Regulatory Account

As discussed above, government has accepted the recommendation under the review that BC Hydro cease using the Rate Smoothing Regulatory Account and write off the entire balance in the account in Fiscal 2019. This means that the balance in the account will not be recovered from ratepayers. This write-off will reduce BC Hydro's total overall forecast regulatory account balance as at March 31, 2019 by roughly 24%, from $4.7 billion to $3.6 billion.

Lowering BC Hydro's overall regulatory account balance also means lowering the amount that would be otherwise recovered from ratepayers, thus reducing rate pressures over the next five years. BC Hydro continues to collect almost all of its remaining regulatory account balances in rates already and will continue to do so over recovery periods determined by the BCUC.

Through government direction, the ongoing debt servicing costs related to the Rate Smoothing Regulatory Account (estimated at $45 million annually) will continue to be recovered from ratepayers.

BC Hydro's debt has been rising as a result of its significant Capital Plan expenditures (further discussed in Section 4.2.3). In addition to affecting ongoing debt servicing costs, the write-off of the Rate Smoothing Regulatory Account reduces BC Hydro's accumulated equity balance. The impact on BC Hydro's debt:equity ratio, a key ratio in assessing BC Hydro's financial position, will exceed 80:20 at the end of Fiscal 2019. A debt:equity ratio at or below 80:20 is desirable and, with no dividends expected to be payable for the foreseeable future, BC Hydro forecasts that its debt:equity ratio will return to 80:20 by the end of Fiscal 2020), and that the ratio will continue to decline in the years that follow. BC Hydro forecasts a ratio of 76:24 at the end of Fiscal 2024.

4.2.2 Reduce Future Energy Costs from Independent Power Producers

BC Hydro has been purchasing electricity from Independent Power Producers since the 1980s. The 2002 Energy Plan relied on the private sector for new power generation and prohibited BC Hydro from developing new generation resources other than Site C and additions to certain heritage hydroelectric facilities. As a result, BC Hydro began procuring significant amounts of energy from Independent Power Producers under long-term Electricity Purchase Agreements, typically with contract terms of 20-40 years. BC Hydro currently holds over 130 contracts with Independent Power Producers, which represent over $51 billion in future financial commitments as of April 2018. Additional context can be found in the separate review by independent consultant Ken Davidson.

The cost of energy procured from Independent Power Producers is now one of BC Hydro's biggest cost drivers and these costs will be recovered from ratepayers. Though BC Hydro has not conducted competitive calls for power since 2011, it is projected to have an energy surplus into the 2030s.

The CleanBC plan was released by government in December 2018. It outlines government's plan to reach 75% of its 2030 climate targets through the reduction of greenhouse gas emissions in transportation, buildings and industry. By 2030, CleanBC could require incremental energy of approximately 4,000 gigawatt-hours over and above currently projected demand growth to electrify key segments of the economy. This is equivalent to increasing BC Hydro's system-wide capacity by about 8%. While it is expected that this increase in electricity demand can be mostly met with existing and planned resources, BC Hydro may require additional volumes of new clean electricity to B.C. after 2030 to achieve the remaining 25% of emissions reductions needed to meet government's climate targets for 2030 and beyond. As a result, achieving the government's climate targets could ultimately require additional capital projects.

In 2019, the second phase of the Review is expected to look at changing energy markets, new utility models, emerging technologies and strategies to deliver on CleanBC's longer-term electrification goals.

Although BC Hydro has implemented strategies to contain cost increases where possible, total annual energy acquisition costs are forecast to increase from $1.4 billion in Fiscal 2018 to $1.7 billion by Fiscal 2024. Over the remaining life of the portfolio of existing Electricity Purchase Agreements, $51 billion has been committed, which will be recovered from BC Hydro's ratepayers as energy is received over time.

The cost of energy purchased by BC Hydro from Independent Power Producers has increased dramatically over time. Projected increases in costs between Fiscal 2018 and Fiscal 2024 relate to a number of factors, such as:

- A growing number of projects with existing Electricity Purchase Agreements that have recently come into service (as of October 2018, there were 124 projects in operations) and the nine additional projects with agreements that are currently in development and not yet in service.
- Price escalation, as provided for under existing Electricity Purchase Agreements.
- New Electricity Purchase Agreements entered into under the Standing Offer Program or through negotiations related to contractual commitments to First Nations.

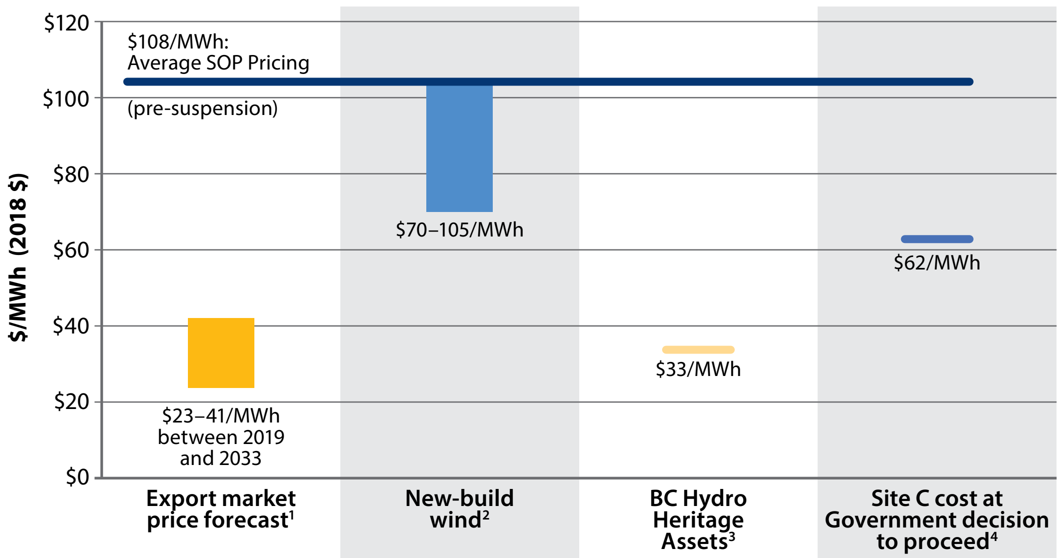
BC Hydro is continuing to manage its portfolio of Electricity Purchase Agreements to ensure that purchases of energy are administered within the terms of the agreements. BC Hydro will continue to exercise its contractual rights to control the costs of energy. However, there is limited flexibility to make significant reductions in energy procurement costs due to the structure of the existing Electricity Purchase Agreements. Existing Electricity Purchase Agreements with Independent Power Producers will not be cancelled as a direct result of Phase 1 of the Review. The primary opportunities for managing costs moving forward relate to expiring biomass agreements and the Standing Offer Program.

The first phase of the Review assessed the current cost to ratepayers of energy procurement and how those costs could be reduced in the future, particularly in view of electricity demand being lower than previously projected. Since the ability to manage cost of energy is largely limited to potential biomass Electricity Purchase Agreement renewals and the Standing Offer Program, actions flowing from the Review focused on these programs.

Figure 4 below shows that current prices for energy from the Standing Offer Program are significantly higher than the cost of generation from Site C and BC Hydro's heritage assets, as well as projected domestic and export market price forecasts.

- Standing Offer Program prices currently average $108 per MWh, which is over three times the cost of energy from BC Hydro heritage assets and nearly 75% higher than that of Site C; and
- Standing Offer Program prices are up to nearly five times higher than export market price forecasts.

Figure 4: Comparison of the Standing Offer Program pricing of an average of $108/MWh to Benchmark Energy Values



1 Source: as of Fall 2017

2 Source: Waneta Expansion regulatory filings (mid 2018)

3 Source: Fiscal Year 2018 Reporting

4 Source: as of December 2017

Please note that the characteristics of the energy products compared vary by product, and as such, Figure 4 is provided for illustrative purposes only in order to show the difference in prices. The illustrative prices also change over time due to market conditions and other factors. For example, prices for new-build wind have been changing and depend upon location, terrain and the prices of turbines and other technologies. Phase 2 of the Review will look at recent developments, trends and possible future scenarios in North American energy markets.

Background on Biomass Electricity Purchase Agreements

BC Hydro has contracted with biomass energy generators, mostly in the pulp and paper sector, since the 1980s. By the late-2000s, the number of biomass Electricity Purchase Agreements grew substantially through a number of procurement processes flowing from the 2007 Energy Plan and 2008 Bioenergy Strategy. Seven of these biomass Electricity Purchase Agreements are due to expire by the end of Fiscal 2022.

To generate electricity for delivery to BC Hydro, these Independent Power Producers burn wood waste generated by the forest sector, primarily from sawmills. This provides benefits to both the biomass generating facilities and the sawmills, as there are limited economically viable alternative uses for this wood waste at this time. In the absence of Electricity Purchase Agreements, some of these biomass generating facilities might no longer operate, which means that the wood waste may then need to be placed in landfills or burned in slash piles, leading to higher emissions of methane and/or particulates.

The pulp and paper sector in British Columbia operates in competitive, evolving global markets, with reduced domestic fibre supply and aging capital infrastructure. Biomass Electricity Purchase Agreements have been an important source of ancillary revenue for some of these companies. Eliminating or significantly scaling back biomass energy volumes and prices could have implications for jobs and the economy in forest-dependent communities, in addition to the environmental implications outlined above.

Five of the seven holders of expiring biomass Electricity Purchase Agreements are also BC Hydro customers. These Electricity Purchase Agreements are not only tied to the viability of the companies, but also to revenues to BC Hydro. The production of biomass energy associated with these Electricity Purchase Agreements advances certain environmental and socio-economic priorities of the government in relation to the forest sector, including maintaining regional fibre balance among various forest sector users and avoiding burning or landfilling of waste biomass.

Approach to Biomass Energy

BC Hydro, in consultation with government, has been working on an approach to biomass energy to determine the best course of action to deal with those biomass generating facilities with Electricity Purchase Agreements due to expire within the next three years. This approach considers fuel supply availability, cost effectiveness, impacts on BC Hydro ratepayers and other government priorities. The end result will be the imminent launch of the Biomass Energy Program.

In addition, the government will work with industry to develop a strategy to accelerate the development and implementation of renewable natural gas and bio-crude production within the forest sector to enhance its longer-term competitiveness and to support the CleanBC plan.

Biomass Energy Program

BC Hydro's Biomass Energy Program is a cost and volume limited, transitional measure intended to allow time for the forest sector to develop and implement new product lines consistent with the sector's industry diversification and competitiveness goals. It also allows for the continued operation of those biomass generating facilities with expiring Electricity Purchase Agreements over the next three years, providing potential optionality for BC Hydro should it require additional supply resources in the future.

Under the Biomass Energy Program, BC Hydro will continue to acquire biomass energy from facilities that have existing Electricity Purchase Agreements due to expire prior to March 31, 2022. BC Hydro will acquire up to 80% of the aggregate volume that these biomass generators have historically delivered to BC Hydro. BC Hydro will procure this energy through a combination of load offset and/or energy purchases. Load offset will be given priority over energy purchases.

Load offset is energy generated by a BC Hydro customer at its customer site to offset the energy the customer currently purchases from BC Hydro to serve its own needs. Eligible facilities will be offered an opportunity to offset load and/or negotiate energy purchase contracts depending on the volume of generation at their site.

BC Hydro could also purchase energy from companies that both BC Hydro customers and non-BC Hydro customers. These energy purchases offer additional revenue opportunities to those biomass energy generators who produce electricity that is surplus to their own needs at their customer site, and to those biomass energy generators that are not eligible for load offset because they are not BC Hydro customers.

To manage impacts on BC Hydro ratepayers, the prices and volumes of the biomass energy to be acquired by BC Hydro as part of this program will be lower relative to current contracts. The costs for this program must be managed within BC Hydro's rates forecast, and caps have been established for pricing, volume and overall costs of the program.

The government intends to provide a direction to the BCUC with respect to the approval of the program documentation and require the costs associated with the Biomass Energy Program to be recovered from ratepayers.

Renewable Fuels Acceleration Strategy

As a separate initiative, the government will work with industry to transition over time to other uses of waste residuals, including the production of higher value renewable energy products like Renewable Natural Gas (RNG) and bio-crude, which are considered to be carbon neutral as they capture methane that would otherwise escape into the atmosphere through the breakdown of organic matter.

The government has set targets to promote higher production levels of these low carbon fuel products under the CleanBC plan, one of a number of initiatives that will substantially reduce greenhouse gas emissions in the transportation, buildings and industrial sectors. Under the CleanBC plan, government has set targets for 15% of British Columbia's domestic natural gas supply to come from RNG and hydrogen, and 650 million litres of bio-crude to be produced from B.C. feedstocks by 2030. The Ministries of Energy, Mines and Petroleum Resources and Forests, Lands, Natural Resource Operations and Rural Development will work with industry to develop a renewable fuels acceleration strategy to assist in this transition.

While a shift to focusing waste fibre to produce biofuels instead of electricity has potential, focused work is required to move from a concept to commercial implementation, and this shift could take a number of years. The government considers the Biomass Energy Program to be a temporary measure, to provide time for the industry to transition to alternate forms of energy that align with longer-term provincial climate objectives.

Background on the Standing Offer Program

The Standing Offer Program is a continuous-intake program for small, permit-ready projects with a capacity of no more than 15 MW. The Standing Offer Program was developed in response to the 2002 Energy Plan. Initially launched in April 2008, it has become a vehicle for small Independent Power Producers, communities, First Nations and others who may lack the capacity to participate in larger, competitive procurement processes. As BC Hydro has not conducted competitive calls for power since 2011, the Standing Offer Program has become the primary energy procurement offering available to any organization seeking to secure a long-term Electricity Purchase Agreement with BC Hydro.

The Standing Offer Program is structured to focus on small projects. BC Hydro offered a set energy price derived from the results of prior market-based BC Hydro calls for power and this set price escalates each year with inflation. Although the Standing Offer Program price has been escalating with inflation since 2011, the cost of renewable generation technologies, especially wind, has been decreasing.

Starting in 2016, BC Hydro, the Ministry of Energy, Mines and Petroleum Resources and Clean Energy BC (Independent Power Producers' industry association) collaboratively examined options for the future of the Standing Offer Program. This review was ultimately halted, in light of concerns about BC Hydro's energy surplus and the government's commitment to carry out the Review.

Under the Standing Offer Program, BC Hydro had been acquiring up to 150 GWh of new supply each year. In August 2017, BC Hydro stopped accepting new project applications as the volume for 2017, 2018 and 2019 was fully subscribed. In March 2018, BC Hydro announced that it would not issue any new Electricity Purchase Agreements pending the completion of the Review, with the exception of five specific projects that are part of Impact Benefit Agreements for First Nations with BC Hydro and/or mature projects that have significant First Nations involvement.

Indefinite Suspension of the Standing Offer Program

Currently, the *Clean Energy Act* requires BC Hydro to maintain the Standing Offer Program and provides the government with the authority to prescribe circumstances that would allow BC Hydro to no longer be required to maintain the program. As a result of the Review, the Standing Offer Program will be suspended indefinitely, based on the current Standing Offer Program contract commitments. No new Electricity Purchase Agreements, other than the five specific projects noted above, will be issued by BC Hydro. This will significantly reduce BC Hydro's future costs for energy, which benefits ratepayers.

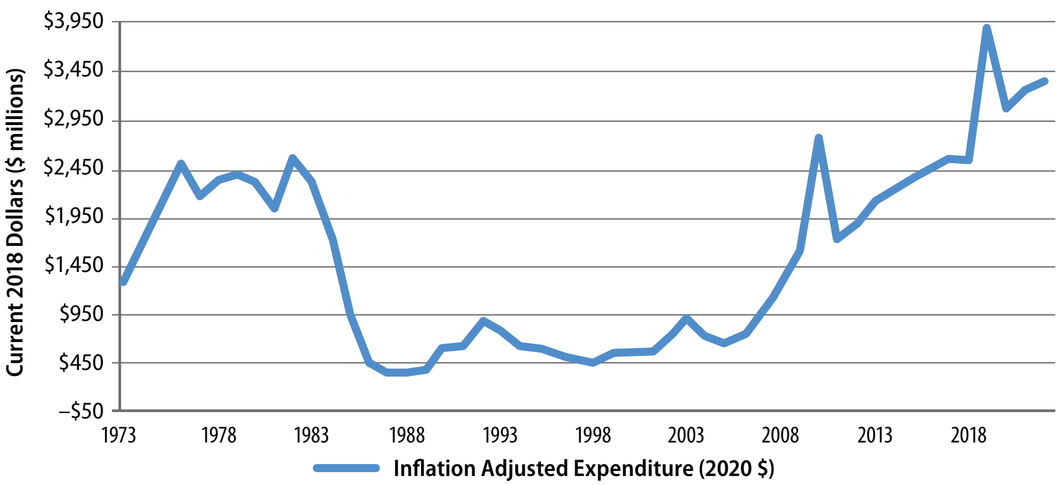
The government has issued a regulation under the *Clean Energy Act* that specifies that when the cumulative capacity of facilities with Standing Offer Program contracts exceeds 100 MW, BC Hydro is no longer obligated to maintain the Standing Offer Program. To date, BC Hydro has contracted with facilities with over 170 MW of capacity under the Standing Offer Program and so has exceeded that threshold. This means that existing Electricity Purchase Agreements remain valid, but BC Hydro will no longer be obligated to continue to maintain a Standing Offer Program, including offering any new Electricity Purchase Agreements.

Many Indigenous Nations have expressed interest in clean energy projects, which can bring economic benefits to their communities, stable sources of independent, long-term revenues to their governments and, for non-integrated areas, opportunities to displace diesel generation with clean electricity. The Ministry of Energy, Mines and Petroleum Resources will be engaging with Indigenous Nations to discuss the extent to which the indefinite suspension of the Standing Offer Program may affect the economic interests of individual Indigenous Nations. Further information about this engagement process is available at ***www.engage.gov.bc.ca/SOPengagement***

4.2.3 Reduce Planned Capital Expenditures and Additions

There are hundreds of BC Hydro capital projects currently underway that, together, make up one of the largest investments in electrical infrastructure in B.C.'s history. These investments maintain BC Hydro's system, much of which was built in the 1960s, 1970s and 1980s and is in need of upgrade and replacement to ensure ongoing safety and reliability for customers. BC Hydro's capital expenditures, starting in 1973 are shown in Figure 5 below.

Figure 5: BC Hydro Capital Expenditures through the years



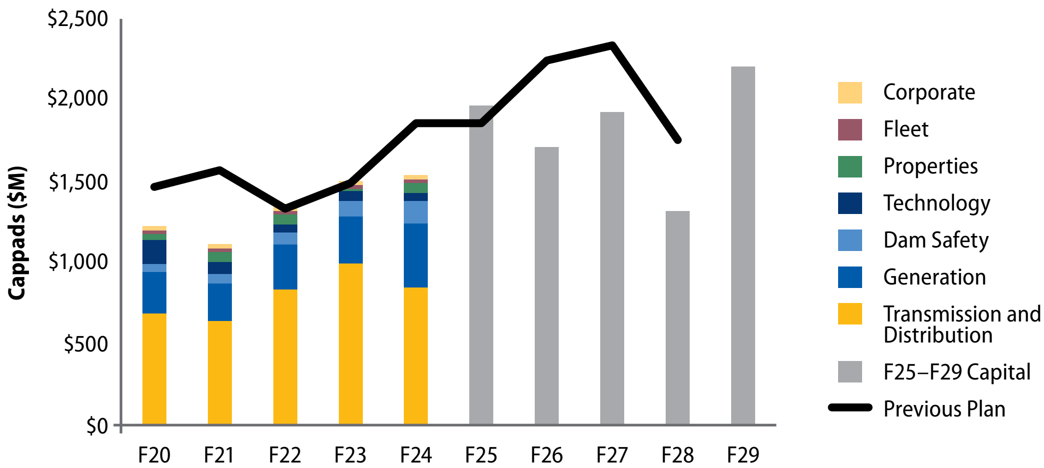
Investments also include projects for growth in the system as the provincial economy expands and the population grows. BC Hydro's 10-Year Capital Plan has been developed and is updated annually.

BC Hydro recovers the cost of its capital assets in rates over the useful life of the assets. Amortization of capital assets begins when the asset is put into service.

BC Hydro was planning capital additions totalling $18.5 billion between Fiscal 2020 and Fiscal 2029 under its 10-Year Capital Plan. BC Hydro undertook a review of the plan as part of the Review and will reduce these capital additions by $2.7 billion, from $18.5 billion to $15.8 billion over the 10-year period.

BC Hydro's Capital Plan includes five years of investment-level detail covering Fiscal 2020 through Fiscal 2024, and a high level projection for Fiscal 2025 to Fiscal 2029. The figure below compares the capital additions from the prior plan with the revised plan described above.

Figure 6: Comparison of Capital Additions in Current and Prior Capital Plans



Note: "Fleet" refers to BC Hydro's vehicle fleet

Of the $2.7 billion reduction in capital additions over the 10-year period, approximately:

- $1.6 billion results from a reduction of sustainment expenditures over the ten-year period, relative to previously planned amounts;
- $0.5 billion relates to the postponement of transmission and distribution projects that are no longer required on the same schedule due to changing load forecast projections; and
- $0.6 billion relates to a change in the need for a sixth generating unit at the Revelstoke generating facility, shifting the forecast in-service date of the project to 2030.

BC Hydro has carefully considered system impacts to ensure that risks to safety and reliability will be managed by targeting remaining investments in its most critical and/or highest risk assets. Investments needed to meet minimum legal, regulatory or tariff compliance requirements will not be reduced.

BC Hydro continues to refine the appropriate balance between asset life, system performance and affordability and believes that by appropriately timing expenditures we will provide more value to both current and future customers.

The 10-Year Capital Plan is informed by BC Hydro's load forecast which will be released in 2019 as part of the Revenue Requirements Application to be filed with the BCUC in February 2019.

The electrification required to meet the targets in the CleanBC plan will increase electricity demand. It is expected that this increase in electricity demand can be mostly met with existing and planned resources and will be further examined as part of Phase 2 of the Review. BC Hydro will consider the outcomes of the second phase of the Review in future annual capital plan updates.

The BCUC will review BC Hydro's capital projects going forward that require a Certificate of Public Convenience and Necessity or are filed under Section 44.2 of the *Utilities Commission*

Act. This excludes those projects that have already been provided with exemptions, or may be exempted in the future because they support certain policy objectives. The BCUC also has the opportunity to review all forecast capital expenditures and additions through BC Hydro's Revenue Requirements Applications.

The BCUC is currently reviewing its regulatory framework with respect how it provides oversight on BC Hydro's capital projects. BC Hydro is participating in this proceeding and a BCUC decision is expected in 2019.

As requested by the BCUC, BC Hydro will file a report regarding the potential applicability of performance-based regulation (PBR) for BC Hydro when it files its upcoming Revenue Requirements Application. Under the current cost of service regulatory framework, the BCUC seeks information to review costs for prudency. Under PBR, for certain costs (possibly including some capital and operating costs), base year costs are set and then adjusted via a formula in future years, including incentives for efficiencies. PBR is used to regulate various utilities in Canada, though there are limited instances in which it is used for Crown corporations. The BCUC will decide whether PBR is an appropriate approach for regulation of BC Hydro.

4.2.4 Tightly Manage Controllable Operating Costs

Over the five-year rates forecast period from Fiscal 2020 to Fiscal 2024, BC Hydro faces increases in projected incremental operating costs due to the Employer Health Tax, pension cost adjustments mandated by the BCUC, labour costs stemming from the upcoming collective bargaining mandate, storm restoration costs and anticipated increases in school property taxes. These incremental costs are partially offset by the elimination of Medical Service Plan premiums.

In addition to the sustained reductions to operating costs made from prior reviews (see section 2.1), BC Hydro will make reductions to other operating costs over the same period to help partially offset operating cost pressures that it is facing. Some of these reductions are a result of process improvements and lower spending on specific projects and initiatives, while others will come from labour utilization savings and further reductions are due to the impact of accounting treatment changes.

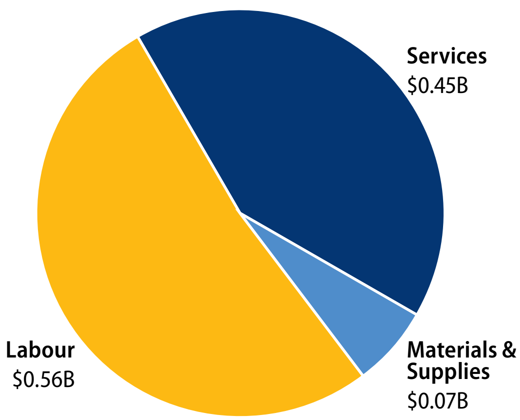
For example, process improvements such as the Enterprise Billing project achieve cost savings by reducing costs through paperless billing and lowering the volume of bill inquiries. BC Hydro will realize savings in future years from the Supply Chain Applications project that is underway and also from its decision to insource certain services that were previously provided by Accenture. BC Hydro has also achieved forecast savings through more efficient use of labour budgets, the elimination of a property lease and lower communications budgets.

BC Hydro's operating cost plan going forward balances affordability for ratepayers, while also making investments in its system.

BC Hydro expects to be able to limit its base operating cost increases below the projected rate of inflation over the five-year rates forecast period. These operating costs will be reviewed by the BCUC as part of the upcoming Revenue Requirements Application proceeding. A further breakdown of BC Hydro's operating costs and how these costs are trending is provided below.

Figure 7: Breakdown of Base Operating Costs in Fiscal 2019 Plan

F2019 Plan Base Operating Cost = $0.77B



Total F2019 Plan Base Operating Costs:

Labour, Services, Materials & Supplies	$1.08B
Capital Overhead	(0.29)B
Recoveries	(0.07)B
Total Plan Operating Costs	**$0.77B**

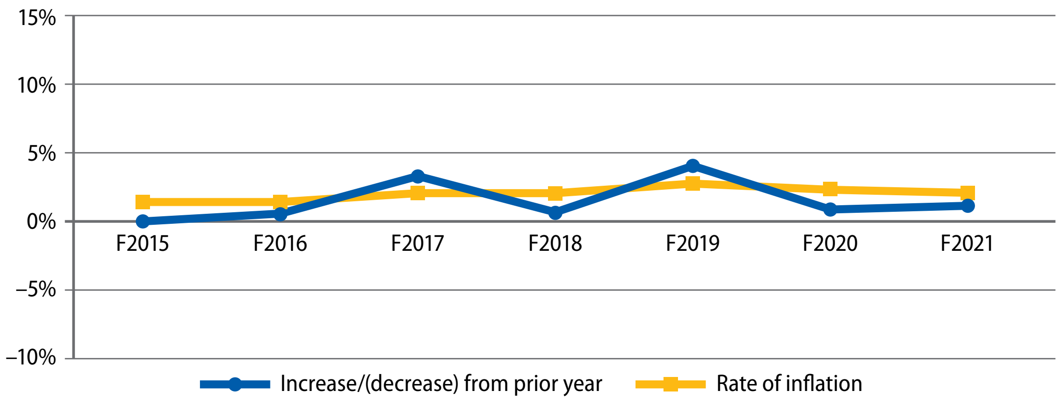
- ***Labour*** *includes personnel costs including salary, wages and benefits for BC Hydro internal labour workforce.*
- ***Services*** *includes costs such as contractor and consulting services, power purchase arrangements treated as leases, insurance, dues and fees, communication and utilities, building and property rent.*
- ***Materials and Supplies*** *include costs such as materials (e.g., connectors, brackets, splitters, batteries, tubing), computer software, office supplies and miscellaneous supplies.*

Within Public Sector Employers Council (PSEC) rules, BC Hydro seeks to provide inflationary wage/salary increases to its staff. When purchasing services and materials from third parties, these costs are also subject to inflation.

Base Operating Costs Trend

Despite inflationary pressures noted above, Figure 8 shows that BC Hydro has been able to limit increases in its base operating costs below inflation in recent years as a result of prudent management and continuous improvement.

Figure 8: BC Hydro Base Operating Cost Trend



1. *Rate of Inflation - Fiscal 2015 to Fiscal 2018 source www.bcstats.gov.bc.ca produced by BC Stats January 2018 (by fiscal year end).*
2. *Rate of Inflation - Fiscal 2019 – F2021 source Consumer Price Index assumptions from Treasury Board, October 5, 2018.*
3. *F2019 includes a $10 million (approx. 1.3%) increase stemming from how BCUC directed BC Hydro to forecast pension costs for rate setting purposes. The actual change in costs may be different and will be known at the end of the fiscal year.*

BC Hydro's average base operating cost increase over the Fiscal 2015 to Fiscal 2021 period is 1.50%, which is 0.44% below the average rate of inflation of 1.94% for the same time period.

4.2.5 Increase Revenues

Increase revenues through sale of Low Carbon Fuel Standard (LCFS) credits

Under the *Greenhouse Gas Reduction (Renewable & Low Carbon Fuel Requirements) Act* and the Renewable and Low Carbon Fuel Requirements Regulation (the Regulation), transportation fuel suppliers in British Columbia must, among other obligations, progressively decrease the average carbon intensity of their fuels to achieve a 10% reduction in 2020 relative to 2010. Further increases in stringency to achieve a 20% reduction in carbon intensity by 2030 were announced in December 2018 as part of the CleanBC plan. Under the current Regulation, fuel suppliers select their own approach for compliance with this requirement. Fuel suppliers can:

- supply more low carbon fuels;
- acquire credits through a Part 3 Agreement; and/or
- trade credits with other suppliers.

The Ministry of Energy, Mines and Petroleum Resources is currently undertaking a review of the LCFS program. As part of this review, regulatory and legislative changes could increase the number of LCFS credits available for sale. If adopted, these changes would generate incremental revenues for Powerex and its parent, BC Hydro, between Fiscal 2020 and Fiscal 2024. This incremental revenue would be incorporated in future rate forecasts.

Work to attract additional customers and increase electricity demand

Phase 1 of the Review explored opportunities to increase electricity demand. BC Hydro continues to forecast that it will have an energy surplus, even with the changes in the future of energy procurement resulting from the Review. Today, BC Hydro sells that surplus into export markets.

BC Hydro is pursuing strategies to grow domestic electricity demand. As part of this, BC Hydro is exploring the option to offer current industrial customers year-round access to real time, market-based pricing for incremental energy purchases. For example, during the freshet period, there are high inflows into BC Hydro's reservoirs, resulting in surplus electricity generation that could potentially be sold at a discounted rate to industrial customers.

BC Hydro is engaging with stakeholders and customers on these options and expects to file an application with the BCUC in 2019 regarding real time market-based pricing. If any of these strategies are approved by the BCUC, the impacts would be incorporated in future rates forecasts.

5. Five Year Rates Forecast

Based on the outcomes of Phase 1 of the Review, BC Hydro's rates forecast covering the five-year period from Fiscal 2020 to Fiscal 2024 would result in an estimated cumulative increase in customer bills of 8.1%. This increase is almost 40% lower than the cumulative target increases of 13.7% in the previous government's 10 Year Rates Plan. It is also approximately 20% lower than the forecast increase in inflation of 10.7% over the same time period and helps to keep electricity bills affordable for customers.

The forecast bill impact of 1.8% in Fiscal 2020 is a result of a forecast rate increase of 6.8% for that year, offset by an expected reduction in the DARR from 5% to 0%.

Table 4: BC Hydro Five Year Rates Forecast

	Fiscal 2020	Fiscal 2021	Fiscal 2022	Fiscal 2023	Fiscal 2024	Cumulative Five Years*
Current Rates Forecast – Annual Rate Increase before reducing the DARR	6.8%	0.7%	2.2%	0.0%	3.2%	n/a
Current Rates Forecast – Annual Bill Impact – including reduction in DARR**	1.8%	0.7%	2.2%	0.0%	3.2%	8.1%
Previous Govt's 10 Year Rates Plan – Annual Bill Impact	2.6%	2.6%	2.6%	2.6%	2.6%	13.7%
Forecast BC Inflation	2.3%	2.0%	2.0%	2.0%	2.0%	10.7%

* *Cumulative rates do not equal the sum of individual rate changes shown for each year due to the effect of compounding.*

** *after reducing the Deferral Account Rate Rider (DARR) from 5% to 0%, beginning in Fiscal 2020. Under the 2013 10 Year Rates Plan, the DARR was set at 5% indefinitely – it was expected to remain at 5% at least through Fiscal 2024. Going forward, the BCUC will now determine how the DARR is set and applied. This change is explained further in section 4.1.3.*

Under the new regulatory model for BC Hydro, rate increases will be determined by the BCUC in future revenue requirements proceedings. That means that future rate increases may be lower or higher than the rates forecast shown above. BC Hydro intends to make all reasonable efforts to maintain rate increases within the projected rates forecast.

6. Next Steps

Government is implementing the changes to ensure sound financial and regulatory oversight of BC Hydro and to keep rates affordable for customers. The outcome of Phase 1 will also inform Phase 2 of the Comprehensive Review, which will focus on transformational aspects to changing energy markets. This second phase will be informed by new government strategies, including the CleanBC plan, and will provide a strategic and long-term view of the future role of BC Hydro.

Phase 1 of the Review also supports BC Hydro in filing its next Revenue Requirements Application with the BCUC. Through this open and transparent regulatory process, stakeholders and the public will be able to comment on BC Hydro's costs, spending and electricity rates.

Government remains committed to keeping electricity rates affordable for British Columbians and positioning BC Hydro for success in the years ahead.

Appendix A:
Phase 1 Terms of Reference

Terms of Reference

2018 Comprehensive Review of BC Hydro – Phase 1

Context

Under the Minister of Energy, Mines and Petroleum Resources' Mandate Letter, the ministry is required to undertake a comprehensive review of BC Hydro, and work with BC Hydro to develop a refreshed plan to keep rates low and predictable over the long-term.

The ministry has received direction to undertake a two-part review. The first part is to focus primarily on BC Hydro's costs and rates, including creating the refreshed plan for rates, and will assist BC Hydro in preparing a Revenue Requirements Application to be filed with the BC Utilities Commission in February 2019.

The second part will focus on transformational aspects to changing energy markets, and respond to the expected Energy Road Map for BC and assist BC Hydro in developing its Integrated Resource Plan in 2019. Terms of reference for this second part will be finalized after the first part of the review has been completed. The remainder of this document focuses on the first part of the review.

Objective

BC Hydro and ministry staff will develop options for consideration to support a new 10 Year Rates Plan, with the ultimate goal of reducing the growth in BC Hydro's electricity rates and ensuring sound financial and regulatory oversight of BC Hydro. The Advisory Group will provide advice and analysis by assessing options and the actions required to achieve them.

Membership

An Advisory Group consisting of staff from BC Hydro, the Ministry of Finance and the Ministry of Energy, Mines and Petroleum Resources (EMPR) will perform the first phase of the review. The Advisory Group may consult with BC Utilities Commission staff.

Advisory Group Co-chairs

- Assistant Deputy Minister, Electricity and Alternative Energy Division, Ministry of Energy, Mines and Petroleum Resources
- A/Chief Financial Officer, BC Hydro

Governance/Accountability

The Advisory Group will report monthly to the Steering Committee. The Steering Committee will provide feedback and advice on options and recommendations to Ministers.

Steering Committee Membership

- Deputy Minister, Ministry of Energy, Mines and Petroleum Resources
- Deputy Minister, Ministry of Finance
- President and COO, BC Hydro
- Executive Chair, BC Hydro

Timeline

The Advisory Group, based on advice from the Steering Committee, will prepare options and recommendations for consideration by Ministers by summer 2018.

A report on the first phase of the review, and Government's response, will be released in the fall of 2018. The report will describe the areas of BC Hydro's finances, programs and operations, that were examined during the review, and decisions by government in response to the Advisory's Group's recommendations.

The report will also inform BC Hydro's next rate application, which will be filed with the B.C. Utilities Commission (BCUC) in early 2019. During the BCUC's review of that application, stakeholders and the public will have a further opportunity to see and comment on how the outcomes of the first phase of the BC Hydro review have influenced BC Hydro's finances, and electricity rates.

Areas of Focus

The Advisory Group has identified the following areas of focus, which include the key components of BC Hydro's revenue requirements, known items that need to be resolved, BCUC feedback from their decision of the Fiscal 2017 – Fiscal 2019 Revenue Requirements Application, and other issues that have been identified:

1. Revenues / Load Forecasting
2. Cost of Energy
3. Operating Costs and other issues
4. 10 Year Capital Plan (excluding Site C)
5. Regulatory Accounts
6. Demand-Side Management
7. Water Rentals
8. Net Income and Dividends
9. Legal Considerations
10. Customer Affordability / Rates
11. Powerex
12. Financial Forecasting (i.e., impact of all of the above on future rates)
13. Debt/Cash Management
14. Enterprise Risk Management

APPENDIX B: FOCUS AREAS OF THE REVIEW

Regulatory Accounts

Work in this area examined the historical context of regulatory accounts, forecast balances and current accounts. Regulatory accounts are commonly used by utilities. They represent costs not yet recovered from, or revenues not yet refunded to, BC Hydro ratepayers. BC Hydro uses regulatory accounts to match costs with benefits for customers, to capture differences between forecast and actual costs and revenues typically related to uncontrollable factors (e.g., interest rates, water inflows, storm restoration costs), to smooth rate increases over time and to manage the impact to ratepayers of changes in accounting rules. As of September 30, 2018, BC Hydro had 29 regulatory accounts with a balance of approximately $4.8 billion.

Work in this area also focused on empowering the BCUC to exercise oversight and make decisions on all future costs and regulatory accounts on a go-forward basis, while ensuring that BC Hydro could continue recovering costs related to previous policy decisions. This area also explored the write-off of the balance of the Rate Smoothing Regulatory Account.

Cost of Energy Acquisition

Work in this area included an assessment of the current cost to ratepayers of energy acquisition programs and how those costs could be reduced in future. Since the ability to manage cost of energy is largely limited to potential biomass Electricity Purchase Agreement renewals and the Standing Offer Program, actions focused on these programs.

Operating Costs

Work in this area examined current base operating costs and forecast future operating cost pressures and savings.

In recent years, BC Hydro has limited the growth in its base operating costs. For example, in its last Revenue Requirements Application, BC Hydro limited its proposed base operating cost increases to below forecast B.C. inflation. These operating costs were approved by the BCUC.

Over the five-year rate forecast period from Fiscal 2020 to Fiscal 2024, BC Hydro faces increases in projected incremental operating costs. These incremental costs are partially offset by the elimination of Medical Service Plan premiums. BC Hydro will make further reductions to contain operating costs over the five-year rate forecast period and, as a result, focuses its efforts to be able to limit its base operating cost increases below the forecast rate of inflation over the Fiscal 2020 to Fiscal 2024 period. Further review of operating costs by the BCUC and interveners will occur in 2019 as part of BC Hydro's next Revenue Requirements Application process.

Capital Plan

Work in this area focused on an updated capital plan as well as asset retirements, dismantling costs and write-offs.

BC Hydro is spending over $2 billion annually on capital projects. BC Hydro recovers the cost of its capital assets in rates through amortization that is included in its revenue requirements. Amortization of capital assets starts when the asset is put into service.

BC Hydro's 10-year Capital Plan is updated annually to ensure that the existing electricity system continues to perform safely and reliably and that upgrades and new facilities are added in time to meet projected growth in electricity demand.

Revenues/Load Forecasting

Work in this area examined sector assumptions, electrification scenarios, new revenue streams, as well as restoring the regulatory oversight and a new timeline for the Integrated Resource Plan.

BC Hydro forecasts its revenues from electricity sales based on the forecasting of load, or demand, for electricity. Forecasting load over the long term is inherently uncertain as it is difficult to predict future trends related to economic and population growth, energy efficiency and technology. In recognition of this uncertainty, BC Hydro plans over a longer term within uncertainty ranges.

As a cost of service utility, BC Hydro's requested revenue requirement is designed to equal its expected costs. Revenues have two components: the rate and the amount of electricity sold. Estimating the amount of electricity that will be sold – the load forecast – is a critical component to determining the rate.

The load forecast for the Fiscal 2017 – Fiscal 2019 Revenue Requirements Application was developed in May 2016. Actual results since May 2016 have closely tracked the May 2016 Load Forecast, falling within 0.5%to 0.7% of actuals for Fiscal 2017 and Fiscal 2018. Nevertheless, BC Hydro's load forecast has since been the subject of a number of reviews, including the 2017 Load Forecast Internal Audit, the Fiscal 2017 – Fiscal 2019 Revenue Requirements Application Decision and the Site C Inquiry Final Report. In response to these reviews and as part of BC Hydro's continuous improvement efforts, BC Hydro has made changes to its load forecast methodology. Key concerns expressed by the BCUC and the BC Hydro's internal audit review have now been addressed. For example, the Five-Year Load Forecast that will be part of BC Hydro's next Revenue Requirements Application reflects the results of a new price elasticity study and modified approach to forecasting demand from Liquefied Natural Gas.

Dividends & Net Income

Work in this area included the setting of BC Hydro's allowed net income, including how to transition this responsibility to the BCUC.

BC Hydro's net income forms part of the government's revenue for Provincial budget purposes. Under the previous 2013 10 Year Rates Plan, BC Hydro's allowed net income was set by government and BCUC was required to approve the set amounts. Typically, a utility's allowed net income is set by its regulator to balance ratepayer and shareholder interests. As a result of the Review, the BCUC will set BC Hydro's allowed net income for rate-setting purposes after a two-year transition period.

BC Hydro's dividend payments provide cash flow to the government and allow the government to reduce its debt requirements. Dividend payments do not directly impact the government's fiscal surplus/deficit, but do impact taxpayer-supported borrowing requirements. Under current government regulation and policies, BC Hydro's dividend for the current fiscal year will be $59 million and $0 thereafter until such time as BC Hydro achieves a 60:40 debt:equity ratio, which is more typical for utilities than BC Hydro's current ratio of approximately 80:20. The approach to dividends will not change at this time as a result of the Review.

Powerex

Work in this area focused on BC Hydro's subsidiary, Powerex, and how it contributes to ratepayer value through its net income. The area also examined the potential to increase Powerex net income through the sale of renewable energy credits.

Powerex is a key participant in energy markets across North America, buying and selling wholesale power, renewable and low-carbon energy and products, natural gas, ancillary services and financial energy products. Powerex's trade activities earn income to lower BC Hydro's customer rates and to help balance its system by being able to import energy to meet domestic demand when there is a supply shortage and exporting energy when there is a supply surplus. Exports are made only after ensuring domestic demand requirements are met.

Demand Side Management

Work in this area examined BC Hydro's demand-side management activities, including its Power Smart programs.

Demand Side Management is an important part of BC Hydro's resource plan, providing the flexibility to meet future supply needs or build efficient load, depending on system needs. Demand Side Management is a low-cost energy resource with little to no environmental impact. This area was examined, and, consistent with the government's focus on affordability, in its upcoming Revenue Requirements Application, BC Hydro will be proposing to increase the amount of spending for the residential sector and low-income ratepayers, while keeping Demand Side Management expenditures at the same level overall.

Water Rentals

Work in this area examined water rentals paid by BC Hydro to the government and whether these charges are appropriate going forward, as well as elements of the *Water Sustainability Act*.

Water Rentals are the fees charged by the government for using its water for hydroelectric production. Water Rental rates for commercial and general power licenses are set by the Water Sustainability Fees, Rentals and Charges Tariff Regulation under the *Water Sustainability Act*. There were no decisions for this area coming out of Phase 1 of the Review.

Other Areas Examined

Debt/Cash Management, Financial Forecasting, Customer Rates and Proactive Enterprise Risk Management were all examined with no additional decisions in these areas coming out of Phase 1 of the Review.

Regulatory Considerations

Work in this area included considering the regulatory implications of the outcomes of the Review and determining how best to implement them. Further information is provided in Appendix D.

Appendix C:
Summary of BCUC Oversight

Area of Focus	Previous Regulatory Oversight	Regulatory Oversight after the Review	Change in Reg. Oversight
Regulatory Accounts	Direction for some	Recover existing balances in rates and BCUC go-forward oversight for almost all accounts	↑
Integrated Resource Plan	No BCUC review	BCUC reviews	↑
Rate Smoothing	BCUC determines after Fiscal 2019	RSRA written off in Fiscal 2019	↑
Rate Setting	Under prescribed cap	BCUC decides	↑
Deferral Account Rate Rider (DARR)	Set at 5% by Direction	BCUC decides	↑
Net Income for rate-setting	Set at $712M by Direction	Set by government at $712M in Fiscal 2020 and Fiscal 2021, then BCUC decides	↑
Biomass Renewals	BCUC determines if new EPAs are in the public interest	Government to provide Direction	↓
Standing Offer Program	Required under *Clean Energy Act*; no prescribed circumstances	Regulation specifies prescribed circumstances that enable indefinite suspension	↔
Rate Rebalancing	Direction to BCUC prohibits	Regulation prohibits unless BC Hydro requests	↔
Expenditures for Export	Direction to BCUC	BCUC to refrain from considering when determining BC Hydro's rates	↔
Powerex	Direction to BCUC	Continues to restrict the BCUC from regulating the activities of Powerex	↔
Retail Access	Direction to BCUC prohibits	Regulation prohibits unless BC Hydro requests	↔

Appendix D:
Summary of New Regulations and Legislation

Regulations:

Integrated Resource Plan
Clean Energy Act: Change of deadline for the IRP
Direction No. 8 to the BCUC
Repeals Directions No. 1,3,6,7 and replaces Direction 7
Prohibits BCUC from disallowing recovery of current regulatory account balances
Allows BC Hydro to recover interest costs on funds borrowed in relation to Rate Smoothing Regulatory Account
Net income: set at $712M for Fiscal 2020 and Fiscal 2021 . In Fiscal 2022 and beyond, BCUC to set allowed net income
Continues existing provisions that limit retail access, rate rebalancing and expenditures for export
Continues to restrict the BCUC from regulating Powerex
Energy Procurement
Indefinite suspension of the Standing Offer Program
Biomass Energy Program: Program direction and required cost recovery (regulation under development)
Financial Directives
Repeal Treasury Board Regulation 257/2010 that exempted BC Hydro from the requirement that rates be set by an independent, third party regulator for rate regulated accounting. Occurred October 2018.
Write off of the Rate Smoothing Regulatory Account (Timing TBC)

Legislative Changes (under development):

IRP timing and oversight
Prohibition of rate rebalancing
Utilities Commission Act does not apply to Powerex
Remove concept of expenditures to export from *Clean Energy Act*
Streamlining of the *Clean Energy Act* (i.e. removing clauses that no longer apply)

Appendix E: Acronyms, Abbreviations and Definitions

10 Year Rates Plan	The 2013 10 Year Rates Plan covered Fiscal 2015 – Fiscal 2024 and had three main components: BC Hydro actions to reduce costs; government actions; and the creation of a Rate Smoothing Regulatory Account.
Auditor General	An independent Officer of the Legislature, who, under a fixed term of office in legislation, has a mandate to conduct audits and performance reviews of government entities, with the intention to report on how well government is managing its responsibilities and resources.
BC Hydro	British Columbia Hydro and Power Authority. A provincial Crown corporation that operates an integrated system of generation, transmission and distribution infrastructure to deliver reliable, affordable and clean electricity to its customers, safely.
BCUC	British Columbia Utilities Commission. The BCUC works to ensure British Columbians get value from their utilities with safe, reliable energy services, while also ensuring the owners of the entities it regulates are able to earn a fair return on their invested capital.
capacity	The maximum sustainable amount of electricity that can be produced or delivered at any instant. Typically measured in kW, MW or GW.
CleanBC plan	The CleanBC plan is the Province's strategy to reach its 2030 climate targets, through the use of clean and renewable energy in transportation, buildings and industry in order to reduce greenhouse gas emissions and build British Columbia's economy.
Clean Energy Act	Passed in 2010, this legislation set the foundation for a new future of electricity self-sufficiency, job creation and reduced greenhouse gas emissions, powered by unprecedented investments in clean, renewable energy across British Columbia.
Crown corporation	Crown corporations are public sector organizations established and funded by the B.C. government to provide specialized goods and services to citizens. They operate at varying levels of government control and report on their planning, governance and accountabilities. BC Hydro is a Crown corporation.
DARR	Deferral Account Rate Rider. Surcharge (currently 5%) that applies to all charges on customer bills, excluding taxes and levies. Funds collected under the DARR were intended to be used to pay down BC Hydro's three energy deferral account balances (the Heritage Deferral Account, the Non-Heritage Deferral Account and the Trade Income Deferral Account).
Demand Side Management	BC Hydro's programs that support energy conservation and encourage the adoption of more energy efficient products and equipment.
dividend	BC Hydro's dividend payments provide cash flow to the government and allow the government to reduce its borrowing requirements. BC Hydro's dividend for the current fiscal year will be $59 million and will be $0 thereafter until such time as BC Hydro achieves a 60:40 debt:equity ratio.
Electricity Purchase Agreement	A commercial agreement that sets out the terms and conditions under which a buyer purchases electricity from a supplier

energy	How much is consumed or produced over a period of time
expenditures for export	To ensure the costs of pursuing such opportunities for electricity export were not passed along to the ratepayer, the *Clean Energy Act* required the BCUC to ensure that BC Hydro's rates would not allow BC Hydro to recover "expenditures for export."
government	Government of British Columbia
***Greenhouse Gas Reduction (Renewable & Low Carbon Fuel Requirements) Act* and Renewable and Low Carbon Fuel Requirements Regulation**	Requires transportation fuel suppliers in B.C. to progressively decrease the average carbon intensity of their fuels to achieve a 10% reduction in 2020 relative to 2010.
Heritage assets	Defined in the *Clean Energy Act* to include all of the transmission and distribution infrastructure in place when the Act was passed as well as those generating facilities identified in Schedule 1 to the Act.
GWh	A unit of energy, where 1 MWh is the amount of energy produced from a generator operating at 1 MW capacity for a period of 1 hour 1 gigawatt hour = 1,000 MWh
IFRS	International Financial Reporting Standards
Impact Benefit Agreement	An agreement between BC Hydro and a First Nation to address adverse impacts arising from the construction of BC Hydro's projects that cannot be avoided, mitigated or otherwise accommodated.
IPP	Independent Power Producer
IRP	Integrated Resource Plan
load	Demand for electricity, measured in terms of energy (MWh or GWh) and capacity (MW or GW)
load forecast	Estimates the amount of electricity that will be sold. The load forecast is a critical component to determining BC Hydro's rates.
load offset	Energy generated by a BC Hydro customer at its customer site to offset the energy the customer currently purchases from BC Hydro to serve its own needs.
LCFS credits	Low Carbon Fuel Standard credits
MW	A unit of energy generating capacity 1 megawatt = 1,000 kilowatts = 1 million watts
net income	The return that BC Hydro is allowed to earn in a given year. BC Hydro's net income forms part of the government's revenue for government budget purposes.
PBR	Performance based regulation. Under PBR, for certain costs base year costs are set and then adjusted via a formula in future years, including incentives for efficiencies.
Powerex	Powerex Corp. BC Hydro subsidiary and a key participant in energy markets across North America, buying and selling wholesale power, renewable and low-carbon energy and products, natural gas, ancillary services and financial energy products.

rate rebalancing	Increasing or decreasing rates for each customer class by a different amount in order to align the revenues received from each class with the cost the utility incurs to serve each class
Rate Smoothing Regulatory Account	Established in 2014 as a result of government direction. Used to smooth the higher annual rate increases that would have been required to cover BC Hydro's costs in the early years of the 2013 10 Year Rates Plan by enabling BC Hydro to defer collection of revenues from ratepayers to the later years of the Plan.
retail access	Ability for customers to secure electricity from the market via a third-party provider rather than the local utility
regulatory accounts	BC Hydro uses regulatory accounts to match costs with benefits for customers, to capture differences between forecast and actual costs and revenues typically related to uncontrollable factors (e.g., interest rates, water inflows, storm restoration costs), to smooth rate increases over time and to manage the impact of changes in accounting rules.
Review	Comprehensive, two-phased review of BC Hydro, first phase commenced in June 2018 and completed with the release of this report. Second phase to commence in 2019.
revenue requirements	BC Hydro's forecasts of the revenue that it needs to collect from its customers in order to cover its costs.
Revenue Requirements Application	Application to the BCUC in which BC Hydro proposes the revenue it needs to collect in order to cover its costs. BC Hydro's most recent Revenue Requirements Application was for Fiscal 2017 – Fiscal 2019.
RNG	Renewable Natural Gas
Utilities Commission Act	The BCUC operates under and administers this Act. BC Hydro is a public utility under this Act.
water rental rates	Fees charged by the government for using its water for hydroelectric production
Water Sustainability Fees, Rentals and Charges Tariff	Water Rental rates for commercial and general power licenses are set by this Regulation under the *Water Sustainability Act*

Notes

Appendix C

BRITISH COLUMBIA

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix D

Government Regulations

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 051 , *Approved and Ordered* February 14, 2019

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that

(a) Direction to the British Columbia Utilities Commission Respecting the Iskut Extension Project, B.C. Reg. 137/2013, is amended as set out in section 1 of the attached Appendix A,

(b) Special Direction No. 9 to the British Columbia Utilities Commission, B.C. Reg. 157/2005, is amended as set out in section 2 of the attached Appendix A,

(c) Direction No. 1 to the British Columbia Utilities Commission, B.C. Reg 105/2009, is repealed,

(d) Direction No. 3 to the British Columbia Utilities Commission, B.C. Reg. 105/2012, is repealed,

(e) Direction No. 6 to the British Columbia Utilities Commission, B.C. Reg. 29/2014, is repealed, and

(f) Direction No. 7 to the British Columbia Utilities Commission, B.C. Reg. 28/2014, is repealed and Direction No. 8 to the British Columbia Utilities Commission, set out in the attached Appendix B, is made.

DEPOSITED

February 14, 2019

B.C. REG. 24/2019

Minister of Energy, Mines and Petroleum Resources

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, ss. 3 and 22

Other: OIC 1107/2003; OIC 2015/2009; OIC 314/2012; OIC 96/2014; OIC 97/2014; OIC 182/2013

R20257527

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APPENDIX A

1 *Section 4 (1) of Direction to the British Columbia Utilities Commission Respecting the Iskut Extension Project, B.C. Reg. 137/2013, is repealed.*

2 *Section 2.1 of Special Direction No. 9 to the British Columbia Utilities Commission, B.C. Reg. 157/2005, is repealed.*

APPENDIX B

DIRECTION NO. 8 TO THE BRITISH COLUMBIA UTILITIES COMMISSION

Contents

Definitions

1 In this direction:

"Act" means the *Utilities Commission Act*;

"deemed equity" means, for any fiscal year, the product obtained by multiplying the rate base relating to that year by 30%;

"distributable surplus" has the same meaning as in Heritage Special Directive No. HC1 to the British Columbia Hydro and Power Authority;

"DSM regulatory account" means the regulatory account of the authority established under commission order G-55-95;

"F2020" means the authority's fiscal year commencing April 1, 2019 and ending March 31, 2020;

"F2021" means the authority's fiscal year commencing April 1, 2020 and ending March 31, 2021;

"rate smoothing regulatory account" means the rate smoothing regulatory account approved by commission order G-48-14;

"rate base" means, in relation to a fiscal year of the authority, the amount determined in accordance with the following equation and notes:

$$RB = WCA + (A + B + C)/2 - (D + E + F)/2$$

where

RB	=	rate base;
WCA	=	working capital amount of $250 million;
A, B, D, E and F	=	the sum of an amount the authority forecasts will be listed as follows in the authority's audited financial statements at the end of the previous fiscal year and the amount the authority forecasts will be similarly listed at the end of the applicable fiscal year:
A		is the amount listed as property, plant and equipment in service, less accumulated amortization;
B		is the amount listed as intangible assets in service, less accumulated amortization;
D		is the amount listed as contributions in aid of construction;
E		is the amount listed as contributions arising from the Columbia River Treaty;
F		is the amount listed as leased assets included in A, less accumulated amortization;
C	=	the sum of the balance the authority forecasts for DSM regulatory account at the beginning of the fiscal year and the balance the authority forecasts for the same account at the end of the fiscal year.

Notes:

1 In determining rate base for a fiscal year, the amounts A, B and F must have subtracted from them any amount included in them that is an expenditure incurred by the authority, on or after April 1, 2011, that the commission determines under the Act must not be recovered by the authority in rates.

2 In determining rate base for a fiscal year, the amount D must have subtracted from it any amount included in it that is related to an expenditure referred to in note 1.

Application

2 This direction is issued to the commission under section 3 of the Act.

Basis for establishing authority revenue requirements

3 In regulating and setting rates for the authority for F2020 and F2021, the commission must ensure that those rates allow the authority to collect sufficient revenue in each fiscal year to enable the authority to achieve an annual rate of return on deemed equity that would yield a distributable surplus of $712 million.

Cost recovery

4 (1) In setting rates for the authority, the commission must not disallow for any reason the recovery in rates of the balance of the authority's regulatory accounts as at March 31, 2019 and the costs incurred by the authority with respect to the following:

(a) the construction of extensions to the authority's plant or system that came into service before April 1, 2016;

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(b) energy supply contracts entered into before April 1, 2016;

(c) debt servicing costs on amounts borrowed in relation to the rate smoothing regulatory account.

(2) Subsection (1) (c) does not limit the power of the commission to allow the recovery in rates of debt servicing costs related to the authority's regulatory accounts not referred to in that subsection.

Rate rebalancing

5 In setting rates for the authority for F2020 and F2021, the commission must not set rates for the purpose of changing the revenue-cost ratio for a class of customers.

Expenditures for export

6 The commission must not comply with section 4 (5) of the *Clean Energy Act* when setting rates for the authority for F2020 and F2021.

Retail access

7 Except on application by the authority, the commission must not set rates for the authority that would result in the direct or indirect provision of unbundled transmission services to retail customers in British Columbia, or to those who supply such customers.

Powerex

8 The commission may not exercise any power or perform any duty under Part 3 of the Act in regard to Powerex Corp.

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 052 *, Approved and Ordered* February 14, 2019

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the Standing Offer Program Regulation, B.C. Reg. 320/2010, is amended as set out in the attached Schedule.

DEPOSITED

February 14, 2019

B.C. REG. 23/2019

Minister of Energy, Mines and Petroleum Resources

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Clean Energy Act*, S.B.C. 2010, c. 22, ss. 15 and 35

Other: OIC 697/2010

R20270227

SCHEDULE

1 *The Standing Offer Program Regulation, B.C. Reg. 320/2010, is amended by adding the following section:*

Prescribed circumstance

4 (1) In this section, **"applicable facility"** means an eligible facility used in relation to the fulfillment of obligations under an electricity purchase agreement entered into by the authority under the standing offer program.

(2) For the purposes of section 15 (2) of the Act, a prescribed circumstance is that the aggregate nameplate capacity of all applicable facilities equals or exceeds 100 megawatts.

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 743 , *Approved and Ordered* December 10, 2018

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the following regulation is made:

BC HYDRO INTEGRATED RESOURCE PLAN REGULATION

Prescribed submission date

1 For the purposes of section 3 (6) (b) of the *Clean Energy Act*, February 28, 2021 is prescribed as the submission date for an integrated resource plan.

DEPOSITED

December 10, 2018

B.C. REG. **266/2018**

Minister of Energy, Mines and Petroleum Resources

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Clean Energy Act*, S.B.C. 2010, c. 22, s. 35 (h)

Other:

R10252327

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PROVINCE OF BRITISH COLUMBIA

REGULATION OF TREASURY BOARD

Financial Administration Act

Treasury Board orders that Part 3 of the Government Organization Accounting Standards Regulation, B.C. Reg. 257/2010, is repealed.

DEPOSITED

November 7, 2018

B.C. REG. 231/2018

Oct. 31/2018
Date signed

Carole James
Approved: CHAIR, TREASURY BOARD

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Budget Transparency and Accountability Act*, S.B.C. 2000, c. 23, ss. 23 and 23.1; *Financial Administration Act*, R.S.B.C. 1996, c. 138, s. 4

Other:

R10271318

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B.C. Reg. 102/2012
O.C. 295/2012

Deposited May 15, 2012

This consolidation is current to April 17, 2018.

Link to Point in Time

Clean Energy Act

GREENHOUSE GAS REDUCTION (CLEAN ENERGY) REGULATION

[includes amendments up to B.C. Reg. 114/2017, March 22, 2017]

Contents

Definitions

1 In this regulation:

"Act" means the *Clean Energy Act*;

"eligible vehicle or machine" means

(a) a specified vehicle,

(b) a marine vehicle,

(c) an asphalt paver,

(d) a fracture pump unit,

(e) a mine haul truck, and

(f) a locomotive

that uses, as a fuel source, compressed natural gas or liquefied natural gas;

"heavy-duty vehicle" means a truck, other than a mine haul truck, or tractor-trailer with a manufacturer's gross vehicle weight rating of 11 793 kg or more;

"medium-duty vehicle" means a vehicle, including a waste-haulage truck, with a manufacturer's gross vehicle weight rating of more than 5 360 kg but less than 11 793 kg;

"non-bypass customer" means a customer of a public utility that receives service under a rate that is not specific to the customer;

"operating costs", in relation to a fuelling station or to distribution or storage infrastructure, means

(a) operating and maintenance expenses,

(b) electricity expenses,

(c) interest expenses,

(d) taxes, including property taxes,

(e) return on equity,

(f) extraordinary retirement costs, and

(g) amounts with respect to the depreciation of the

(i) capital costs,

(ii) construction carrying costs,

(iii) feasibility and development costs,

(iv) sustaining capital costs, and

(v) decommissioning and salvaging costs

determined with reference to the remaining service life of the fuelling station or distribution or storage infrastructure, as estimated by the commission in setting rates;

"safety guidelines" means safety guidelines adopted by the British Columbia Safety Authority;

"shore-side asset" means any of the following:

(a) boil-off gas recovery equipment;

(b) an LNG cryogenic loading manifold;

(c) an LNG cryogenic pipeline and vessel loading berth;

(d) an LNG cryogenic storage tank;

(e) an LNG measurement apparatus;

"specified vehicle" means a heavy-duty vehicle, medium-duty vehicle, school bus or transit bus;

"tanker truck load-out" means equipment for transferring liquefied natural gas from a storage tank to a liquefied natural gas tank trailer;

"undertaking period" means the period that ends on March 31, 2022.

[am. B.C. Regs. 235/2013, s. 1; 98/2015, s. 1; 214/2016, s. 1; 114/2017, s. 1.]

Prescribed undertakings

2 (0.1) In this section:

"contracted demand" means the total compressed natural gas and liquefied natural gas demand under take-or-pay agreements with the public utility during the undertaking period;

"early adopter vehicle or machine" means an eligible vehicle or machine, other than a vehicle referred to in subsection (3.1) (a), used primarily in a market segment set out in column 1 of the following table, if

(a) the contracted demand for the market segment does not exceed, in any of years 5 through 11 of the undertaking period, the annual amount set out in the corresponding row of column 2 of the table, or

(b) the total number of persons who receive grants or zero-interest loans does not exceed, in the undertaking period, the number set out in the corresponding row of column 3 of the table:

Column 1 Market Segment	Column 2 Contracted Demand (GJ)	Column 3 Number of Persons who Receive Grants or Zero-Interest Loans
Wholesale distribution of food or beverages by truck	100 000	5
Short-haul trucking between a port and any of a railway, warehouse or trucking depot	100 000	5
Medium-duty vehicle and heavy-duty vehicle leasing	100 000	5
Passenger transportation by charter bus, other than a transit bus or school bus	100 000	5
Package courier service by truck	200 000	5
Off-highway mine hauling by truck	1 million	3
Transportation of goods or passengers by rail	1 million	3
Dump truck services	100 000	5
Transportation of cement in cement-mixing trucks	100 000	5
Bucket and digger trucking services	100 000	5
Pipe cleaning or hydro-vacuum excavation trucking services	100 000	5
On-highway hauling in trucks with a manufacturer's gross vehicle weight rating of more than 36 000 kg	1 million	10
Off-highway earth excavation, grading and moving for construction or mining	1 million	5
Asphalt paving services	100 000	6
Fracture pump unit services	200 000	4
Shipping, passenger transportation or commercial services by marine vehicle that will use fuel purchased from a public utility	10 million	13
Street sweeping services	100 000	5

"major transportation corridor" means Highway 1, 3, 3A, 4, 5, 7, 16, 19, 33, 37, 91, 95, 97 or 99.

(1) Subject to subsection (3.3), a public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility provides, through an open and competitive application process,

(i) grants or zero-interest loans to persons in British Columbia for the purchase of an eligible vehicle or machine to be operated in British Columbia, or

(ii) grants to persons in British Columbia

(A) to implement safety practices, or

(B) to improve maintenance facilities

to meet safety guidelines for operating and maintaining an eligible vehicle or machine;

(b) subject to subsection (1.2), an expenditure on a grant or zero-interest loan for an eligible vehicle or machine does not, in any year of the undertaking, exceed the percentage difference as indicated in the following table:

	Year of Undertaking										
	1	2	3	4	5	6	7	8	9	10	11
Percentage of the difference between the cost of the eligible vehicle or machine and the cost of a comparable vehicle that uses gasoline or diesel	100	80	70	60	50	40	30	25	20	10	0

(c) total expenditures on the undertaking during the undertaking period, including expenditures on administration, marketing, training and education, do not exceed $177.9 million less the total expenditures, if any, on an undertaking described in subsection (3.1), and

(i) Repealed. [B.C. Reg. 98/2015, s. 2 (e).]

(ii) expenditures on the undertaking during the undertaking period

(A) Repealed. [B.C. Reg. 214/2016, s. 3 (e).]

(B) on grants referred to in paragraph (a) (ii) do not exceed $6 million.

(1.1) Despite the reference in subsection (1) (a) to an open and competitive application process, a public utility may, in carrying out the undertaking described in subsection (1), give priority to a person in British Columbia who fuels an eligible vehicle or machine using natural gas delivered through the public utility's pipeline system.

(1.2) The percentage difference indicated in the table in subsection (1) (b) may be increased

(a) by up to 50 for each of years 5 through 11 of the undertaking period if the eligible vehicle or machine is an early adopter vehicle or machine, and

(b) by up to 20 for each of years 5 through 11 of the undertaking period if the vehicle is a specified vehicle, is not an early adopter vehicle or machine or a vehicle referred to in subsection (3.1) (a) and is owned or operated by a person who agrees, as a condition of receiving a grant or zero-interest loan, to

(i) complete or arrange for the completion of, within 3 years of the agreement, the construction of a compressed natural gas or liquefied natural gas fuelling station that

(A) is within 25 km of a major transportation corridor, and

(B) provides fuelling services to one or more other persons, or

(ii) operate or arrange for the operation of a fuelling station described in clauses (A) and (B).

(1.3) Despite subsections (1) (a) (i) and (1.1), grants or loans referred to in subsection (1) in relation to an early adopter vehicle or machine respecting the market segment described in the table in paragraph (b) of the definition of "earlier adopter vehicle or machine" as "Shipping, passenger transportation or commercial services by marine vehicle that will use fuel purchased from a public utility" may be made to persons who are not in British Columbia.

(1.4) Despite subsection (1) (c), the total expenditures referred to in that subsection may exceed $177.9 million by $40 million if the $40 million is for expenditures in relation to eligible vehicles or machines operated on liquefied natural gas or compressed natural gas all of which is derived from biogas or biomass.

(2) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility, before March 31, 2022, enters into a binding commitment to

(i) construct and operate, or

(ii) purchase and operate

one or more compressed natural gas fuelling stations, including storage, compression and dispensing equipment and facilities, within the service territory of the public utility for the purposes of providing compressed natural gas fuel and fuelling services to owners of vehicles that operate on compressed natural gas;

(b) total expenditures on the undertaking during the undertaking period, including expenditures on administration and marketing, do not exceed $12 million, and

(i) the average expenditure on stations, in any year of the undertaking, does not exceed $2 million per station, and

(ii) expenditures, during the undertaking period, on administration and marketing do not exceed $240 000;

(c) at least

(i) 80% of the station's forecast total operating costs for the first 5 years of the operation are recovered from one or more persons under a take-or-pay agreement with a minimum term of 5 years, or

(ii) 60% of the station's forecast total operating costs for the first 7 years of the operation are recovered from one or more persons under a take-or-pay agreement with a minimum term of 7 years.

(3) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility, before March 31, 2022, enters into a binding commitment to construct and operate, or purchase and operate, one or more of the following:

(i) one or more liquefied natural gas tank trailers or liquefied natural gas fuelling stations for the purposes of providing within British Columbia liquefied natural gas fuel and fuelling services to owners of vehicles that operate on liquefied natural gas;

(ii) one or more tanker truck load-outs for the purposes of providing within British Columbia liquefied natural gas fuel and fuelling services to owners of vehicles that operate on liquefied natural gas or to owners or operators of marine vehicles that operate on liquefied natural gas;

(b) total expenditures on the undertaking during the undertaking period, including expenditures on administration and marketing, do not exceed $50.5 million, and

(i) in any year of the undertaking period an expenditure on a station does not exceed $2.75 million, and

(ii) expenditures during the undertaking period on a tanker truck load-out do not exceed $10 million, and on administration and marketing do not exceed $250 000;

(c) at least

(i) 80% of the station's forecast total operating costs for the first 5 years of the operation are recovered from one or more persons under a take-or-pay agreement with a minimum term of 5 years, or

(ii) 60% of the station's forecast total operating costs for the first 7 years of the operation are recovered from one or more persons under a take-or-pay agreement with a minimum term of 7 years.

(3.1) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility provides, through an open and competitive application process, grants or zero-interest loans to owners or operators in British Columbia of specified vehicles for the conversion of those vehicles to operate on compressed natural gas or liquefied natural gas;

(b) total expenditures on the undertaking during the undertaking period, including expenditures on administration, marketing, training and education,

(i) do not exceed the lesser of the following amounts:

(A) the amount required for the conversion of 50 vehicles;

(B) $5 million, and

(ii) expenditures on the undertaking during the undertaking period on administration, marketing, training and education do not exceed $1.5 million.

(3.2) Subject to subsection (3.3), a public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility provides, through an open and competitive application process, grants or zero-interest loans to persons in British Columbia for

(i) the purchase or lease of generators, boilers, burners or kilns that use, as a fuel source, compressed natural gas or liquefied natural gas, or

(ii) the conversion of generators, boilers, burners or kilns to use, as a fuel source, compressed natural gas or liquefied natural gas

if the generators, boilers, burners or kilns will be operated at a location that, at the time of the expenditure, is not

(iii) within the authority's integrated area, or

(iv) connected to a natural gas transmission or distribution system;

(b) the total expenditures on the undertaking during the undertaking period, other than expenditures on administration, marketing, training and education, do not exceed $6.1 million.

(3.3) The undertakings referred to in subsections (1) and (3.2) are prescribed undertakings for the purposes of section 18 of the Act only if the total combined expenditures on the two undertakings, during the undertaking period on administration, marketing, training and education, do not exceed $8.1 million.

(3.4) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) the public utility, before March 31, 2022, enters into a binding commitment to

(i) construct and operate, or

(ii) purchase and operate

LNG distribution and storage infrastructure, other than liquefied natural gas fuelling stations, in British Columbia, including LNG rail tank cars, ISO containers and shore-side assets, for the purpose of reducing greenhouse gas emissions;

(b) total expenditures on the undertaking during the undertaking period, including expenditures on administration, marketing, training and education, do not exceed $40 million, and

(c) at least

(i) 80% of the forecast total operating costs of the distribution and storage infrastructure for the first 5 years of the operation are recovered from one or more persons under a take-or-pay agreement with a minimum term of 5 years, or

(ii) 60% of the forecast total operating costs of the distribution and storage infrastructure for the first 7 years of the operation are recovered from one or more persons under a take-or-pay agreement with a minimum term of 7 years.

(3.5) A public utility's undertaking that is in the class defined in subsection (3.6) is a prescribed undertaking for the purposes of section 18 of the Act.

(3.6) The public utility, during the undertaking period, expends amounts on feasibility and development costs in relation to shore-side assets that do not exceed $5 million.

(3.7) A public utility's undertaking that is in the class defined in subsection (3.8) is a prescribed undertaking for the purposes of section 18 of the Act.

(3.8) The public utility acquires renewable natural gas

(a) for which the public utility pays no more than $30 per GJ, and

(b) that, subject to subsection (3.9), in a calendar year, does not exceed 5% of the total volume of natural gas provided by the public utility to its non-bypass customers in 2015.

(3.9) The volume referred to in subsection (3.8) (b) does not include renewable natural gas acquired by the public utility that the public utility provides to a customer in accordance with a rate under which the full cost of the following is recovered from the customer:

(a) the acquisition of the renewable natural gas;

(b) the service related to the provision of the renewable natural gas.

(4) In subsections (1), (2), (3), (3.1), (3.2) and (3.4), **"expenditures"** includes, except with respect to expenditures on administration and marketing, binding

commitments to incur expenditures in the future.

[am. B.C. Regs. 235/2013, s. 2; 98/2015, s. 2; 214/2016, ss. 2 to 8; 114/2017, ss. 2 to 8.]

Repealed

3 Repealed. [B.C. Reg. 235/2013, s. 3.]

Prescribed undertaking — electrification

4 (1) In this section:

"benefit", in relation to an undertaking in a class defined in subsection (3) (a) or (b), means all revenues the public utility reasonably expects to earn as a result of implementing the undertaking, less revenues that would have been earned from the supply of undertaking electricity to export markets;

"cost", in relation to an undertaking in a class defined in subsection (3) (a) or (b), means costs the public utility reasonably expects to incur to implement the undertaking, including, without limitation, development and administration costs;

"cost-effective" means that the present value of the benefits of all of the public utility's undertakings within the classes defined in subsection (3) (a) or (b) exceeds the present value of the costs of all of those undertakings when both are calculated using a discount rate equal to the public utility's weighted average cost of capital over a period that ends no later than a specified year;

"natural gas processing plant" means a facility for processing natural gas by removing from it natural gas liquids, sulphur or other substances;

"specified year", in relation to an undertaking within a class defined in subsection (3), means

(a) a year determined by the minister with respect to an identified public utility, or

(b) if the minister does not make a determination for the purposes of paragraph (a), 2030;

"undertaking electricity" means electricity that is provided to customers in British Columbia as a result of an undertaking and is in addition to electricity that would have been provided had the undertaking not been carried out.

(2) A public utility's undertaking that is in a class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:

(a) for the purpose of reducing greenhouse gas emissions in British Columbia, the public utility constructs or operates an electricity transmission or distribution facility, or provides for temporary generation until the completion of the construction of the facility, in northeast British Columbia primarily to provide electricity from the authority to

(i) a producer, as defined in section 1 (1) of the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation, B.C. Reg. 495/92, or

(ii) an owner or operator of a natural gas processing plant;

(b) the public utility reasonably expects, on the date the public utility decides to carry out the undertaking, that the facility will have an in-service date no later than December 31, 2022.

(3) Subject to subsection (4), a public utility's undertaking that is in a class defined in one of the following paragraphs is a prescribed undertaking for the purposes of section 18 of the Act:

(a) a program to encourage the public utility's customers, or persons who may become customers of the public utility, to use electricity, instead of other sources of energy that produce more greenhouse gas emissions, by

(i) educating or training those customers respecting energy use and greenhouse gas emissions, carrying out public awareness campaigns respecting those matters, or providing energy management and audit services, or

(ii) providing funds to those persons to assist in the acquisition, installation or use of equipment that uses or affects the use of electricity;

(b) a program to encourage the public utility's customers, or persons who may become customers of the public utility, to use electricity instead of other sources of energy that produce more greenhouse gas emissions, by

(i) educating, training, providing energy management and audit services to, or carrying out awareness campaigns respecting energy use and greenhouse gas emissions for, or

(ii) providing funds to

persons who

(iii) design, manufacture, sell, install or, in the course of operating a business, provide advice respecting equipment that uses or affects the use of electricity,

(iv) design, construct, manage or, in the course of operating a business, provide advice respecting energy systems in buildings or facilities, or

(v) design, construct or manage district energy systems;

(c) a project, program, contract or expenditure for research and development of technology, or for conducting a pilot project respecting technology, that may enable the public utility's customers to use electricity instead of other sources of energy that produce more greenhouse gas emissions;

(d) a project, program, contract or expenditure supporting a standards-making body in its development of standards respecting

(i) technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions, or

(ii) technologies that affect the use of electricity by other technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions;

(e) a project for the construction, acquisition or extension of a plant or system, that the public utility reasonably expects is necessary to meet the public utility's incremental load-serving obligations arising as a result of an undertaking defined in paragraph (a), (b), (c) or (d), if the public utility reasonably expects any one such project to cost no more than $20 million.

(4) An undertaking is within a class of undertakings defined in paragraph (a) or (b) of subsection (3) only if, at the time the public utility decides to carry out the undertaking, the public utility reasonably expects the undertaking to be cost-effective.

[en. B.C. Reg. 76/2017.]

[Provisions relevant to the enactment of this regulation: *Clean Energy Act*, S.B.C. 2010, c. 22, section 35]

B.C. Reg. 77/2017 Deposited March 2, 2017
O.C. 100/2017

This consolidation is current to February 12, 2019.

Utilities Commission Act

DIRECTION TO THE BRITISH COLUMBIA UTILITIES COMMISSION RESPECTING UNDERTAKING COSTS

Definitions

1 In this direction:

"Act" means the *Utilities Commission Act*;

"DSM regulatory account" means the regulatory account of the authority established under commission order G-55-95;

"undertaking costs" means all costs incurred by the authority to implement an undertaking within a class defined in section 4 (3) (a), (b), (c) or (d) of the Greenhouse Gas Reduction (Clean Energy) Regulation.

Application

2 This direction is issued to the commission under section 3 of the Act.

Undertaking costs

3 The commission must allow the authority to defer to the DSM regulatory account amounts equal to the undertaking costs.

[Provisions relevant to the enactment of this regulation: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, section 3]

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 404 *, Approved and Ordered* July 14, 2015

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the attached Direction to the British Columbia Utilities Commission Respecting the Authority's TMP Program is made.

DEPOSITED

July 15, 2015

B.C. REG. **139/2015**

Minister of Energy and Mines and Minister Responsible for Core Review

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s. 3

Other:

May 19, 2015 R/182/2015/27

page 1 of 2

DIRECTION TO THE BRITISH COLUMBIA UTILITIES COMMISSION RESPECTING THE AUTHORITY'S TMP PROGRAM

Definitions

1 In this direction,

"Act" means the *Utilities Commission Act*;

"DSM regulatory account" means the regulatory account of the authority established under commission order G-55-95;

"TMP program" means the authority's program to provide funding to increase the electrical energy efficiency of mills that use thermo-mechanical pulping processes.

Application

2 This direction is issued to the commission under section 3 of the Act.

TMP program

3 (1) Subject to subsection (2), in setting rates for the authority, the commission must not disallow for any reason the recovery in rates of the costs incurred by the authority in carrying out the TMP program.

(2) The costs recovered by rates referred to in subsection (1) must not exceed $100 million.

(3) The commission must, in regard to the DSM regulatory account, allow the authority to defer to that account the authority's costs incurred as a result of carrying out the TMP program.

B.C. Reg. 326/2008
M271/2008

Deposited November 7, 2008

This consolidation is current to September 18, 2018.

Link to Point in Time

Utilities Commission Act

DEMAND-SIDE MEASURES REGULATION

[includes amendments up to B.C. Reg. 117/2017, March 24, 2017]

Contents

Definitions

1 In this regulation:

"Act" means the *Utilities Commission Act*;

"bulk electricity purchaser" means a public utility that purchases electricity from the authority for resale to the public utility's customers;

"charity program" means a program to reduce energy consumption in buildings

(a) owned and used by a charity that provides assistance to low-income persons, or

(b) leased by a charity that provides assistance to low-income persons, if the benefits of the program accrue primarily to the charity;

"clean or renewable resource" has the same meaning as in the *Clean Energy Act*;

"community engagement program" means a program delivered by

(a) a public utility to a public entity either

(i) to increase the public entity's awareness about ways to increase energy conservation and energy efficiency or to encourage the public entity to conserve energy or use energy efficiently, or

(ii) to assist the public entity to increase the public's awareness about ways to increase energy conservation and energy efficiency or to encourage the public to conserve energy or use energy efficiently, or

(b) a public utility in cooperation with a public entity to increase the public's awareness about ways to increase energy conservation and energy efficiency or to encourage the public to conserve energy or use energy efficiently;

"education program" means an education program about energy conservation and efficiency, and includes the funding of the development of such a program;

"energy efficiency training" means training for persons who

(a) manufacture, sell or install energy-efficient products or products that conserve energy,

(b) design, construct or act as a real estate broker with respect to energy-efficient buildings,

(c) manage energy systems,

(d) conduct energy efficiency and conservation audits,

(e) on behalf of an organization, manage or advise with respect to the conservation or efficient use of energy in the organization's facilities, or

(f) in an organization, educate other persons about the benefits of energy efficiency and conservation;

"energy management program" means a program to assist customers to optimize energy use;

"energy-using product" has the same meaning as in the *Energy Efficiency Act* (Canada);

"expenditure portfolio" means the class of demand-side measures that is composed of all of the demand-side measures proposed by a public utility in an expenditure schedule submitted under section 44.2 of the Act;

"low-income household" means a household whose residents receive service from the public utility and

(a) the residents have, in a taxation year, a before-tax annual household income equal to or less than the low-income cut-off established by Statistics Canada for that year for households of that size, multiplied by 1.3, or

(b) the account holder receives one or more of the following:

(i) guaranteed income supplement under the *Old Age Security Act* (Canada);

(ii) allowance under the *Old Age Security Act* (Canada) for persons aged 60 to 64 with spouses or common-law partners who receive a pension under that Act and are eligible for a guaranteed income supplement;

(iii) survivor's allowance under the *Old Age Security Act* (Canada);

(iv) disability benefits under the *Canada Pension Plan* (Canada);

(v) National Child Benefit Supplement;

(vi) shelter aid for elderly renters under the *Shelter Aid for Elderly Renters Act*;

(vii) income assistance for persons with persistent multiple barriers to employment under the *Employment and Assistance Act*;

(viii) Provincial senior's supplement under the *Employment and Assistance Act*;

(ix) income assistance under the *Employment and Assistance Act*;

(x) hardship assistance under the *Employment and Assistance Act*;

(xi) disability assistance under the *Employment and Assistance for Persons with Disabilities Act*;

(xii) rental assistance provided by the British Columbia Housing Management Commission;

"plan portfolio" means the class of demand-side measures that is composed of all of the demand-side measures proposed by a public utility in a plan submitted under section 44.1 of the Act;

"public awareness program" means a program delivered by a public utility

(a) to increase the awareness of the public, including the public utility's customers, about ways to increase energy conservation and energy efficiency or to encourage the public, including the public utility's customers, to conserve energy or use energy efficiently, or

(b) to increase participation by the public utility's customers in other demand-side measures proposed by the public utility in an expenditure portfolio or a plan portfolio

but does not include a program to increase the amount of energy sold or delivered by the public utility;

"public entity" means

(a) a local government,

(b) a first nation,

(c) a society incorporated under the *Societies Act*, other than a member-funded society as defined in section 190 of that Act, or

(d) a trade union;

"regulated item" means

(a) a product or system that uses energy or controls or affects the use of energy,

(b) an energy-using product,

(c) a building design,

(d) Repealed. [B.C. Reg. 228/2011, s. 1 (d).]

(e) a building site design or building site selection plan, or

(f) a community design;

"school" means a school regulated under the *School Act* or the *Independent School Act*;

"specified demand-side measure" means

(a) a demand-side measure referred to in section 3 (c) or (d),

(b) the funding of energy efficiency training,

(c) a community engagement program,

(c.1) an energy management program,

(d) a technology innovation program, or

(e) financial or other resources provided

(i) to a standards-making body to support the development of standards respecting energy conservation or the efficient use of energy, or

(ii) to a government or regulatory body to support the development of or compliance with a specified standard or a measure respecting energy conservation or the efficient use of energy in the Province;

"specified proposal" means

(a) a proposal respecting an amendment to the regulation referred to in paragraph (a) of the definition of "specified standard", if the proposal is published by the government;

(b) a proposal respecting an amendment to the regulations referred to in paragraph (b) of the definition of "specified standard", if the proposed amendment is published in the Canada Gazette;

(c) a proposal respecting an amendment to the regulation referred to in paragraph (c) of the definition of "specified standard", if the proposal is published by the government;

(d) a proposal respecting

(i) a new bylaw, or

(ii) an amendment to a bylaw

referred to in paragraph (d) of the definition of "specified standard", if the proposal has been given first reading by the council of the local authority;

(e) a proposal respecting

(i) a new law, or

(ii) an amendment to a law

referred to in paragraph (e) of the definition of "specified standard", if the proposal has been published by the governing body referred to in that paragraph;

"specified standard" means a standard in any of the following:

(a) the Energy Efficiency Standards Regulation, B.C. Reg. 389/93;

(b) the Energy Efficiency Regulations SOR/94-651;

(c) the British Columbia Building Code, if the standard promotes energy conservation or the efficient use of energy;

(d) a bylaw of a local authority, if the standard promotes energy conservation or the efficient use of energy in the Province;

(e) a law passed by a governing body of a first nation, if the standard promotes energy conservation or the efficient use of energy in the Province;

"step code", in relation to a building to which Part 3 or 9 of the British Columbia Building Code (the Code) applies, means energy efficiency requirements in a regulation made under section 3 of the *Building Act* that are more stringent than the requirements in

(a) Sentence 10.2.1.1. (1) of the Code, for buildings to which Part 3 of the Code applies, or

(b) Subsections 9.36.2. to 9.36.4. of the Code, for buildings to which Part 9 of the Code applies;

"technology innovation program" means a program

(a) to develop, use or support the increased use of a technology, a system of technologies, a building design or an industrial facility design that is

(i) not commonly used in British Columbia, and

(ii) the use of which could directly or indirectly result in significant reductions of energy use or significantly more efficient use of energy,

(b) to do what is described in paragraph (a) and to give demonstrations to the public of any results of doing what is described in paragraph (a), or

(c) to gather information about a technology, a system of technologies, a building design or an industrial design referred to in paragraph (a).

[am. B.C. Regs. 228/2011, s. 1; 141/2014, s. 1; 117/2017, Sch., s. 1.]

Application

2 (1) Repealed. [B.C. Reg. 326/2008, s. 2 (2).]

(2) Effective June 1, 2009,

(a) subsection (1) is repealed, and

(b) section 3 does not apply to a public utility that is owned or operated by a local government or has fewer than 10 000 customers.

Adequacy

3 (1) A public utility's plan portfolio is adequate for the purposes of section 44.1 (8) (c) of the Act only if the plan portfolio includes all of the following:

(a) a demand-side measure intended specifically

(i) to assist residents of low-income households to reduce their energy consumption, or

(ii) to reduce energy consumption in housing owned or operated by

(A) a housing provider that is a local government, a society as defined in section 1 of the *Societies Act*, other than a member-funded society as defined in section 190 of that Act, or an association as defined in section 1 (1) of the *Cooperative Association Act*, or

(B) the governing body of a first nation, if the benefits of the reduction primarily accrue to

(C) the low-income households occupying the housing,

(D) a housing provider referred to in clause (A), or

(E) a governing body referred to in clause (B) if the households in the governing body's housing are primarily low-income households;

(b) if the plan portfolio is submitted on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;

(c) an education program for students enrolled in schools in the public utility's service area;

(d) if the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area;

(e) one or more demand-side measures to provide resources as set out in paragraph (e) of the definition of "specified demand-side measure", representing no less than

(i) an average of 1% of the public utility's plan portfolio's expenditures per year over the portfolio's period of expenditures, or

(ii) an average of $2 million per year over the portfolio's period of expenditures;

(f) one or more demand-side measures intended to result in the adoption by local governments and first nations of a step code or more stringent requirements within a step code.

(2) The commission, when considering whether a plan portfolio is adequate under subsection (1), may consider a demand-side measure that is not included in the plan portfolio to be a part of the plan portfolio.

[am. B.C. Reg. 141/2014, s. 2; 117/2017, Sch., s. 2.]

Cost effectiveness

4 (1) Subject to subsections (1.5), (4) and (5), the commission, in determining for the purposes of section 44.1 (8) (c) or 44.2 (5) (d) of the Act the cost-effectiveness of a demand-side measure proposed in an expenditure portfolio or a plan portfolio, may compare the costs and benefits of

(a) the demand-side measure individually,

(b) the demand-side measure and other demand-side measures in the portfolio, or

(c) the portfolio as a whole.

(1.1) Subject to subsection (2), the commission must make determinations of cost effectiveness by applying the total resource cost test as follows and in the order set out:

(a) subject to subsections (1.2) and (1.3), the avoided natural gas cost, if any, respecting a demand-side measure, in addition to the avoided capacity cost, is the amount that the commission is satisfied represents the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia;

(b) subject to subsection (1.3), the avoided electricity cost, if any, respecting a demand-side measure, in addition to the avoided capacity cost, is

(i) in the case of a demand-side measure of FortisBC Inc., an amount that the commission is satisfied represents FortisBC Inc.'s long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia, and

(ii) in the case of a demand-side measure not referred to in subparagraph (i), an amount that the commission is satisfied represents the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia;

(c) with respect to a demand-side measure that is not referred to in section 3 (1) (a) and that is not a charity program, do the following:

(i) increase the benefits of the demand-side measure by an amount that does not exceed an amount proposed by the public utility for this purpose, if the commission is satisfied that the amount represents the participant or utility non-energy benefits of the demand-side measure;

(ii) if the benefits of a demand-side measure have not been increased under subparagraph (i) or if the benefits of the expenditure portfolio of which the demand-side measure is a part has not been increased by 15% or more as a result of an increase under subparagraph (i), increase the benefit of the demand-side measure by an amount that

(A) increases by 15% the benefits of the expenditure portfolio of which the demand-side measure is a part, and

(B) is equal to the increase made under this subparagraph for all the other demand-side measures that are part of the expenditure portfolio;

(d) the benefit of the demand-side measure is what it would have been had no step code been adopted in the Province.

(1.2) Subsection (1.1) (a) does not apply to a demand-side measure that reduces the use of natural gas but does not reduce greenhouse gas emissions associated with that use of natural gas.

(1.3) Subsection (1.1) (a) and (b) does not apply to a demand-side measure that encourages a switch from the use of oil or propane to the use of natural gas or electricity such that the switch would decrease greenhouse gas emissions in British Columbia.

(1.4) In considering a demand-side measure that, in the commission's opinion, will increase the use of a regulated item with respect to which there is either

(a) a specified standard that has not yet commenced, or

(b) a specified proposal,

the commission, after applying subsection (1.1), may increase the benefit of the demand-side measure by an amount that represents a portion of the avoided capacity and energy costs that, in the commission's opinion, will result from the commencement and application of the specified standard, amendment or new bylaw proposed by the specified proposal, assuming that the standard, amendment or new bylaw comes into force.

(1.5) Despite subsection (1.1) and subject to subsections (1.9), (4) and (5), the commission must determine that a demand-side measure, other than a demand-side measure referred to in section 3 (1) (a) or a charity program, that is part of an expenditure portfolio and that is cost effective when applying subsection (1.1) is not cost effective if

(a) the demand-side measure is not cost-effective without applying subsection (1.1), and

(b) the total expenditures respecting

(i) the demand-side measure, and

(ii) all other demand-side measures that are part of the expenditure portfolio, that are not cost effective without applying subsection (1.1) and that are cost effective when applying subsection (1.1),

are more than

(iii) 40% of the total expenditures for the expenditure portfolio, in the case of a utility that recovers the expenditures in gas rates, or

(iv) 10% of the total expenditures for the expenditure portfolio, in the case of a utility that recovers the expenditures in electricity rates.

(1.6) For greater certainty, if the commission determines under subsection (1.5) that a demand-side measure that is part of an expenditure portfolio is not cost effective, the commission must exclude that demand-side measure from consideration when determining under that subsection whether another demand-side measure that is part of the expenditure portfolio is cost effective.

(1.7) For the purposes of subsections (1.1) (c) and (1.5), the commission, when considering the benefits or expenditures respecting a public utility's expenditure portfolio, may consider a demand-side measure of the public utility that is not included in the expenditure portfolio to be a part of the expenditure portfolio.

(1.8) Despite subsection (1.1), the commission may determine that a demand-side measure, other than

(a) a specified demand-side measure,

(a.1) a charity program,

(b) a public awareness program,

(c) a demand-side measure referred to in section 3 (1) (a), or

(d) a demand-side measure that is cost effective without applying subsection (1.1) but after applying subsection (1.4)

is not cost effective if the demand-side measure would not be considered cost-effective under the utility cost test.

(1.9) The references in subsections (1.5) and (1.8) to subsection (1.1) must be read as references

(a) to subsection (1.1) (a), (b) and (c) for the purposes of a demand-side measure that is part of an expenditure portfolio for any period before January 1, 2015, and

(b) to subsection (1.1) (a) and (c) for the purposes of a demand-side measure that is part of an expenditure portfolio for any period after December 31, 2014.

(2) In determining whether a demand-side measure referred to in section 3 (1) (a) or a charity program is cost effective, the commission must,

(a) in addition to conducting any other analysis the commission considers appropriate, use the total resource cost test, and

(b) in using the total resource cost test, make the adjustments referred to in subsection (1.1) (a) and (b) and then increase the value of the benefit of the demand-side measure by 40%.

(3) Repealed. [B.C. Reg. 228/2011, s. 2 (d).]

(4) The commission must determine the cost-effectiveness of a specified demand-side measure proposed in a plan portfolio or an expenditure portfolio by determining whether the portfolio is cost effective as a whole.

(5) If the commission is satisfied that a public awareness program proposed in a plan portfolio or an expenditure portfolio is likely to accomplish the goals set out in paragraph (a) or (b) of the definition of "public awareness program", the commission must determine the cost-effectiveness of the program by determining whether the portfolio is cost-effective as a whole.

(6) The commission may not determine that a proposed demand-side measure is not cost effective on the basis of the result obtained by using a ratepayer impact measure test to assess the demand-side measure.

(7) Repealed. [B.C. Reg. 228/2011, s. 2 (d).]

[am. B.C. Regs. 228/2011, s. 2; 141/2014, s. 3; 117/2017, Sch., s. 3.]

[Provisions relevant to the enactment of this regulation: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, section 125.1]

Volume 51, No. 22 B.C. Reg. 326/2008	The British Columbia Gazette, Part II November 18, 2008

B.C. Reg. 326/2008, deposited November 7, 2008, pursuant to the **UTILITIES COMMISSION ACT** [Section 125.1 (4) (e)]. Ministerial Order M271/2008, dated November 6, 2008.

I, Richard Neufeld, Minister of Energy, Mines and Petroleum Resources, order that the attached regulation is made.

— R. NEUFELD, *Minister of Energy, Mines and Petroleum Resources.*

DEMAND-SIDE MEASURES REGULATION

Definitions

1 In this regulation:

"Act" means the *Utilities Commission Act*;

"bulk electricity purchaser" means a public utility that purchases electricity from the authority for resale to the public utility's customers;

"community engagement program" means a program delivered by

(a) a public utility to a public entity either

(i) to increase the public entity's awareness about ways to increase energy conservation and energy efficiency or to encourage the public entity to conserve energy or use energy efficiently, or

(ii) to assist the public entity to increase the public's awareness about ways to increase energy conservation and energy efficiency or to encourage the public to conserve energy or use energy efficiently, or

(b) a public utility in cooperation with a public entity to increase the public's awareness about ways to increase energy conservation and energy efficiency or to encourage the public to conserve energy or use energy efficiently;

"education program" means an education program about energy conservation and efficiency, and includes the funding of the development of such a program;

"energy device" has the same meaning as in the *Energy Efficiency Act*;

"energy efficiency training" means training for persons who

(a) manufacture, sell or install energy-efficient products,

(b) design, construct or act as a real estate broker with respect to energy-efficient buildings,

(c) manage energy systems in buildings, or

(d) conduct energy efficiency audits;

"energy-using product" has the same meaning as in the *Energy Efficiency Act* (Canada);

"expenditure portfolio" means the class of demand-side measures that is composed of all of the demand-side measures proposed by a public utility in an expenditure schedule submitted under section 44.2 of the Act;

"low-income household" means a household whose residents receive service from the public utility and who have, in a taxation year, a before-tax annual household income equal to or less than the low-income cut off established by Statistics Canada for that year for households of that type;

"plan portfolio" means the class of demand-side measures that is composed of all of the demand-side measures proposed by a public utility in a plan submitted under section 44.1 of the Act;

"public awareness program" means a program delivered by a public utility

(a) to increase the awareness of the public, including the public utility's customers, about ways to increase energy conservation and energy efficiency or to encourage the public, including the public utility's customers, to conserve energy or use energy efficiently, or

(b) to increase participation by the public utility's customers in other demand-side measures proposed by the public utility in an expenditure portfolio or a plan portfolio

but does not include a program to increase the amount of energy sold or delivered by the public utility;

"public entity" means a local government, first nation, non-profit society incorporated under the *Society Act* or trade union;

"regulated item" means

(a) an energy device,

(b) an energy-using product,

(c) a building design, or

(d) thermal insulation;

"school" means a school regulated under the *School Act* or the *Independent School Act*;

"specified demand-side measure" means

(a) a demand-side measure referred to in section 3 (c) or (d),

(b) the funding of energy efficiency training,

(c) a community engagement program, or

(d) a technology innovation program;

"specified standard" means a standard in any of the following:

(a) the Energy Efficiency Standards Regulation, B.C. Reg. 389/93;

(b) the Energy Efficiency Regulations S.O.R./94-651;

(c) the British Columbia Building Code, if the standard promotes energy conservation or the efficient use of energy;

"technology innovation program" means a program

(a) to develop a technology, a system of technologies, a building design or an industrial facility design that is

(i) not commonly used in British Columbia, and

(ii) the use of which could directly or indirectly result in significant reductions of energy use or significantly more efficient use of energy,

(b) to do what is described in paragraph (a) and to give demonstrations to the public of any results of doing what is described in paragraph (a), or

(c) to gather information about a technology, a system of technologies, a building design or an industrial design referred to in paragraph (a).

Application

2 (1) This regulation applies only with respect to demand-side measures proposed by the authority.

(2) Effective June 1, 2009,

(a) subsection (1) is repealed, and

(b) section 3 does not apply to a public utility that is owned or operated by a local government or has fewer than 10,000 customers.

Adequacy

3 A public utility's plan portfolio is adequate for the purposes of section 44.1 (8) (c) of the Act only if the plan portfolio includes all of the following:

(a) a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;

(b) if the plan portfolio is submitted on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;

(c) an education program for students enrolled in schools in the public utility's service area;

(d) if the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area.

Cost effectiveness

4 (1) Subject to subsections (4) and (5), the commission, in determining for the purposes of section 44.1 (8) (c) or 44.2 (5) (d) of the Act the cost-effectiveness of a demand-side measure proposed in an expenditure portfolio or a plan portfolio, May compare the costs and benefits of

(a) the demand-side measure individually,

(b) the demand-side measure and other demand-side measures in the portfolio, or

(c) the portfolio as a whole.

(2) In determining whether a demand-side measure referred to in section 3 (a) is cost effective, the commission must,

(a) in addition to conducting any other analysis the commission considers appropriate, use the total resource cost test, and

(b) in using the total resource cost test, consider the benefit of the demand-side measure to be 130% of its value when determined without reference to this subsection.

(3) In determining whether a demand-side measure of a bulk electricity purchaser is cost-effective, the commission must consider the benefit of the avoided supply cost to be the authority's long-term marginal cost of acquiring new electricity to replace the electricity sold to the bulk electricity purchaser and not the bulk electricity purchaser's cost of purchasing electricity from the authority.

(4) The commission must determine the cost-effectiveness of a specified demand-side measure proposed in a plan portfolio or an expenditure portfolio by determining whether the portfolio is cost effective as a whole.

(5) If the commission is satisfied that a public awareness program proposed in a plan portfolio or an expenditure portfolio is likely to accomplish the goals set out in paragraph (a) or (b) of the definition of "public awareness program", the commission must determine the cost-effectiveness of the program by determining whether the portfolio is cost-effective as a whole.

(6) The commission May not determine that a proposed demand-side measure is not cost effective on the basis of the result obtained by using a ratepayer impact measure test to assess the demand-side measure.

(7) In considering the benefit of a demand-side measure that, in the commission's opinion, will increase the market share of a regulated item with respect to which there is a specified standard that has not yet commenced, the commission May include in the benefit a proportion of the benefit that, in the

commission's opinion, will result from the commencement and application of the specified standard with respect to the regulated item.

Volume 54, No. 23 228/2011	The British Columbia Gazette, Part II December 13, 2011

B.C. Reg. 228/2011, deposited December 8, 2011, pursuant to the **UTILITIES COMMISSION ACT** [section 125.1 (4) (e)]. Ministerial Order M335/2011, dated December 8, 2011.

I, Rich Coleman, Minister of Energy and Mines and Minister Responsible for Housing, order that the Demand-Side Measures Regulation, B.C. Reg. 326/2008, is amended as set out in the attached schedule.

— R. COLEMAN, *Minister of Energy and Mines and Minister Responsible for Housing*.

Schedule

1 Section 1 of the Demand-Side Measures Regulation, B.C. Reg. 326/2008, is amended

(a) by adding the following definition:

"clean or renewable resource" has the same meaning as in the *Clean Energy Act*; ***,***

(b) by repealing the definition of* "energy device"*,

(c) by repealing the definition of* "energy efficiency training" *and substituting the following:

"energy efficiency training" means training for persons who

(a) manufacture, sell or install energy-efficient products or products that conserve energy,

(b) design, construct or act as a real estate broker with respect to energy-efficient buildings,

(c) manage energy systems,

(d) conduct energy efficiency and conservation audits,

(e) on behalf of an organization, manage or advise with respect to the conservation or efficient use of energy in the organization's facilities, or

(f) in an organization, educate other persons about the benefits of energy efficiency and conservation; ***,***

(d) by repealing paragraphs (a) and (d) in the definition of* "regulated item" *and substituting the following:

(a) a product or system that uses energy or controls or affects the use of energy,

(e) a building site design or building site selection plan, or

(f) a community design; **,**

(e) in the definition of* "specified demand-side measure" *by adding the following paragraph:

(e) financial or other resources provided

(i) to a standards-making body to support the development of standards respecting energy conservation or the efficient use of energy, or

(ii) to a government or regulatory body to support the development of or compliance with a specified standard or a measure respecting energy conservation or the efficient use of energy in the Province; **,**

(f) by adding the following definition:

"specified proposal" means

(a) a proposal respecting an amendment to the regulation referred to in paragraph (a) of the definition of "specified standard", if the proposal is published by the minister responsible for the *Energy Efficiency Act* and specifically refers to this regulation;

(b) a proposal respecting an amendment to the regulations referred to in paragraph (b) of the definition of "specified standard", if the proposed amendment is published in the Canada Gazette;

(c) a proposal respecting an amendment to a standard referred to in paragraph (c) of the definition of "specified standard", if the proposal is published by the government and specifically refers to this regulation;

(d) a proposal respecting

(i) a new bylaw, or

(ii) an amendment to a bylaw

referred to in paragraph (d) of the definition of "specified standard", if the proposal has been given first reading by the council of the local authority;

(e) a proposal respecting

(i) a new law, or

(ii) an amendment to a law

referred to in paragraph (e) of the definition of "specified standard", if the proposal has been published by the governing body referred to in that paragraph; **,**

(g) in the definition of* "specified standard" *by adding the following paragraphs:

(d) a bylaw of a local authority, if the standard promotes energy conservation or the efficient use of energy in the Province;

(e) a law passed by a governing body of a first nation, if the standard promotes energy conservation or the efficient use of energy in the Province; ***, and***

(h) in paragraph (a) of the definition of **"technology innovation program"** ***by adding "***, use or support the increased use of***" after "***to develop***".***

2 Section 4 is amended

(a) in subsection (1) by striking out "Subject to subsections (4) and (5)***" and substituting "***Subject to subsections (1.5), (4) and (5)***",***

(b) by adding the following subsections:

(1.1) The commission must make determinations of cost effectiveness by applying the total resource cost test as follows and in the order set out:

(a) subject to subsections (1.2) and (1.3), the avoided natural gas cost, if any, respecting a demand-side measure, in addition to the avoided capacity cost, is the amount that the commission is satisfied represents the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia, multiplied by 0.5;

(b) subject to subsection (1.3), the avoided electricity cost, if any, respecting a demand-side measure, in addition to the avoided capacity cost, is

(i) in the case of a demand-side measure of FortisBC Inc., an amount that the commission is satisfied represents FortisBC Inc.'s long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia, and

(ii) in the case of a demand-side measure not referred to in subparagraph (i), an amount that the commission is satisfied represents the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia;

(c) with respect to a demand-side measure not referred to in section 3 (a), do the following:

(i) increase the benefits of the demand-side measure by an amount that does not exceed an amount proposed by the public utility for this purpose, if the commission is satisfied that the amount represents the participant or utility non-energy benefits of the demand-side measure;

(ii) if the benefits of a demand-side measure have not been increased under subparagraph (i) or if the benefits of the expenditure portfolio of which the demand-side measure is a part has not been increased by 15% or more as a result of an increase under subparagraph (i), increase the benefit of the demand-side measure by an amount that

(A) increases by 15% the benefits of the expenditure portfolio of which the demand-side measure is a part, and

(B) is equal to the increase made under this subparagraph for all the other demand-side measures that are part of the expenditure portfolio.

(1.2) Subsection (1.1) (a) does not apply to a demand-side measure that reduces the use of natural gas but does not reduce greenhouse gas emissions associated with that use of natural gas.

(1.3) Subsection (1.1) (a) and (b) does not apply to a demand-side measure that encourages a switch from the use of oil or propane to the use of natural gas or electricity such that the switch would decrease greenhouse gas emissions in British Columbia.

(1.4) In considering a demand-side measure that, in the commission's opinion, will increase the use of a regulated item with respect to which there is either

(a) a specified standard that has not yet commenced, or

(b) a specified proposal,

the commission, after applying subsection (1.1), may increase the benefit of the demand-side measure by an amount that represents a portion of the avoided capacity and energy costs that, in the commission's opinion, will result from the commencement and application of the specified standard, amendment or new bylaw proposed by the specified proposal, assuming that the standard, amendment or new bylaw comes into force.

(1.5) Despite subsection (1.1) and subject to subsections (4) and (5), the commission must determine that a demand-side measure that is part of an expenditure portfolio and that is cost effective when applying subsection (1.1) is not cost effective if

(a) the demand-side measure is not cost-effective without applying subsection (1.1), and

(b) the total expenditures respecting

(i) the demand-side measure, and

(ii) all other demand-side measures that are part of the expenditure portfolio, that are not cost effective without applying subsection (1.1) and that are cost effective when applying subsection (1.1),

are more than

(iii) 33% of the total expenditures for the expenditure portfolio, in the case of a utility that recovers the expenditures in gas rates, or

(iv) 10% of the total expenditures for the expenditure portfolio, in the case of a utility that recovers the expenditures in electricity rates.

(1.6) For greater certainty, if the commission determines under subsection (1.5) that a demand-side measure that is part of an expenditure portfolio is not cost effective, the commission must exclude that demand-side measure from consideration when determining under that subsection whether another demand-side measure that is part of the expenditure portfolio is cost effective.

(1.7) For the purposes of subsections (1.1) (c) and (1.5), the commission, when considering the benefits or expenditures respecting a public utility's expenditure portfolio, may consider a demand-side measure of the public utility that is not included in the expenditure portfolio to be a part of the expenditure portfolio.

(1.8) Despite subsection (1.1), the commission may determine that a demand-side measure, other than

(a) a specified demand-side measure,

(b) a public awareness program,

(c) a demand-side measure referred to in section 3 (a), or

(d) a demand-side measure that is cost effective without applying subsection (1.1) but after applying subsection (1.4)

is not cost effective if the demand-side measure would not be considered cost-effective under the utility cost test.

(c) in subsection (2) (b) by adding "but after applying subsection (1.1)***" after "***without reference to this subsection***", and***

(d) by repealing subsections (3) and (7).

Volume 57, No. 13 141/2014	The British Columbia Gazette, Part II July 15, 2014

B.C. Reg. 141/2014, deposited July 10, 2014, under the **UTILITIES COMMISSION ACT** [section 125.1]. Ministerial Order M233/2014, dated June 4, 2014

I, Bill Bennett, Minister of Energy and Mines and Minister Responsible for Core Review, order that the Demand-Side Measures Regulation, B.C. Reg 326/2008, is amended as set out in the attached Schedule.

— W. R. BENNETT, *Minister of Energy and Mines and Minister Responsible for Core Review*.

SCHEDULE

1 Section 1 of the Demand-Side Measures Regulation, B.C. Reg. 326/2008, is amended by repealing the definition of* "low-income household" *and substituting the following:

"low-income household" means a household whose residents receive service from the public utility and

(a) the residents have, in a taxation year, a before-tax annual household income equal to or less than the low-income cut-off established by Statistics Canada for that year for households of that size, multiplied by 1.3, or

(b) the account holder receives one or more of the following:

(i) guaranteed income supplement under the *Old Age Security Act* (Canada);

(ii) allowance under the *Old Age Security Act* (Canada) for persons aged 60 to 64 with spouses or common-law partners who receive a pension under that Act and are eligible for a guaranteed income supplement;

(iii) survivor's allowance under the *Old Age Security Act* (Canada);

(iv) disability benefits under the *Canada Pension Plan* (Canada);

(v) National Child Benefit Supplement;

(vi) shelter aid for elderly renters under the *Shelter Aid for Elderly Renters Act*;

(vii) income assistance for persons with persistent multiple barriers to employment under the *Employment and Assistance Act*;

(viii) Provincial senior's supplement under the *Employment and Assistance Act*;

(ix) income assistance under the *Employment and Assistance Act*;

(x) hardship assistance under the *Employment and Assistance Act*;

(xi) disability assistance under the *Employment and Assistance for Persons with Disability Act*;

(xii) rental assistance provided by the British Columbia Housing Management Commission;

2 Section 3 (a) is repealed and the following is substituted:

(a) a demand-side measure intended specifically

(i) to assist residents of low-income households to reduce their energy consumption, or

(ii) to reduce energy consumption in housing owned or operated by

(A) a housing provider incorporated under the *Society Act* or the *Cooperative Association Act*, or

(B) a band within the meaning of the *Indian Act* (Canada),

if the benefits of the reduction primarily accrue to

(C) the low-income households occupying the housing,

(D) a housing provider referred to in clause (A), or

(E) a band referred to in clause (B) if the households in the band's housing are primarily low-income households;

3 Section 4 is amended

(a) in subsection (1.1) (a) by striking out ", multiplied by 0.5***",***

(b) in subsection (1.5) by striking out "subject to subsections (4) and (5),***" and substituting "***subject to subsections (1.9), (4) and (5),***",***

(c) by adding the following subsection:

(1.9) The references in subsections (1.5) and (1.8) to subsection (1.1) must be read as references

(a) to subsection (1.1) (a), (b) and (c) for the purposes of a demand-side measure that is part of an expenditure portfolio for any period before January 1, 2015, and

(b) to subsection (1.1) (a) and (c) for the purposes of a demand-side measure that is part of an expenditure portfolio for any period after December 31, 2014. ***, and***

(d) in subsection (2) (b) by striking out "130%***" and substituting "***140%***".***

Volume 60, No. 5 117/2017	The British Columbia Gazette, Part II March 28, 2017

B.C. Reg. 117/2017, deposited March 24, 2017, under the **UTILITIES COMMISSION ACT** [section 125.1]. Ministerial Order M138/2017, dated March 22, 2017.

I, Bill Bennett, Minister of Energy and Mines and Minister Responsible for Core Review, order that

(a) the Demand-Side Measures Regulation, B.C. Reg. 326/2008, is amended as set out in the attached Schedule, and

(b) the amendments made in accordance with paragraph (a) of this order do not apply with respect to the application for acceptance, under section 44.2 of the *Utilities Commission Act*, of the demand-side management expenditure schedule included in the revenue requirement application submitted by the authority to the commission on July 28, 2016.

— W. R. BENNETT, *Minister of Energy and Mines and Minister Responsible for Core Review*.

SCHEDULE

1 Section 1 of the Demand-Side Measures Regulation, B.C. Reg. 326/2008, is amended

(a) by adding the following definitions:

"charity program" means a program to reduce energy consumption in buildings

(a) owned and used by a charity that provides assistance to low-income persons, or

(b) leased by a charity that provides assistance to low-income persons, if the benefits of the program accrue primarily to the charity;

"energy management program" means a program to assist customers to optimize energy use; ***,***

(b) by repealing the definition of **"public entity"** ***and substituting the following:***

"public entity" means

(a) a local government,

(b) a first nation,

(c) a society incorporated under the *Societies Act*, other than a member-funded society as defined in section 190 of that Act, or

(d) a trade union; ***,***

(c) in the definition of **"specified demand-side measure"** ***by adding the following paragraph:***

(c.1) an energy management program, ***,***

(d) by repealing paragraphs (a) and (c) of the definition of **"specified proposal"** ***and substituting the following:***

(a) a proposal respecting an amendment to the regulation referred to in paragraph (a) of the definition of "specified standard", if the proposal is published by the government;

(c) a proposal respecting an amendment to the regulation referred to in paragraph (c) of the definition of "specified standard", if the proposal is published by the government; ***, and***

(e) by adding the following definition:

"step code", in relation to a building to which Part 3 or 9 of the British Columbia Building Code (the Code) applies, means energy efficiency requirements in a regulation made under section 3 of the *Building Act* that are more stringent than the requirements in

(a) Sentence 10.2.1.1. (1) of the Code, for buildings to which Part 3 of the Code applies, or

(b) Subsections 9.36.2. to 9.36.4. of the Code, for buildings to which Part 9 of the Code applies.

2 Section 3 is amended

(a) by renumbering the section as section 3 (1),

(b) by repealing subsection (1) (a) (ii) (A) and (B) and substituting the following:

(A) a housing provider that is a local government, a society as defined in section 1 of the *Societies Act*, other than a member-funded society as defined in section 190 of that Act, or an association as defined in section 1 (1) of the *Cooperative Association Act*, or

(B) the governing body of a first nation, ***,***

(c) by repealing subsection (1) (a) (ii) (E) and substituting the following:

(E) a governing body referred to in clause (B) if the households in the governing body's housing are primarily low-income households; ***,***

(d) in subsection (1) by adding the following paragraphs:

(e) one or more demand-side measures to provide resources as set out in paragraph (e) of the definition of "specified demand-side measure", representing no less than

(i) an average of 1% of the public utility's plan portfolio's expenditures per year over the portfolio's period of expenditures, or

(ii) an average of $2 million per year over the portfolio's period of expenditures;

(f) one or more demand-side measures intended to result in the adoption by local governments and first nations of a step code or more stringent requirements within a step code. ***, and***

(e) by adding the following subsection:

(2) The commission, when considering whether a plan portfolio is adequate under subsection (1), may consider a demand-side measure that is not included in the plan portfolio to be a part of the plan portfolio.

3 Section 4 is amended

(a) in subsection (1.1) by striking out "The commission***" and substituting "***Subject to subsection (2), the commission***",***

(b) in subsection (1.1) (c) by striking out "not referred to in section 3 (a)***" and substituting "***that is not referred to in section 3 (1) (a) and that is not a charity program***",***

(c) in subsection (1.1) by adding the following paragraph:

(d) the benefit of the demand-side measure is what it would have been had no step code been adopted in the Province. ***,***

(d) in subsection (1.5) by adding ", other than a demand-side measure referred to in section 3 (1) (a) or a charity program,***" after "***must determine that a demand-side measure***",***

(e) in subsection (1.5) (b) (iii) by striking out "33%***" and substituting "***40%***",***

(f) in subsection (1.8) by adding the following paragraph:

(a.1) a charity program, ***,***

(g) in subsection (1.8) (c) by striking out "section 3 (a)***" and substituting "***section 3 (1) (a)***",***

(h) in subsection (2) by striking out "section 3 (a)***" and substituting "***section 3 (1) (a) or a charity program***", and***

(i) by repealing subsection (2) (b) and substituting the following:

(b) in using the total resource cost test, make the adjustments referred to in subsection (1.1) (a) and (b) and then increase the value of the benefit of the demand-side measure by 40%.

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix E

Government Mandate Letter and BC Hydro Service Plan

BRITISH COLUMBIA

April 18, 2018

Mr. Kenneth G. Peterson
Chair
BC Hydro
18th Floor, 333 Dunsmuir Street
Vancouver, BC V6B 5R3

Dear Mr. Peterson:

On behalf of Premier John Horgan, thank you for your service to the people of British Columbia. The Province remains committed to working with our Crown agency partners to deliver on the Government's commitments to British Columbians; to help make life more affordable for people, invest in services and build a strong, sustainable economy.

This Mandate Letter outlines the guiding principles of the Government which should inform the preparation of your three-year Service Plan for *Budget 2018*. This Mandate Letter also confirms your organization's mandate, provides Government's annual strategic direction and sets out key performance expectations for the 2018/19 fiscal year.

The Government made three key commitments to British Columbians. All ministries and Crown agencies are expected to work together to help the Government achieve these commitments.

Our first commitment is to make life more affordable. We expect all public sector organizations to support the Government's agenda to help manage the daily cost of living for British Columbians.

Our second commitment is to deliver the services that people count on. Many of the programs and services that British Columbians access on a regular basis are delivered by Crown agencies. We want to build on programs that are working well, and make improvements where needed, to ensure British Columbians get quality and timely customer service from public sector organizations across the Province.

Our third key commitment is to build a strong, sustainable, innovative economy that works for everyone. The Government believes that public sector organizations have a key role to play in supporting broad-based economic growth in every region of the Province.

.../2

Ministry of Energy, Mines and Petroleum Resources
Office of the Minister
Mailing Address:
PO Box 9052, Stn Prov Govt
Victoria, BC V8W 9E2
Telephone: 250 953-0900
Facsimile: 250 356-2965

To support true and lasting reconciliation with Indigenous Peoples in British Columbia, the Government is fully adopting and implementing the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP), and the Calls to Action of the Truth and Reconciliation Commission (TRC). Please ensure that going forward your organization incorporates the UNDRIP and TRC, given the specific mandate and context of your organization.

As the Minister responsible for BC Hydro, I expect that you will make substantive progress on the following priorities and incorporate these priorities when developing the goals, objectives and performance measures for inclusion in the Service Plan:

- Complete the Site C Project by November 2024, at a total cost of no more than $10.7 billion, provide quarterly progress reports in accordance with the June 2015 Reporting and Accountability Framework, and:
  - enhance project oversight by adding an independent expert Project Assurance Team to supplement the Site C Project Board;
  - work with the Ministry of Transportation and Infrastructure and Treaty 8 First Nations to re-design the re-alignment of Highway 29, and where possible, provide opportunities to Treaty 8 First Nations to participate in delivering this work;
  - work with the Ministry of Transportation and Infrastructure and Treaty 8 First Nations to re-design the re-alignment of Highway 29, and work with project contractors to ensure that project benefits assist local communities and increase opportunities for apprentices, Indigenous workers, and other equity groups, with the aim to provide meaningful jobs and training;
  - continue to engage with Treaty 8 First Nations to seek additional solutions to mitigate the adverse impacts of Site C, and to advance reconciliation;
- Implement affordability measures, such as low income rates and expanded demand-side management programs targeted to low income ratepayers;
- Develop, in cooperation with the Ministry of Energy, Mines and Petroleum Resources (EMPR), a refreshed plan to keep electricity rates low and predictable over the long-term while making significant investments to expand the system and maintain aging infrastructure;
- Work with the Ministry to complete and begin to act on a comprehensive review of BC Hydro's activities, performance and organizational structure to identify potential efficiencies and revenue generating opportunities that could benefit ratepayers, and ensure that the organization is positioned to deliver on BC Hydro's objectives and the Government's priorities;

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- Support the creation of a roadmap for the future of BC energy that will drive innovation and the electrification of BC's economy, expand energy efficiency and conservation programs, generate new energy responsibly and sustainably, and create lasting good jobs across the Province;
- Provide leadership in advancing the Government's climate action strategies, including through electrification, fuel switching, and energy efficiency initiatives in the built environment, transportation, oil and gas, and other sectors;
- Work with EMPR, the Ministry of Finance and Indigenous groups to make recommendations by fall 2018 for new Indigenous-focused clean energy and/or clean capacity power procurement;
- Provide comprehensive quarterly and annual performance reports to the Deputy Minister of EMPR on the status of BC Hydro finances and forecasts, as well as other initiatives and directions approved by the BC Hydro Board and the Minister of EMPR. As and when appropriate, also update the Deputy Minister of EMPR on other emerging trends and issues as they occur;
- Continue to deliver planned capital projects on time and on budget to maintain the reliability of the system, while providing community benefits and training and apprenticeship opportunities;
- Perform system upgrades where necessary to ensure that BC Hydro is well-positioned to connect future customers in a timely and cost-effective manner; and
- Maintain or improve customer satisfaction by providing timely and responsive service.

The Crown Agencies and Board Resourcing Office (CABRO) at the Ministry of Finance has lead responsibility for overseeing and maintaining the Public Sector Organizations Governance Framework and provides leadership for the merit-based appointment of qualified and competent individuals to the boards of Crown agencies.

BC Hydro is asked to work closely with CABRO through your ministry contact on board appointments, all governance matters including orientation and training of board members, and meeting public sector reporting requirements under the *Budget Transparency and Accountability Act*.

Each board member is required to acknowledge the direction provided in this Mandate Letter by signing this letter. The Mandate Letter is to be posted publicly on your organization's website after Budget Day 2018 following the release of your organization's Service Plan.

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I have appreciated your support as Board Chair to me as Minister responsible in the first few months of our Government's term in office. I look forward to ongoing dialogue and engagement going forward through our scheduled meetings and other communication channels between my Ministry and your organization. Part of that engagement process includes regular meetings between your communications staff and the appropriate Government Communications and Public Engagement staff who provide support to your ministry responsible.

Once again, thank you to you and your Board of Directors for your commitment to public service. Together, we will work to build a better British Columbia.

Sincerely,

Michelle Mungall
Minister of Energy, Mines and Petroleum Resources

Date: April 18, 2018

Kenneth Peterson
Chair

Date: May 15, 2018.

Bill Adsit, Director

Len Boggio, Director

Robert Gallagher, Director

Debra Hanuse, Director

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James P. Hatton, Director

Valerie Lambert, Director

Janine North, Director

John Nunn, Director

John Ritchie, Director

Chris Sanderson, Director

cc: Honourable John Horgan
Premier

Mr. Don Wright
Deputy Minister to the Premier and Cabinet Secretary

Ms. Lori Wanamaker
Deputy Minister
Ministry of Finance

Mr. David Galbraith
Associate Deputy Minister and Secretary to Treasury Board
Ministry of Finance

Mr. Dave Nikolejsin
Deputy Minister
Ministry of Energy, Mines and Petroleum Resources

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Mr. Chris O'Riley
President and Chief Operating Officer
BC Hydro

Mr. Bill Adsit
Director
BC Hydro

Mr. Len Boggio
Director
BC Hydro

Mr. Robert Gallagher
Director
BC Hydro

Ms. Debra Hanuse
Director
BC Hydro

Mr. James P. Hatton
Director
BC Hydro

Ms. Valerie Lambert
Director
BC Hydro

Ms. Janine North
Director
BC Hydro

Mr. John Nunn
Director
BC Hydro

Mr. John Ritchie
Director
BC Hydro

Mr. Chris Sanderson
Director
BC Hydro

BC Hydro and Power Authority

2019/20 – 2021/22
SERVICE PLAN

February 2019

For more information on BC Hydro contact:

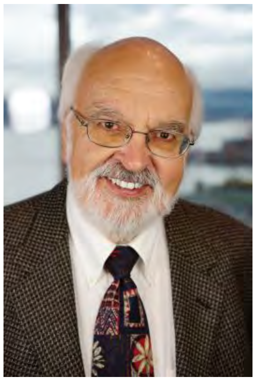
333 Dunsmuir Street
Vancouver, B.C.
V6B 5R3

Lower Mainland
604 BCHYDRO
(604 224 9376)

Outside Lower Mainland
1 800 BCHYDRO
(1 800 224 9376)

Or visit our website at
bchydro.com

Board Chair Accountability Statement



The 2019/20 – 2021/22 BC Hydro Service Plan was prepared under the Board’s direction in accordance with the *Budget Transparency and Accountability Act*. The plan is consistent with government's strategic priorities and fiscal plan. The Board is accountable for the contents of the plan, including what has been included in the plan and how it has been reported. The Board is responsible for the validity and reliability of the information included in the plan.

All significant assumptions, policy decisions, events and identified risks, as of January 31, 2019 have been considered in preparing the plan.
The performance measures presented are consistent with the *Budget Transparency and Accountability Act*, BC Hydro’s mandate and goals, and focus on aspects critical to the organization’s performance. The targets in this plan have been determined based on an assessment of BC Hydro’s operating environment, forecast conditions, risk assessment and past performance.

Kenneth G. Peterson
Board Chair

Table of Contents

Strategic Direction and Alignment with Government Priorities

BC Hydro is one of the largest electric utilities in Canada and is publicly owned by the people of British Columbia. We generate and provide electricity to 95 per cent of B.C.'s population and serve over four million people. The electricity we generate and deliver to customers throughout the province powers our economy and quality of life.

Our mission is to safely provide reliable, affordable, clean electricity throughout B.C. We have set out a three-year plan with strategies, performance measures and targets, aligned with the objectives in the B.C. Government's Mandate Letter to BC Hydro, to fulfill our mission on behalf of our customers and the Province.

BC Hydro's electricity system was largely built in the 1960s, 1970s and 1980s, and B.C.'s population and economy continue to grow. BC Hydro is upgrading and maintaining aging assets and building new infrastructure so that our customers continue to receive reliable and clean electricity. To ensure sustained economic and social benefits for ratepayers, we manage our capital portfolio with an emphasis on cost consciousness, respect for the environment and communities in which we work, and in particular, strengthening our relationships with First Nations communities.

We have the important responsibility to keep electricity rates affordable for our customers, while funding necessary investments in our electricity system. To support this goal, we are implementing the outcomes from Phase 1 of the Comprehensive Review of BC Hydro (the Comprehensive Review) and have made the necessary adjustments to our operating and capital expenditures. We will continue to strive to limit rate increases for our customers, and we will actively participate in Phase 2 of the Comprehensive Review to strategically position the corporation for long-term success in the context of rapid shifts in the global and regional energy sectors, technological changes, and provincial and federal climate strategies.

BC Hydro will continue making investments to expand the system and maintain aging infrastructure to meet our customers' growing needs, while managing our costs, keeping rates affordable and improving our service.

BC Hydro is aligned with the Government's key priorities:

Government Priorities	BC Hydro Aligns with These Priorities By:
Making life more affordable	• Ensuring our customers will benefit from affordable bills while managing our costs, exploring innovative solutions to support our customers and making investments to maintain and expand our electricity system. (Objective 3.1)
Delivering the services people count on	• Reliably meeting the electricity requirements of customers and responding to their evolving expectations by planning and investing in the system to meet future needs and by consistently improving our service. (Objective 2.1)
A strong, sustainable economy	• Continuing to implement the updated 10 Year Capital Plan so that our customers can continue to receive clean, reliable and affordable electricity. (Strategy under Objective 3.1) • Supporting the implementation of the CleanBC plan to increase British Columbians' use of cleaner energy in key sectors of the economy and shift away from reliance on fossil fuels for transportation, industry, and housing. (Strategy under Objective 4.1)

Operating Environment

As a utility that operates in a high hazard industry, we are committed to ensuring our workforce goes home safely every day and that the public is safe around our system. We are continuously working to improve our performance by understanding hazards, ensuring appropriate design of assets and related work procedures and building and strengthening our safety culture and competencies.

BC Hydro is regulated by the British Columbia Utilities Commission (BCUC). As the independent regulator of BC Hydro, the BCUC is responsible for ensuring that our customers receive safe, reliable and non-discriminatory energy services at fair rates. Current and upcoming proceedings to support affordable rates for our customers include the Fiscal 2020-Fiscal 2021 Revenue Requirements Application, which will be submitted to the BCUC in February 2019, and various Rate Design Applications. The Revenue Requirements Application will be informed by the results of Phase 1 of the Comprehensive Review, which included a full review of our business, with an emphasis on cost consciousness.

BC Hydro is developing and evaluating a number of rate design options that would help make our customers' electricity bills more affordable and provide customers with more choices. We will also continue to advance other affordability initiatives to help our customers save money on their electricity bills.

To help keep electricity more affordable for our customers, we will implement the outcomes resulting from Phase 1 of the Comprehensive Review. We will make all reasonable efforts to limit rate increases, while continuing to make significant investments to expand the system and maintain aging infrastructure.

We continue to advance critical projects to meet our long-term energy needs, including completing the Site C project by November 2024 at a cost of no more than $10.7 billion. Over the past five years (2013/14-2017/18), we have delivered 493 capital projects at a total cost of $6.9 billion, which is 0.40 per cent over budget overall, and well within BC Hydro's +5% to -5% target. We work across teams, suppliers and experts to ensure thoughtful assessment of how to successfully deliver these projects on time and on budget while respecting the unique community, environmental and Indigenous interests associated with each project.

The electricity we generate and deliver throughout B.C. meets a high standard of reliability, but we are always looking for ways to improve our service to our customers, support climate action and help power British Columbia's sustainable, innovative economy.

We are focused on delivering our renewed customer service strategy, with the goal of making it easier to do business with us and helping our customers make smart energy choices through our conservation and energy management programs, including encouraging our customers to use our clean and reliable electricity to power their homes, vehicles and businesses. We will support and align with the Province's new CleanBC plan, which outlines significant greenhouse gas (GHG) reduction measures, by powering British Columbia's economic growth with clean and renewable electricity.

BC Hydro's extensive electricity system, along with our reinvestment and expansion plans, means a significant number of Indigenous communities across the province are, or will be, impacted by our infrastructure. We continue to work to develop and sustain positive long-term relationships and better understand Indigenous interests so that their priorities are recognized in our capital programs and business operations. Our approach and results have been recently recognized through certification at a gold level through the Canadian Council of Aboriginal Business' Progressive Aboriginal Relations program. We are working to further incorporate the Calls to Action in the Truth and Reconciliation Report, the Draft 10 Principles that Guide the Province of British Columbia's Relationship with Indigenous Peoples and the United Nations Declaration on the Rights of Indigenous Peoples into our business and operations.

With thoughtful planning and prudent decision-making, BC Hydro is well positioned to safely deliver affordable, reliable, clean electricity throughout B.C., today and into the future.

Performance Plan

We have identified four key goals that reflect successful delivery of our mission: our workforce and the public will be safe; customers will experience reliable and responsive service; we will help keep electricity affordable for our customers; and, we will help make renewable, clean electricity British Columbia's leading energy source. The Safety Above All goal has moved from Goal 4 in previous Service Plan documents to Goal 1 to better reflect our commitment to safety. Other Performance Measure changes are outlined in the Discussion sections of this document.

These four key goals guide our actions, each supported by corresponding strategies, performance measures and targets. Each performance measure has a definition and rationale, as well as relevant benchmarking measures that allow a comparison of performance over time. These measures track our progress on delivering on our mission to our customers and the Province. BC Hydro's management is responsible for measuring performance against targets. Results are reported to the Board on a quarterly basis and publicly in the Annual Service Plan Report.

Goal 1: Safety Above All

Objective 1.1: Safety at BC Hydro is a core value. We are committed to ensuring our workforce goes home safely every day, and that the public is safe around our system.

Key Strategies:

- Continue to work to achieve zero fatalities and zero permanently disabling injuries. Examples of projects include: reducing electrical hazards, updating Limits of Approach; continued work on arc flash work methods; asbestos program updates; and confined space program and training.
- Reduce lost time injuries and medical aid injuries. Examples of projects include: the field/plant ergonomics program; using near misses and good catches to identify improvement opportunities; and the Return to Work/Stay at Work program.
- Build a culture to achieve excellence in safety. Examples of investments include: regular reviews of safety incidents by the senior management team; timely implementation of corrective actions that reduce risk of injuries; and completion of Safe Work Observations that identify hazards before injuries occur.
- Meet regulatory requirements. Examples of planned work include: evaluating the fall protection program; evaluating and implementing a new tracking program; identifying and ensuring compliance with new regulatory requirements when they are enacted; field-based safety audits; and building a new confined space training and certification program, ensuring worker safety and compliance with all regulations while in confined spaces.
- Build corporate systems and tools supporting excellence in safety. Examples of projects include: Safety & Health Management System; Field Access to Safety Information, which continues to improve the quality of safety information; and track Worker Protection Authorizations through a consolidated system.
- Monitor our safety performance and identify safety risks to our workers and the public.

Performance Measure(s)[1]	2017/18 Actuals	2018/19 Forecast	2019/20 Target	2020/21 Target	2021/22 Target
1.a Zero Fatality & Serious Injury[2] [Loss of life or the injury has resulted in a permanent disability]	0	0	0	0	0
1.b Lost Time Injury Frequency [Number of employee injury incidents resulting in lost time (beyond the day of the injury) per 200,000 hours worked]	0.88	1.07	0.80	0.80	0.75
1.c Timely Completion of Corrective Actions (%)	93[3]	97	95	95	97

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance

[2] Zero Fatality and Serious Disabling Injury – BC Hydro's safety performance measures do not include contractor or public safety injuries or fatalities.

[3] Previously reported as 100 per cent in the 2017/18 Annual Service Plan report, based on the previous definition for Timely Completion of Actions (see explanation in Discussion section below).

Linking Performance Measures to Objectives:

1.a Achieving our target of Zero Fatality and Serious Disabling Injury supports our objective that everyone goes home safely, every day.

1.b Focusing on Lost Time Injury Frequency indicates if our workers are experiencing fewer work place injuries. The earlier an injured worker is able to safely return to productive employment and maintain a positive connection to the workplace, the more likely the worker will experience a quick recovery.

1.c Timely Completion of Corrective Actions reduces the probability that more workers will be injured and demonstrates that we are a learning organization that is committed to addressing identified deficiencies that have a direct impact on the safety of our workforce. By implementing corrective actions in a timely manner, we will experience fewer work place injuries as systemic deficiencies are corrected.

Discussion:

In 2019/20, BC Hydro will begin to use leading indicators such as Serious Incident and Fatality Frequency to further mitigate safety risks.

Lost Time Injury Frequency's targets trend downward to reinforce our commitment to reduce workplace injuries. However, based on the number of lost time injuries we have seen year-to-date in 2018/19, we do not expect to meet our lost time frequency target of 0.85. The 2020/21 Lost Time Injury Frequency target has been adjusted from 0.75 to 0.80, based on our 2018/19 forecasted result. The implementation of the Safety & Health Management System, together with the following initiatives, will support BC Hydro in achieving future targets: 1) increased safe work observations by managers; 2) increased and more consistent use of the Return to Work/Stay at Work program; 3) increased use of Incident Management System (IMS) review calls with executive; 4) expansion of the ergonomics program; and 5) regional safety discussion calls with crews.

Our Timely Completion of Corrective Actions targets trend upward to continue focusing on meeting the due dates of these actions. 2017/18 Actuals were reported as 100 per cent in the 2017/18 Annual Service Plan Report, based on the previous definition for Timely Completion of Actions (the percentage of safety corrective actions closed within 30 days of the original scheduled due date on an annual basis). Results are now reported using the new definition of the measure (introduced in the 2018/19 – 2020/21 Service Plan): the percentage of safety corrective actions closed on or before the scheduled due date on an annual basis, with an aim to improve over time.

Goal 2: Set the Standard for Reliable and Responsive Service

Objective 2.1: BC Hydro will reliably meet the electricity requirements of customers and respond to their evolving expectations by planning and investing in the system to meet future needs and by consistently improving our service.

Key Strategies:

- Ensure the reliability of the generation, transmission and distribution system by effectively implementing capital and maintenance programs to manage overall condition of the power system and secure supply to meet customer load throughout the year.
- Safeguard the system with risk-prioritized security solutions and prepare our operations with well-practiced emergency response plans to improve overall system reliability.
- Sustain the highest, gold-level certification under the Progressive Aboriginal Relations program by maintaining leading practices focused on Indigenous employment, business development, community relationships and leadership actions.
- Continue to advance reconciliation by incorporating the United Nations Declaration on the Rights of Indigenous Peoples, the Draft 10 Principles that Guide the Province of British Columbia's Relationship with Indigenous Peoples and the Calls to Action of the Truth and Reconciliation Commission into our business.
- Continue to make it easier for customers to do business with us through a series of customer facing improvements such as increased mobile access; enabling more self-service features; exploring new, innovative rate options; expanding in-person service areas; and enhancing customer service training for employees.

- Support customers with initiatives that help them make smart energy management choices through conservation and energy efficiency, capacity reduction and low carbon electrification.

Performance Measure(s)[1]	2017/18 Actuals	2018/19 Forecast	2019/20 Target	2020/21 Target	2021/22 Target
2.a SAIDI (System Average Interruption Duration Index)[2] [Total outage duration (in hours) of sustained interruptions experienced by an average customer in a year]	3.07	3.10	3.25	3.20	3.20
2.b SAIFI (System Average Interruption Frequency Index)[2] [Total number of sustained interruptions experienced by an average customer in a year (excluding major events)]	1.51	1.37	1.40	1.40	1.40
2.c Key Generating Facility Forced Outage Factor (%)	1.81	1.80	1.80	1.80	1.80
2.d CSAT Index[3] [Customer Satisfaction Index: % of customers satisfied or very satisfied]	86.0	86.0	85.0	85.0	85.0
2.e Progressive Aboriginal Relations Designation[4]	Gold	Gold	Gold	Gold	Gold

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance

[2] Reliability targets are based on specific values, however performance within 10 per cent is considered acceptable given the reliability projection modelling uncertainty, the wide range of variations in weather patterns and the uncontrollable elements that can significantly disrupt the electrical system. BC Hydro measures reliability under normal circumstances, because major events are not predictable and largely uncontrollable. The reliability measure is therefore based on data that excludes major events. BC Hydro reviews performance during major events and takes the performance into consideration in reliability improvement initiatives.

[3] Customer Satisfaction Index (CSAT) is an index measuring customer satisfaction of BC Hydro's three main customer groups (residential, commercial and key accounts). The index is comprised of the five key drivers of satisfaction weighted equally across the three customer types.

[4] The Canadian Council of Aboriginal Business' Progressive Aboriginal Relations (PAR) Program is a certification program designed to help Canadian businesses benchmark, improve and signal their commitment to progressive relationships with Indigenous communities, businesses and people. It requires companies to set goals and assess themselves in four areas: leadership actions; employment; business development; and community relations. Each company must be certified every three years through a comprehensive review process that involves independent verification. BC Hydro was recertified at the gold level in 2018/19.

Linking Performance Measures to Objectives:

2.a & 2.b Customer reliability is measured using the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). These, along with correlated cause analysis for customer outages, support targeted investment, planning and process improvements to meet our customers' needs for reliability.

By measuring the average number of service interruptions and number of hours of sustained interruptions experienced by the average customer in a year, we are able to track our ability to reliably meet the electricity requirements of customers.

2.c A forced outage occurs when a generating unit is unable to start generating or does not stay on line as long as needed. The Key Generating Facility Forced Outage Factor will show the trend of how the generation assets are performing and support investment decisions to maintain asset reliability.

2.d The Customer Satisfaction (CSAT) Index measures customer satisfaction of BC Hydro on five key drivers: value for money; commitment to customer service; providing reliable electricity; acting in the best interest of British Columbians; and efforts to communicate to customers and communities. This measure gauges the degree to which BC Hydro is meeting customers' electricity and service needs.

2.e The Canadian Council of Aboriginal Business's Progressive Aboriginal Relations (PAR) Gold certification offers validation of BC Hydro's sustained actions towards enhanced Indigenous relations. Given BC Hydro's extensive footprint throughout the province, and its role as a Crown corporation, the comprehensiveness of the PAR certification acts as a measure for BC Hydro to ensure it is establishing relationships with First Nations built on mutual respect and that appropriately reflect the interests of First Nations communities.

Discussion:

System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) targets are based on a number of factors including long-term historic reliability trending, current year performance, previous years' investments and future years' investment plans. SAIDI's 2020/21 target has been lowered to align with improved historical performance, trends resulting from investment, planning and process improvements.

There are seven Key Generating Facilities, representing those plants with installed capacity greater than 200 MW[1]. Together they provide 90 per cent of the average annual electricity generated by BC Hydro's facilities. Key Generating Forced Outage Factor is reported as a five year rolling average and defined as the total forced outage time in a period relative to the total number of hours in the same period (usually one year). Annually, the Forced Outage Factor can be relatively volatile, and applying the historical five year rolling average can smooth the range to provide a more stable measure for which targets can be set. The objective is to keep the Forced Outage Factor below 1.8 per cent of the total number of hours per year.

Progressive Aboriginal Relations Designation – BC Hydro attained the highest, gold-level designation from the Canadian Council for Aboriginal Business in 2018/19, which is valid for a three year period.

[1] The Waneta Generating Station is not included in the Forced Outage Factor Performance Measure because BC Hydro does not manage or operate the facility.

Goal 3: Help Keep Electricity Affordable for our Customers

Objective 3.1: BC Hydro customers will benefit from affordable bills while we manage our costs, explore innovative solutions to support our customers, and make investments to maintain and expand our electricity system.

Key Strategies:

- Advance affordability initiatives and rate structures with the BCUC to help our customers manage their electricity bills.
- Make all reasonable efforts to keep rates affordable by acting on the outcomes of Phase 1 of the Comprehensive Review, including strategies to reduce future energy procurement costs.
- Submit a Revenue Requirements Application consistent with the rates forecast released in Phase 1 of the Comprehensive Review.
- Participate in Phase 2 of the Comprehensive Review, which will strategically position BC Hydro for long-term success, within the context of a rapidly evolving international and continental energy sector and provincial and federal climate action strategies.
- Implement an updated 10 Year Capital Plan so that our customers can continue to receive clean, reliable and affordable electricity.
- Continue to refine and enhance our systematic and disciplined project delivery methodology to ensure that our projects are put into service safely, on time, on budget and to a high standard of quality.
- Under the oversight of the independent Project Assurance Board, complete the Site C Project by November 2024 at a cost of no more than $10.7 billion, and provide quarterly progress updates to Treasury Board.
- Improve how we operate by improving our processes and supply chain strategies.

Performance Measure(s)[1]		2017/18 Actuals	2018/19 Forecast	2019/20 Target	2020/21 Target	2021/22 Target
3.a	Affordable Bills[2]	1st quartile	1st quartile	1st quartile	1st quartile	1st quartile
3.b	Project Budget to Actual Cost[3]	+0.40% on $6.9 billion[4]	+0.46% on $8.0 billion[5]	Within +5% to -5% of budget excluding project reserve amounts	Within +5% to -5% of budget excluding project reserve amounts	Within +5% to -5% of budget excluding project reserve amounts

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance

[2] BC Hydro calculates a relative index for each usage level within the residential category and then calculates an average of the index to create an overall ranking based on Hydro Quebec's annual report on North American electricity rates. The rankings of the 22 participating utilities are then allocated into quartiles. The 1st quartile ranking represents the six utilities that have the lowest monthly electricity bills on April 1 of a given year.

[3] This measure compares actual project costs at completion to the original approved full scope implementation budgets, not including project reserve amounts, for capital projects that were put into service during the five-year rolling period.

[4] This represents projects that went or were forecasted to go into service for the five-year period 2013/14 to 2017/18.

[5] This represents projects that went or are forecasted to go into service for the five-year period 2014/15 to 2018/19.

Linking Performance Measures to Objectives:

3.a The Affordable Bills measure is based on BC Hydro's ranking in the residential rates category in the annual Hydro Quebec report, Comparison of Electricity Prices in Major North American Cities. The report is used as a benchmark to demonstrate that our bills are affordable and predictable compared to other major North American utilities.

3.b Since 2015/16, BC Hydro has utilized the Project Budget to Actual Cost measure for the delivery of capital projects, with a target of actual project costs to be within +5% to -5% of the budget, excluding project reserves at the portfolio level. BC Hydro has consistently met this performance target, as we continue to prudently manage capital expenditures and keep affordable rates for our customers.

Discussion:

The Competitive Rates performance measure was revised to Affordable Bills to better align with the Government's affordability commitment. Affordable Bills is a more accurate name for this performance measure, as the Hydro Quebec report compares customer electricity bills in its report.

BC Hydro's residential bills have consistently been ranked in the first quartile over the past ten years. This year we are ranked third place within the first quartile based on analysis of the 2018 Hydro Quebec report, Comparison of Electricity Prices in Major North American Cities. In February 2019, BC Hydro will submit the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application that reflects the projected rates forecast from Phase 1 of the Comprehensive Review.

The Project Budget to Actual Cost measure includes Generation, Substation and Transmission Line projects managed by BC Hydro Capital Infrastructure Project Delivery. Annually, BC Hydro reports the past five years' performance at the portfolio level in delivering capital projects.

Goal 4: Help Make Renewable, Clean Power British Columbia's Leading Energy Source

Objective 4.1: BC Hydro will strengthen its legacy of renewable, clean power and conservation investments through its energy-efficiency and conservation programs, capacity reduction initiatives and support of low-carbon electrification.

Key Strategies:

- Support the implementation of the CleanBC plan to increase British Columbians' use of cleaner energy in key sectors of the economy and shift away from reliance on fossil fuels for transportation, industry, and housing.
- Support customers with initiatives that help them make smart energy management choices with conservation, efficiency, capacity reduction and low carbon electrification.
- Implement our energy conservation and energy management plan, which will exceed the *Clean Energy Act* requirement to meet at least two-thirds of future demand growth by 2020.
- Provide customers with the opportunity to access clean, renewable power to displace the use of higher carbon energy sources.
- As part of the CleanBC plan, partner with the Province and the federal government to implement a new Remote Community Clean Energy Strategy to help remote communities, with a focus on Indigenous communities, reduce or eliminate diesel generation and replace it with energy from cleaner sources.

	Performance Measure(s)[1]	2017/18 Actuals	2018/19 Forecast	2019/20 Target	2020/21 Target	2021/22 Target
4.a	Energy Conservation Portfolio (New incremental GWh/year)[2]	741	800	700	700	500
4.b	Clean Energy (%)	98.0	97.6	93.0	93.0	93.0

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance

[2] Annual targets are part of a longer-term Demand Side Management Plan that is set to fulfill the *Clean Energy Act* requirement to meet at least two-thirds of future demand growth by 2020 and BC Hydro's long term planning needs.

Linking Performance Measures to Objectives:

4.a The Energy Conservation Portfolio performance measure reflects new incremental energy savings from programs, codes and standards and conservation rates that measure BC Hydro's performance against annual energy targets. This measures the success of BC Hydro's planned conservation targets. Targets are rounded values and considered to be achieved if performance is within 10% of the stated values.

4.b The Clean Energy performance measure demonstrates BC Hydro's efforts to supply clean, sustainable, responsibly generated, affordable electricity in order to reduce GHG emissions in the province and continue to meet the 93 per cent minimum clean energy objective in the *Clean Energy Act*. The higher the per cent clean energy that BC Hydro achieves, the lower the GHG emissions in the province.

Discussion:

The targets for Energy Conservation Portfolio are based on BC Hydro's forecast of annual new incremental energy savings and do not reflect past performance and/or adjustments made to energy savings in prior years (e.g., persistence, evaluations, measurement and verification). In some cases, the timing of savings for anticipated codes and standards and timing of large customer projects can shift, which will cause actual incremental energy savings to vary from the targets that have been set for the period. Updated customer information on the timing of thermo-mechanical pulp projects and the timing of energy savings from lighting regulations resulted in increased targets for 2018/19 and 2019/20 of 800 GWh/year (gigawatt-hours per year) and 700 GWh/year respectively, followed by 700 GWh/year in 2020/21. The target of 500 GWh for 2021/22 reflects the forecasted incremental energy savings related to government enacted codes and regulations.

The Clean Energy performance measure represents the minimum threshold generation output in accordance with the B.C. Government's requirement that at least 93 per cent of electricity generation in the province be from clean or renewable resources, as specified in the *Clean Energy Act*. While actual output of the non-clean resources in the system supports system reliability and can vary depending on market conditions and water inflows to our reservoirs, BC Hydro expects that the actual performance will remain close to 98 per cent.

The New Clean Supply performance measure was removed from the 2019/20 –2021/22 Service Plan. BC Hydro will develop a new measure next year to support and align with the Government's new CleanBC plan.

Financial Plan

Summary Financial Outlook

Consolidated Statement of Operations[1, 2] ($ millions)	2018/19 Forecast	2019/20 Budget	2020/21 Budget	2021/22 Budget
Domestic	5,441	5,654	5,708	5,895
Trade	653	651	682	706
Total Revenues	**6,095**	**6,304**	**6,390**	**6,600**
Operating Costs				
Cost of energy	2,094	2,367	2,441	2,500
Personnel expenses, materials & external services[3]	1,259	1,204	1,234	1,209
Amortization	881	925	946	966
Grants and taxes	254	258	271	293
Finance charges	685	756	726	679
Other	82	108	87	94
Total Expenses	**5,255**	**5,619**	**5,704**	**5,741**
Net Income before movement in regulatory balances	**840**	**685**	**686**	**860**
Net movement in regulatory balances	**(1,264)**	**27**	**26**	**(148)**
Net Income (Loss)	**(424)**	**712**	**712**	**712**
Dividends	**59**	**-**	**-**	**-**
Net Debt[4]	**22,233**	**23,419**	**24,654**	**25,857**
Equity	**4,973**	**5,684**	**6,396**	**7,108**
Capital Expenditures[2]	**3,923**	**2,999**	**3,115**	**3,153**

[1] Table may not add due to rounding.
[2] Includes the purchase of the remaining two-thirds interest in the Waneta Dam and Generating Station in 2018/19. The transaction was approved by the BCUC in July 2018.
[3] These amounts are net of capitalized overhead and consist of the following:

	2018/19	2019/20	2020/21	2021/22
Domestic Base Operating Costs	769	778	788	793
Other	489	426	446	416
	1,259	1,204	1,234	1,209

Other largely consists of Powerex & Powertech operating costs, IFRS-ineligible capital overhead into operating costs over a 10-year period, and expenses subject to regulatory deferral.
[4] Debt figures are net of sinking funds and cash and cash equivalents.

Key Forecast Assumptions, Risks and Sensitivities

Key Assumptions	2018/19 Forecast	2019/20 Budget	2020/21 Budget	2021/22 Budget
Growth and Load				
B.C. Real Gross Domestic Product Growth (%)[1]	2.2	1.8	2.0	2.0
Domestic Sales Load Growth (%)[2, 3]	0.96	1.83	(0.59)	(0.30)
Domestic Load (GWh):				
Domestic Sales Volume (GWh)[3]	52,604	53,567	53,253	53,093
Surplus Sales Volume (GWh)	2,230	2,409	3,087	4,402
Line Loss and System Use (GWh)	5,173	5,554	5,553	5,538
Total Domestic Load (GWh)	60,007	61,530	61,893	63,033
Energy Generation				
Total System Water Inflows (% of average)	88	100	100	100
Sources of Supply to Meet Domestic Load:				
Net Hydro Generation (GWh)	43,015	44,268	44,893	45,939
Market Electricity Purchases (GWh)[4]	2,077	1,504	648	404
Independent Power Producers and Long-term Purchases (GWh)	14,631	15,449	16,040	16,346
Thermal Generation & Other (GWh)	284	309	312	344
Sources of Supply for Domestic Load (GWh)	60,007	61,530	61,893	63,033
Average Mid-C Price (U.S.$/MWh)	33.40	25.88	24.97	28.00
Average Natural Gas Price at Sumas (U.S.$/MMBTU)	3.14	2.18	2.01	1.93
Financial				
Canadian Short-Term Interest Rates (%)[5]	1.72	2.37	2.59	2.96
Canadian Long-Term Interest Rates (%)[5]	3.08	3.50	3.86	4.23
Foreign Exchange Rate (U.S.$:Cdn$)[5]	0.7755	0.7910	0.7973	0.8013

[1] Economic assumption based on calendar year, from Ministry of Finance September 2018 First Quarter Report.
[2] Includes the impact of Demand-Side Management programs.
[3] Excludes surplus sales.
[4] Assumes that gas fired power generation capability available to service domestic demand is sometimes displaced by more cost-effective market purchases.
[5] Financial assumptions from Ministry of Finance, October 2018.

Sensitivity Analysis

Factor	Change	Approximate change in 2019/20 earnings before regulatory account transfers (in $ millions)
Customer Load	+/- 1%	35
Interest Rates	+/- 100 basis points	35
Electricity/Gas trade margins	+/- 10%	20
Hydro Generation (GWh)[1]	+/- 1%	10
Exchange rates (US/ CDN)	+/-$0.01	5

[1] Assumes change in hydro generation is offset by corresponding change in net market electricity sales (i.e. increase in hydro generation is offset by increase in net market electricity sales).

Management's Perspective on the Financial Outlook

The results of Phase 1 of the Comprehensive Review were announced by Government in February 2019, and include a number of actions intended to enhance the BCUC's oversight of BC Hydro, keep rates affordable, and mitigate impacts to the Government's Fiscal Plan. The results of Phase 1 of the Comprehensive Review have been included as key assumptions in preparing the current financial projections.

The current financial projections for revenues and expenses through 2021/22 were approved by the BC Hydro Board of Directors and submitted to the Ministry of Finance in January 2019.

Major Capital Projects

Capital Expenditure by Year and Type and Function

($millions)	2018/19 Forecast	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast
Capital Expenditures by Type[1]				
Sustaining	980	978	1,093	1,175
Growth	2,943	2,021	2,022	1,978
Subtotal – BC Hydro Capital Expenditures before CIA	3,923	2,999	3,115	3,153
Contributions-in-Aid (CIA)[2]	(147)	(158)	(148)	(150)
Total – BC Hydro Capital Expenditures net of CIA	3,776	2,841	2,967	3,003
Generation	1,589	345	436	512
Transmission and Distribution	930	895	947	1,175
Properties, Technology and Other	217	229	197	148
Site C Project	1,187	1,530	1,535	1,318
Subtotal – BC Hydro Capital Expenditures before CIA	3,923	2,999	3,115	3,153
CIA	(147)	(158)	(148)	(150)
Total BC Hydro Capital Expenditures net of CIA	3,776	2,841	2,967	3,003

1. BC Hydro classifies capital expenditures as either sustaining capital or growth capital:
   - Sustaining capital includes expenditures to ensure the continued availability and reliability of generation, transmission and distribution facilities. It also includes expenditures to support the business, such as vehicles and information technology.
   - Growth capital includes expenditures to meet customer load growth and other business investments. Growth capital includes expenditures to expand existing generation assets as well as expand and reinforce the transmission and distribution system, and includes Site C and the Waneta 2/3 Interest Acquisition.
2. Contributions in aid of construction are amounts paid by certain customers toward the cost of property, plant and equipment required for the extension of services to supply electricity.

Projects over $50 million

BC Hydro has the following projects, each with capital costs expected to exceed $50 million, listed according to targeted completion date. These projects have been approved by the Board of Directors.

Major Capital Projects (over $50 million)	Targeted Completion Date (Year)	Project Cost to Dec 31, 2018 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Anticipated Total Capital Cost of Project ($ millions)
Projects Recently Put Into Service				
Ruskin Dam Safety and Powerhouse Upgrade This project improved a seismically deficient dam and rehabilitated / replaced powerhouse equipment that was brought into service between 1930 and 1950. The project included: upgrading of the right abutment; redeveloping the dam and powerhouse to meet current seismic standards for earthquakes; and replacing major generation equipment which was in poor or unsatisfactory condition.	2018 In-Service	$621	$21	$642
W.A.C Bennett Dam Riprap Upgrade Project This project addressed inadequate erosion protection on the upstream face of the W.A.C Bennett Dam. The primary driver of the project was safety of the dam itself as well as safety of the public, property, and environment downstream.	2018 In-Service	$118	$1	$119
Waneta 2/3 Interest Acqusition BC Hydro purchased Teck Resources Ltd.'s two-third interest in the Waneta Dam and associated assets in July 2018.	2018 In-Service	$1,220	$1	$1,221
Kamloops Substation This project constructed a new 100MW 138/25kV substation in the west side of Kamloops to meet expected load growth in the Kamloops service area.	2018 In-Service	$50	$6	$56

Major Capital Projects (over $50 million)	Targeted Completion Date (Year)	Project Cost to Dec 31, 2018 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Anticipated Total Capital Cost of Project ($ millions)
Ongoing				
Horne Payne Substation Upgrade Project This project expands the Horne Payne Substation with the addition of two 230/25kV, 150MVA transformers, gas-insulated feeder sections, and a new control building. This project will increase the firm capacity of the substation, add needed feeder positions, facilitate the gradual conversion of the area supply voltage from 12kV to 25kV, and allow for the implementation of an open-loop distribution system.	2019 Targeted In-Service	$63	$30	$93
John Hart Generating Station Replacement This project replaces the existing six-unit 126 MW generating station (in operation since 1947) and adds integrated emergency bypass capability to ensure reliable long-term generation and mitigate earthquake risk and environmental risk to fish and fish habitat. **John Hart forecast and life-to-date amounts include both capital costs and expenditures subject to regulatory deferral.*	2019 Targeted In-Service	$954	$31	$985*
Cheakamus Unit 1 and Unit 2 Generator Replacement This project replaces the two generators at Cheakamus generating station (in operation since 1957) to address their poor condition and known deficiencies, and increase the capacity of each unit from 70 MW to 90 MW.	2019 Targeted In-Service	$52	$22	$74

Major Capital Projects (over $50 million)	Targeted Completion Date (Year)	Project Cost to Dec 31, 2018 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Anticipated Total Capital Cost of Project ($ millions)
South Fraser Transmission Relocation Project* This project is intended to relocate certain sections of two 230kV transmission circuits (Circuit 2L62 and Circuit 2L58) from their present location adjacent to Highway 99 and in the George Massey tunnel to accommodate the replacement of the tunnel. These two 230kV circuits form a critical part of BC Hydro's transmission network supplying power to customers in Richmond, Delta and the Greater Vancouver area. ****Construction work on the South Fraser Transmission Relocation project is currently suspended pending the government's review of the George Massey Tunnel replacement.*	TBD	$32	$44	$76
Bridge River 2 Units 5 and 6 Upgrade Project This project will replace the two generators and other related equipment at Bridge River 2 to restore the historical operating capacity. These two generator units were placed in service in 1960 and are in unsatisfactory condition and unreliable.	2019 Targeted In-Service	$53	$33	$86
Downtown Vancouver Electricity Supply: West End Strategic Property Purchase This project is to acquire property rights to build a new underground substation that will upgrade the aging electricity system in downtown Vancouver.	2020 Targeted In-Service	$67	$14	$81

Major Capital Projects (over $50 million)	Targeted Completion Date (Year)	Project Cost to Dec 31, 2018 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Anticipated Total Capital Cost of Project ($ millions)
Fort St. John and Taylor Electric Supply This project will maintain adequate supply capability, reduce line losses and improve reliability to the loads in the Fort St. John and Taylor areas by re-terminating 138kV transmission lines at the new Site C switchyard, and the addition of a 75 MVA transformer and new feeder positions.	2020 Targeted In-Service	$30	$23	$53
UBC Load Increase Stage 2 Project This project is on behalf of BC Hydro's customer, the University of British Columbia, to continue to reliably meet the growing electricity needs of its Point Grey campus and the surrounding community.	2021 Targeted In-Service	$14	$41	$55
Peace Region Electricity Supply Project This project is needed to provide sufficient transmission system capacity to serve load growth and increase the reliability of electricity supply to existing customers in the South Peace. This project will facilitate reductions in provincial greenhouse gas emissions by enabling electrification of natural gas production, processing, and compression.	2021 Targeted In-Service	$56	$229	$285
LNG Canada Load Interconnection Project This project is to facilitate the interconnection of LNG Canada's facility. A new double circuit 287kV transmission line will be constructed from Minette Substation (MIN) to LNG Canada's facility and system reinforcements at MIN will also be implemented. Under BC Hydro's standard tariffs, the customer is required to pay for a portion of this project's costs.	2021 Targeted In-Service	$4	$78	$82

Major Capital Projects (over $50 million)	Targeted Completion Date (Year)	Project Cost to Dec 31, 2018 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Anticipated Total Capital Cost of Project ($ millions)
Mica Replace Units 1-4 Transformers Project This project will address the reliability and safety risks of the Unit 1-4 Generator Step-up Unit transformers at the Mica Generating Station, which are nearing end of life. There is a heightened reliability and safety risk from continuing to operate these transformers in an underground powerhouse as they age.	2022 Targeted In-Service	$4	$78	$82
G.M. Shrum G1-G10 Control System Upgrade This project will replace the controls equipment, provide full remote control capability from the remote control center, and rectify deficiencies in the current system. The condition of the legacy controls for the GMS generating units, which were originally installed in the 1960s and 1970s, is of growing concern due to increasing maintenance requirements, lack of available spare parts and decreasing reliability. The controls are well beyond their expected life, which causes operating problems and increases the risk of damage to major equipment.	2022 Targeted In-Service	$31	$44	$75
Site C Project This project will construct a third dam and a hydroelectric generating station on the Peace River approximately seven kilometres southwest of Fort St. John. It will be capable of producing approximately 5,100 gigawatt-hours of electricity annually and 1,100 megawatts of capacity. Site C will provide clean, renewable and cost-effective power in B.C. for more than 100 years. **Planned in-service date for all units.* ***Site C forecast and life-to-date amounts include both capital costs and expenditures subject to regulatory deferral. The amount includes a reserve of $708 million.*	2024* Targeted In-Service	$3,206	$7,494	$10,700**

Significant Information Technology (IT) Projects over $20 million

BC Hydro has the following IT project with capital costs expected to exceed $20 million, listed according to targeted completion date. This project has been approved by the Board of Directors.

Significant IT Projects (over $20 million in total)	Targeted Completion Date (Year)	Project Cost to Dec 31, 2018 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Anticipated Total Capital Cost of Project ($ millions)
Ongoing				
Supply Chain Applications Project This project will replace BC Hydro's existing PassPort supply chain information technology (IT) system with an SAP-based IT system and make improvements to BC Hydro's supply chain business processes for third-party materials and service acquisitions. **Anticipated Total Capital Cost for the Implementation Phase portion of the funding is pending approval by the BCUC.*	2020 Targeted In-Service	$27	$41	$68*

Appendix A: Hyperlinks to Additional Information

Corporate Governance

Information about Corporate Governance can be found at:
http://www.bchydro.com/about/accountability_reports/financial_reports/service_plan.html.

This includes links to information regarding:
- Board of Directors
- Executive Team
- Code of Conduct

Organizational Overview

Information about BC Hydro's organizational overview can be found at:
http://www.bchydro.com/about/accountability_reports/financial_reports/service_plan.html.

This includes links to information about BC Hydro's operations, governance and mandate.

Appendix B: Subsidiaries and Operating Segments

As wholly-owned subsidiaries, and like BC Hydro itself, Powerex Corp. and Powertech Labs Inc. follow best practices in corporate governance and subsidiary activities align with BC Hydro's mandate, strategic priorities and fiscal plan.

Powerex Corp.

Powerex Corp. is a wholly-owned subsidiary of BC Hydro and a key participant in energy markets across North America, buying and supplying wholesale power, renewable and low-carbon energy and products, natural gas, ancillary services, and financial energy products. Established in 1988, its export, marketing and trade business provides significant economic benefits to British Columbia.

Through its contractual agreements with BC Hydro, Powerex supports BC Hydro's electric system requirements by importing and exporting energy. Powerex also markets, through a contractual agreement with the Province, the Canadian Entitlement to the Downstream Power Benefits under the Columbia River Treaty.

The Chief Executive Officer (CEO) of Powerex reports to the Board of Directors of Powerex. The Chair of the Powerex Board ensures the Board of BC Hydro is informed of Powerex's key strategies and business activities. The Powerex CEO keeps the BC Hydro President and Chief Operating Officer (COO) and Executive Team informed of Powerex's key strategies and business activities.

Powerex operates in competitive, complex and volatile energy-markets, which can cause net income in any given year to vary significantly. Market and economic conditions, reduced hydro system flexibility, unrealized mark-to-market gains or losses and the strength of the Canadian dollar can materially impact Powerex net income. The Service Plan forecast includes annual net income from Powerex of approximately $125 million per year for 2019/20 to 2021/22. For more information, visit powerex.com.

Board of Directors:

- Ken Peterson - Chair
- Len Boggio
- James Hatton
- Valerie Lambert
- Chris O'Riley

Powertech Labs Inc.

Powertech Labs Inc., operating in Surrey since its inception in 1979, is a wholly-owned subsidiary of BC Hydro. Powertech is internationally recognized as holding expertise in a range of fields related to the electrical industry and offers services and products including: research and development, testing, technical services, software and advanced technology services to energy clients, including BC Hydro, and other sectors globally.

The President and CEO of Powertech reports to the BC Hydro President and COO. The Powertech Board is chaired by BC Hydro's President and COO and its Directors include senior Executives of BC Hydro.

The Service Plan forecast includes annual net income from Powertech of approximately $4 million per year for 2019/20 to 2021/22. For more information, visit powertechlabs.com.

Board of Directors:

- Chris O'Riley - Chair
- David Lebeter
- Mark Poweska

Other Subsidiaries

BC Hydro has created or retained a number of other subsidiaries for various purposes, including holding licences in other jurisdictions, to manage real estate holdings and to manage various risks.

All the staff and management needs of the active subsidiaries below are fulfilled by BC Hydro employees, who perform these duties without additional remuneration. Three of these subsidiaries are considered active:

BCHPA Captive Insurance Company Ltd.
Procures insurance products and services on behalf of BC Hydro.

Columbia Hydro Constructors Ltd.
Administers and supplies the labour force to specified projects.

Tongass Power and Light Company
Provides electrical power to Hyder, Alaska from Stewart, B.C. due to its remoteness from the Alaska electrical system.

Nominee Holding Companies and/or Inactive/Dormant Subsidiaries
BC Hydro's remaining subsidiaries either serve as nominee holding companies (indicated with an *) or are considered to be inactive/dormant. The inactive/dormant subsidiaries do not carry on active operations. As of December 31, 2018, these other subsidiaries consisted of the following:

1. British Columbia Hydro International Limited
2. British Columbia Power Exchange Corporation
3. British Columbia Power Export Corporation
4. British Columbia Transmission Corporation
5. Columbia Estate Company Limited*
6. Edmonds Centre Developments Limited*
7. Fauquier Water and Sewerage Corporation
8. Hydro Monitoring (Alberta) Inc.*
9. Victoria Gas Company Limited
10. Waneta Holdings (US) Inc.*
11. 1111472 BC Ltd.

BC Hydro
Power smart

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix F

Independent Audit of Capital Asset Management in BC Hydro

December 2018

INDEPENDENT AUDIT OF CAPITAL ASSET MANAGEMENT IN BC HYDRO

www.bcauditor.com

OFFICE OF THE
Auditor General
of British Columbia

CONTENTS

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The Honourable Darryl Plecas
Speaker of the Legislative Assembly
Province of British Columbia
Parliament Buildings
Victoria, British Columbia
V8V 1X4

Dear Mr. Speaker:

I have the honour to transmit to the Speaker of the Legislative Assembly of British Columbia the report, *Independent Audit of Capital Asset Management in BC Hydro.*

We conducted this audit under the authority of section 11(8), of the *Auditor General Act* and in accordance with the standards for assurance engagements set out by the Chartered Professional Accountants of Canada (CPA) in the CPA Handbook – Canadian Standard on Assurance Engagements (CSAE) 3001 and Value-for-money Auditing in the Public Sector PS 5400.

Carol Bellringer, FCPA, FCA
Auditor General
Victoria, B.C.
December 2018

The Office of the Auditor General of British Columbia would like to acknowledge with respect that we conduct our work on Coast Salish territories. Primarily, this is on the Lkwungen-speaking people's (Esquimalt and Songhees) traditional lands, now known as Victoria, and the W̱SÁNEĆ people's (Pauquachin, Tsartlip, Tsawout, Tseycum) traditional lands, now known as Saanich.

AUDITOR GENERAL'S COMMENTS

ELECTRICITY IS A NECESSITY IN OUR PROVINCE – to drive our industries and economy, and to keep our hospitals, schools, public institutions and homes functioning. BC Hydro provides more than 90% of the electricity in B.C. through a province-wide generation, transmission and distribution system.

CAROL BELLRINGER, FCPA, FCA
Auditor General

BC Hydro manages about $25 billion in assets — more than any other government entity. About 80% of these assets are thing like dams, generators, power lines and poles, substations, and transformers, which are used to provide reliable electrical service to the people of British Columbia.

BC Hydro's assets are a mix of old and new, with some approaching 100 years of service and others coming on-line this year. To manage these assets economically and efficiently requires sound asset management processes.

Asset management is the purposeful and long-term processes that aim to get the greatest efficiency, for the lowest cost, out of an asset over its lifetime. From April 1, 2017 to March 31, 2018, BC Hydro invested almost $2.5 billion to renew, repair or replace the assets it manages. For BC Hydro, good asset management practices ensure the supply and flow of electricity in British Columbia.

For this audit, we looked at whether BC Hydro is managing its assets well through appropriate information, practices, processes and systems. We found that it is. BC Hydro has good asset management practices, not by accident, but as a result of a decade-long plan and associated efforts.

Over ten years ago, BC Hydro made asset management an organizational priority. Since then, it has worked to implement international guidelines and good practice standards. It has also had its practices independently verified.

AUDITOR GENERAL'S COMMENTS

I am pleased to say that because BC Hydro is managing its assets well, we made no recommendations in this audit.

Going forward, we will continue to provide legislators and the public with information about BC Hydro's operations and programs through my office's role as BC Hydro's independent financial statement auditor and through the performance audits we plan to carry out on BC Hydro's operations.

My thanks to everyone that we spoke with for their co-operation and support during this audit.

Carol Bellringer

Carol Bellringer, FCPA, FCA
Auditor General
Victoria, B.C.
December 2018

REPORT HIGHLIGHTS

MORE THAN
90%
B.C. electricity
supplied by
BC HYDRO

BC Hydro Assets include
DAMS,
POWER LINES
AND POLES,
GENERATING
STATIONS

BC HYDRO
MANAGES
35%
OF GOVERNMENT
CAPITAL ASSETS

$2.47
BILLION
INVESTED
in fiscal 2018 to
RENEW, REPAIR OR REPLACE
the $29 billion in assets

BC Hydro
successfully made
ASSET MANAGEMENT AN ORGANIZATIONAL PRIORITY
10+ years ago

ASSET MANAGEMENT:
purposeful and long-term processes to get the **greatest efficiency,** for the **lowest cost,** out of an asset over its lifetime

NO SIGNIFICANT DEFICIENCIES SO
NO RECOMMENDATIONS

RESPONSE FROM BC HYDRO

BC Hydro appreciates the Office of the Auditor General's report on the audit of our Capital Asset Management Practices. The report highlights the progress BC Hydro has made over the past decade to define and develop our asset management processes. We are proud that the Office of the Auditor General recognizes BC Hydro's capital asset management systems and practices have generally reached an advanced level of maturity.

Although no recommendations were made as a result of the audit, BC Hydro is committed to ongoing improvements of our asset management processes to help us continue to deliver clean, reliable, and affordable electricity to our customers. One example is a recent organizational change which merged all of our power system asset management groups into one department to increase alignment and get the highest value from investments in our system. In addition, we have a number of initiatives underway that will further strengthen asset management with a focus on:

- mitigating high priority safety, environmental and financial risks;
- managing our assets using a life-cycle approach; and,
- meeting customer demand growth.

BC Hydro would like to thank the Office of the Auditor General for conducting the audit of our Capital Asset Management Practices. The conclusions of the audit confirm that BC Hydro has taken the right direction in developing its asset management capabilities.

ABOUT THE AUDIT

BACKGROUND

BC Hydro operates the largest electricity generation, transmission and distribution network in British Columbia (Exhibit 2). The network largely comprises assets such as dams, electricity generation equipment, transmission lines, transformers and power poles, all of which must be kept under scrutiny, periodically maintained and eventually renewed or replaced.

BC Hydro operates equipment and facilities that range widely in age. Its electricity generation and distribution system was largely established and expanded between 1940 and 1985. Some facilities, such as the Ruskin Dam (Exhibit 1), near Mission, are even older.

The average age of BC Hydro's generating units is over 40 years, with a number of components in the oldest facilities exceeding 85 years. The older generating, transmission and distribution assets continue to contribute to the network at or near their full capacity, and an increasing number of assets are reaching the end of their service life. Some have exceeded their life expectancy and require replacement or major investment to extend their service life.

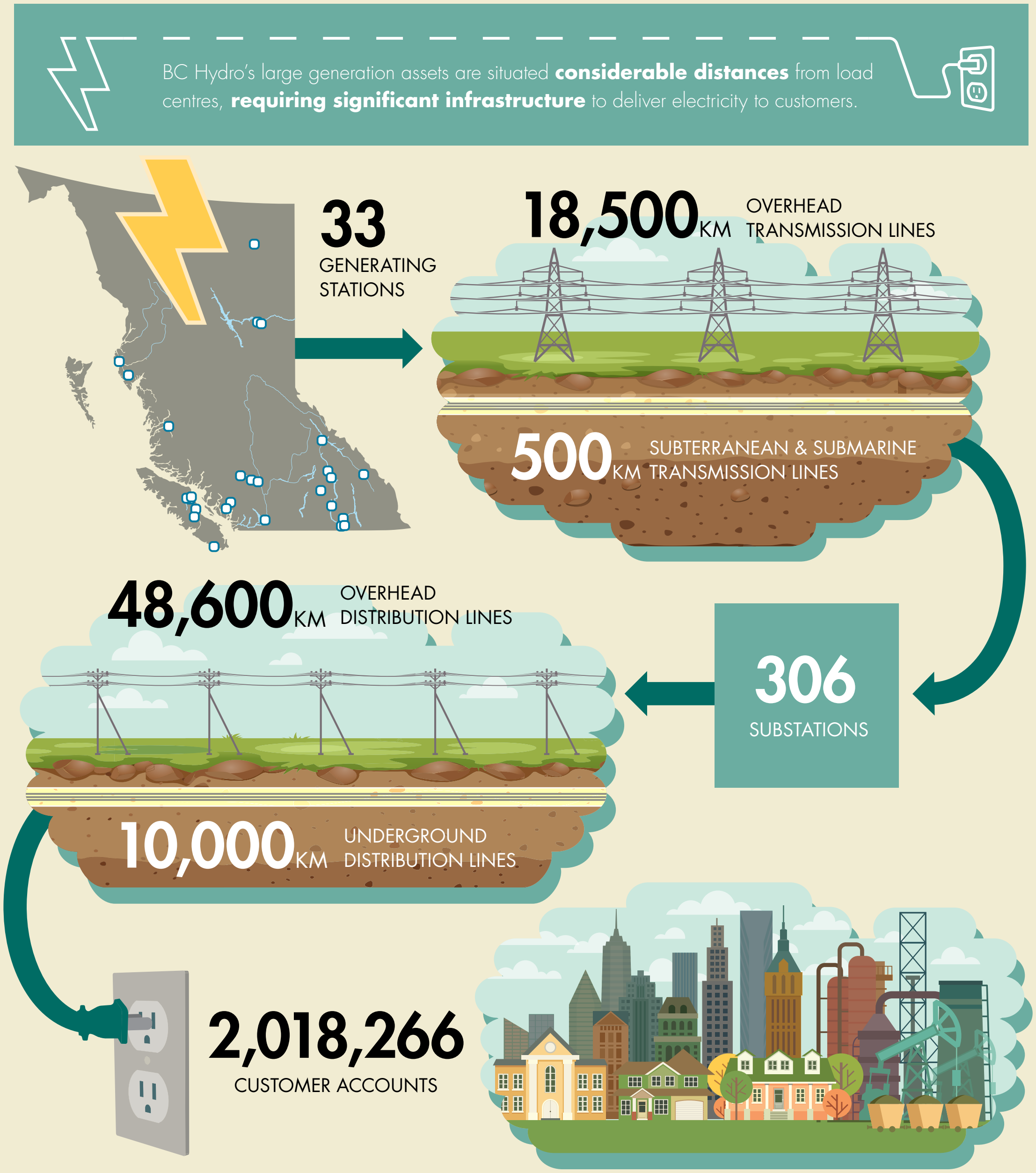
In any aging population of assets, maintenance requirements can be expected to increase and performance to decline because of degradation over time. The oldest parts of BC Hydro's network, including assets such as transmission lines, dams

Exhibit 1: Ruskin Dam and its generating station, which began operating in 1930, are currently being improved and seismically upgraded.

Source: BC Hydro

ABOUT THE AUDIT

Exhibit 2: BC Hydro generation and distribution network



Source: Office of the Auditor General of British Columbia with information from BC Hydro F2017-F2019 Revenue Requirements Application

ABOUT THE AUDIT

and power generating facilities, are already receiving attention or are due for renewal.

For example, as part of the John Hart Generating Station Replacement Project, BC Hydro is replacing generating facilities from the late 1940s that had a less efficient power output. Exhibit 3 shows the specification plate for a generator at the facility, near Campbell River, that has been in service continuously since 1948.

Exhibit 3: Generator at John Hart Generating Station, in continuous service since 1948

Source: Office of the Auditor General of British Columbia

BC Hydro's assets are typically costly to renew or replace, even though the return in service life is long. Electricity-generating assets, for example, have average expected lifespans of 40 to 50 years. The Mica Dam facility (Exhibit 4) near Revelstoke has operated for 45 years. Its powerhouse was recently modified to include two new 500-megawatt generating units, which translates into enough power to supply 80,000 homes.

Over the last five years, BC Hydro has completed 493 capital projects at a total cost of $6.9 billion. For the fiscal year that ended in March 2018, completed capital projects aimed at renewing and expanding the generation, transmission and distribution system totalled $1.6 billion. For the period 2017 to 2026, BC Hydro has forecast an annual average of approximately $2.3 billion per year to refurbish, upgrade and expand its existing generation, transmission, distribution, property and technology assets.

This audit focuses on the system BC Hydro uses for looking after its assets. Asset management at BC Hydro, as at any other asset-intensive business in

Exhibit 4: Mica Dam

Source: BC Hydro

ABOUT THE AUDIT

WHAT IS A CAPITAL ASSET, A CAPITAL PROJECT AND A CAPITAL PROGRAM?

A capital asset includes property of any kind that provides service to an organization for more than one year. Examples are land, buildings and furniture, computers and software, power plants and machinery, vehicles, power poles and towers.

A capital project is an activity that creates a new capital asset or improves the capacity or life span of an existing one. A capital program is a series of capital projects.

the public sector, involves knowing where all assets are located and their condition at a given time. It also involves having a plan in place, and the funding available, to repair, renew or replace assets without interrupting electrical service to the public.

We undertook this audit because good asset management is critical to BC Hydro's success as a reliable energy provider. Our independent assurance work provides BC Hydro with feedback on its self-assessed level of management capability in this area, and also provides the Legislative Assembly of British Columbia with an assessment indicating how well developed BC Hydro's asset management practices are relative to best practices worldwide.

AUDIT SCOPE

We looked at whether BC Hydro has the information, practices, processes and systems needed to support good asset management. We looked specifically at their generation, distribution and transmission assets and not things like vehicles, buildings and computers. In order to assess this, we looked at the following specific elements:

- information collection:
  - setting strategic asset management direction
  - establishing service levels required
  - forecasting future demand for assets
  - collecting information and knowledge about assets
  - monitoring asset performance and condition
- life-cycle management:
  - life-cycle decision making
  - risk management
  - operational planning
  - capital investment planning
  - financial planning
- systems and practices:
  - asset management leadership and teams
  - asset management plans
  - management systems
  - asset management information systems and tools
  - service delivery models
  - audit and improvement

ABOUT THE AUDIT

Good performance in these elements greatly improves the likelihood of good asset management—but doesn't guarantee it. Other factors, such as the available funding, are also key to success. We did not look at whether capital expenditure levels were sufficient to obtain good asset management results at BC Hydro, as that responsibility lies with BC Hydro and its regulator, the BC Utilities Commission.

We conducted our fieldwork between September 2016 and December 2017. Subsequently, we reviewed our finalized assessments with BC Hydro to determine whether additional evidence was available. Our work was not continuous over this period or afterward, as staff worked on multiple audits at the same time.

AUDIT METHOD

We asked BC Hydro to self-assess its asset management maturity by applying an agreed-upon set of internationally developed asset management maturity criteria. BC Hydro returned its self-assessment results along with documentation supporting its assessment scores.

We considered BC Hydro's assertions and its documentation as part of our own examination. We supported our examination by interviewing BC Hydro professionals on their asset management practices and requesting additional documentation. We followed up on specific issues where we needed clarification. We also made site visits, including visits to the John Hart Generating Station near Campbell River, the G.M. Shrum powerhouse and the W.A.C. Bennett Dam, and BC Hydro's administration offices in Burnaby.

This report is dated November 27, 2018—the date on which we received and accepted BC Hydro's acknowledgement that it had provided all the information we needed in order to conclude on the objective of our audit.

AUDIT OBJECTIVE AND CONCLUSION

AUDIT OBJECTIVE

The objective of this audit was to determine whether BC Hydro has good asset management practices.

AUDIT CONCLUSION

We concluded that BC Hydro had demonstrated good asset management practices.

AUDIT CRITERIA SUMMARY

We derived a set of asset management maturity criteria from the 2015 *International Infrastructure Management Manual* (IIMM). The particular self-assessment grid we used was developed by, and used with the permission of, the New Zealand Tertiary Education Commission (see Appendix). This New Zealand grid reflects the most recent 2015 edition of the IIMM. This approach provided an international perspective on good asset management practice. BC Hydro accepted the use of these maturity criteria.

We chose this set of criteria with a view to applying them to other asset-intensive public-sector organizations. We hope to thereby promote asset management literacy and continuous development toward best practices in asset management within the B.C. public sector.

KEY FINDINGS

OVERALL, WE FOUND THAT BC HYDRO'S CAPITAL ASSET MANAGEMENT SYSTEMS AND PRACTICES REACHED GENERALLY ADVANCED MATURITY LEVELS

WE FOUND NO SIGNIFICANT deficiencies in BC Hydro's asset management practices. Based on mutually agreed audit criteria, we found that BC Hydro:

- has collected the information it needs to support good asset management practices
- has asset life-cycle management processes that meet good practice principles
- has systems and practices in place that enable good asset management practices

BC Hydro has reached its generally advanced level of asset management maturity as a result of a concerted effort, over at least 10 years, to build its asset management practices (see Exhibit 5). This included adopting the publicly available specification for the optimal management of physical assets and a variety of internal and external assessments, which have motivated a range of improvements that are still changing the organization.

Changes to date have included identification and reduction of deficiencies, as well as reduction of barriers between organization units. Many of the good processes and practices that we observed at BC Hydro are a direct result of the efforts of the past decade.

PUBLICLY AVAILABLE SPECIFICATION FOR THE OPTIMAL MANAGEMENT OF PHYSICAL ASSETS (PAS55)

PAS 55 set out the requirements for an asset management system for the management of physical assets and asset systems over their life cycles. The specification was produced in 2004 by the UK firm BSI, in response to demand from industry for a standard for asset management.

At the time BC Hydro used it, the standard applied to any organization where physical assets were a principal means to achieving an organization's goals. PAS55 has now been superseded by international standard ISO 55001 which has similar objectives.

Source: BSI Group, https://bsigroup.com/

KEY FINDINGS

Information collection

Asset information is current and reliable

BC Hydro has collected the information it needs to support good asset management practices.

BC Hydro knows the service requirements that its electricity-generating, transmission and distribution capability must meet. This knowledge is informed by information about its assets that is current, comprehensive and routinely updated. Within its asset knowledge base, BC Hydro keeps records of asset condition and monitors asset performance, information that in turn informs decision-making and planning functions.

BC Hydro uses an equipment health rating methodology, which captures in a standardized way the actual performance of equipment, relative to design specifications and operational expectations, as well as maintenance activity and service life estimates. BC Hydro has been working to ensure that these records are all up to date and has put in place monthly inter-unit meetings to discuss emerging equipment issues or unanticipated events that could affect asset performance and trigger needed action.

Load forecasting process is robust

BC Hydro has a load-forecasting capability that compares favourably with industry standards. The process it uses includes three components:

- projecting what will drive residential and commercial demand at a future date
- conducting sensitivity analyses to adjust for various demand outcomes
- producing a set of demand probability scenarios (low, medium and high peak load forecasts) which can be applied to strategic planning

BC Hydro uses electricity load forecasting to estimate the timing, location and size of capital investments needed to meet anticipated electricity demand. Many of the assets BC Hydro uses to meet demand, such as dam facilities, generating stations, transmission lines, and rights of way on land, take many years to plan, permit, construct and commission. This lead time means BC Hydro must act at the right time to ensure that it has the energy capacity its customers will draw from many years from now.

Forecasting future peak demand enables asset managers to evaluate, plan, reconfigure and implement a revised system to supply enough energy to meet the expected load on the electrical grid.

The primary factors that BC Hydro considers in estimating future peak energy demands include forecasts of housing starts, trends in energy use, projections of the province's gross domestic product, and estimates of changes in employment and retail sales. Calculations of future demand also attempt to take into account the impact of commercial expansions or reductions and emerging trends, such as growth in reliance on electrical vehicles and use of LED lighting. For their largest 190 customers, BC Hydro develops individual projections based on information provided by these customers plus government data and third party expert reports.

KEY FINDINGS

Other factors, however, such as unforeseen labour disruptions, recessions, changes in resource commodity prices for timber and minerals, and temporary or permanent closures of businesses that affect voltage at specific locations, create uncertainty. BC Hydro's predictive demand scenario modelling factors in: gross domestic product, likely weather impacts, and external variables, such as commodity prices affecting energy consumption.

Life-cycle management

Life-cycle planning meets expectations

BC Hydro has asset life-cycle management processes that follow good practice principles.

Continual improvement based on lessons learned is built into operational plans. For example, asset maintenance standards and instructions and safety procedures are regularly reviewed. Subject matter experts and engineering reports are used to identify root causes and trends when a failure or incident occurs. Preventive maintenance required to meet regulatory requirements is always funded and resourced to the full extent.

Management has identified the most critical assets and works to sustain them by focusing on the following factors:

- safety and security of assets
- current condition of assets
- asset characteristics and specifications
- availability of skilled professionals and materials
- time when assets can be out of service
- changes in regulation and standards
- procurement lead times for materials and labour

BC Hydro manages the interaction between these factors and its service delivery objective, which is to produce a reliable supply of energy. For example, some degree of equipment redundancy is built into the network, so that if a component fails the service demand can be met in other ways.

BC Hydro also has a mature and well-documented asset maintenance program that is aligned with its objectives as an organization.

Capital planning balances asset investment with the need to manage cost

The three priorities for expenditure in BC Hydro's current 10-year capital investment plan are managing growth, maintaining and renewing assets, and dam safety. BC Hydro is funding improvement and expansion projects in all three areas within an annual funding cap. That means, for example, changes in foreign currency, trade tariffs or new technologies that drive up costs must be accommodated without exceeding the cap.

Capital investment plans are developed after all of the business units have identified their specific needs; programs and projects are then created to meet those needs as the plans are developed. An annual prioritization process decides which of the many projects will proceed and which will have to wait to keep capital spending caps from being exceeded.

KEY FINDINGS

The prioritization allows certain projects to advance toward completion each year and pushes others further out. Near term focus on capital expenditure by BC Hydro takes precedence over projects that will be funded later.

BC Hydro's ten year plan is made up of projects with different levels of cost certainty. Projects starting in the first three years of the plan have the most accurate cost estimates. Projects starting after year three are rougher forecasts. To compensate for this uncertainty and keep future costs close to the plan, Hydro uses an annual funding target (limit). Given that costs typically rise over time, projects may have to be delayed or scaled back to keep the overall plan within the funding target. Hydro therefore achieves a higher level of certainty about the cost of projects by reducing the level of certainty that projects in the later years of the plan will be built as planned.

BC Hydro explained that it is prohibitively costly to prepare full cost estimates for projects that won't start for several years.

However, it also means that BC Hydro cannot always determine the full cost associated with delaying projects, because it only has detailed costs for the near term. Impacts can include real cost increases, such as labour and equipment, loss of revenue, and increased maintenance and operational costs. Cost changes could also be decreases resulting from new technologies or alternative energy sources. BC Hydro looks at these impacts in its annual project prioritization if a project will be deferred by three years. This means that some cost consequences of delay within the 10-year capital plan are unknown.

However, advanced maturity requires a high level of project cost certainty throughout a 10-year capital plan. This is a higher level of certainty than what is achieved in years 4-10 of Hydro's plan. However, in BC Hydro's case, this is not a deficiency, and as a result we are not making a recommendation.

BC Hydro's practices in this regard make sense. Consider, for example, the needs of BC Hydro compared with those of a school district experiencing declining enrolment. The school district will not need to plan for new assets and can focus on the maintenance and possible retirement of existing facilities. It should therefore be able to cost-effectively meet all the significant indicators of advanced maturity for capital investment planning. By contrast, BC Hydro must make a complex estimation of the need for power and the resulting income from customers available to grow capacity while allocating investments across a wide array of asset types of different ages and manufacture. Additionally, accurately costing the largest projects requires costly professionals like designers, engineers and quantity surveyors to put in significant amounts of time. Greater certainty therefore takes a lot of time and comes at a significant cost.

More specific to BC Hydro's situation is the dynamic environment in which it operates. In planning it must try to estimate the impacts of emerging technologies and energy efficiency gains on electricity demand, while at the same time responding to government policy direction, such as that associated with the *Clean Energy Act*. BC Hydro's regulator, the BC Utilities Commission, looks at this operating environment to the degree which it is allowed to given government direction.

KEY FINDINGS

Systems and practices

Leadership and teams are supported by learning, development and trades training strategies

We expected BC Hydro's commitment to asset management to be reflected in the leadership roles in the business units. We found there is alignment of asset management objectives, such as reliability, with asset management methodology and responsibilities of professionals involved. The technical capacity in the business units is sufficient to design projects for the 10-year plan of capital investments.

Asset management plans are updated each year

We found that asset performance expectations and future demand forecasts are applied to asset management planning. Significant levels of stakeholder engagement are factored into planning. One example is the facility planning process BC Hydro uses to keep stakeholders informed of known issues and opportunities. Asset management plans are reviewed, improved and updated annually.

Service delivery focus is on best value

BC Hydro has to buy supplies and services from external sources to support its asset management maintenance programs and capital projects. We expected that the risks, benefits and costs of various service delivery options had been considered and that the option with the best value was implemented. In BC Hydro's capital asset management framework, all projects over $50M must be assessed for suitability for alternative procurement.

We found there are slightly different procurement plans/policies in place for different departments within BC Hydro. There is a plan to align procurement policies to ensure consistency of practices across the organization.

BC Hydro has a generally advanced level of maturity in asset management, as indicated in Exhibit 5. Its success in this regard is a result of concerted effort over several years by a set of skilled professionals focused on ensuring that a reliable source of electrical power will be supported by a mature asset management practice.

Exhibit 5: BC Hydro's Asset Management maturity score - out of 100 points

Understanding and Defining Requirements	
Setting the Strategic Direction	95
Establishing Levels of Service	95
Forecasting Future Demand	95
Collecting Asset Information (Asset Knowledge)	85
Monitoring Asset Performance and Condition	85
Lifecycle Planning	
Lifecycle Decision Making	90
Risk Management	80
Operational Planning	90
Capital Investment Planning	80
Financial Planning	90
Asset Management Enablers	
AM Leadership and Teams	90
AM Plans	85
Management Systems	80
AM Information Systems and Tools	85
Service Delivery Models	90
Audit and Improvement	85

Intermediate maturity   Advanced maturity

Source: Office of the Auditor General of British Columbia

AUDIT QUALITY ASSURANCE

We conducted this audit under the authority of section 11 (8) of the *Auditor General Act* and in accordance with the standards for assurance engagements set out by the Chartered Professional Accountants of Canada (CPA) in the CPA Handbook – Canadian Standard on Assurance Engagements (CSAE) 3001 and Value-for-money Auditing in the Public Sector PS 5400. These standards require that we comply with ethical requirements, and that we conduct the audit to independently express a conclusion on whether or not the subject matter complies in all significant respects to the applicable criteria.

We apply the CPA Canadian Standard on Quality Control 1 (CSQC) and, accordingly, maintain a comprehensive system of quality control, including documented policies and procedures regarding compliance with ethical requirements, professional standards, and applicable legal and regulatory requirements. In this respect, we have complied with the independence and other requirements of the code of ethics applicable to the practice of public accounting issued by the Chartered Professional Accountants of British Columbia, which are founded on the principles of integrity, objectivity and professional competence, as well as due care, confidentiality and professional behaviour.

APPENDIX: COMPLETE AUDIT CRITERIA

FOR BC HYDRO asset managers, asset planners, operators, maintainers and developers, the IIMM manual offers a reference within which the various components of a system of asset management are situated and interrelated. For those specialists at the periphery, such as regulatory, IT and financial professionals, the manual provides an asset management framework with examples.

Audit Criteria as adapted from the *International Infrastructure Management Manual*

Maturity Scale →	Aware Maturity 0-20	Basic Maturity 25-40	Core Maturity 45-60	Intermediate Maturity 65-80	Advanced Maturity 85-100
Understanding and Defining Requirements					
Setting the Strategic Direction Asset management (AM) policy supports an organization's strategic objectives. It articulates the principles, requirements and responsibilities for AM. It articulates the objectives, practices and action plans for AM improvement, audit and review processes. The AM Policy and Strategy may be incorporated into the AM Plan.	The organization is aware of the need to develop an AM Policy, but hasn't yet completed this work.	Corporate expectations are expressed in relation to the development of AM plans and objectives, such as "all departments must have a current AM plan".	AM policy and objectives are developed and aligned with corporate goals and strategy.	The scope of AM is defined and documented. How AM fits into the wider corporate environment is analyzed and implications for AM are documented in the Strategic AM Plan or AM Strategy. AM policy and objectives are reflected in departmental plans and priorities.	AM Policy and Strategy is fully integrated into the organization's business processes and subject to defined audit, review, and updating procedures.
Establishing Levels of Service Levels of service are the cornerstone of asset management and provide the platform for all life-cycle decision making. Levels of service are the outputs a customer receives from the organization. One of the first steps in developing asset management plans or processes is to find out what levels of service customers are prepared to pay for, then understand the organization's capability to deliver the levels of service.	The organization understands level of service requirements but has not documented or quantified them.	The organization has defined how assets contribute to the organizations objectives and levels of service. Customer/ user groups have been defined and their needs are informally understood.	Level of service benchmarks are in place for each major client, user or asset group. Customer/ user needs have been analyzed.	Customers/users have been consulted on significant service levels and options. The relationship between the level of service and costs is understood by the organization.	Levels of service and benchmarks are integrated into decision making, business planning and performance reporting.
Forecasting Future Demand This AM activity involves predicting changes in demand for specific service requirements over the life of the AM plan or the life of the asset pool. The ability to predict demand enables an organization to plan ahead and meet that demand, or manage risks of not meeting demand.	The organization generally understands future demand requirements but they are not documented or quantified.	Demand forecasts are based on predictions by experienced staff, with consideration of known past demands, trends and likely future growth patterns.	Demand forecasts are based on robust projections of a primary demand factor (e.g. population growth) and extrapolation of historic trends. Risks associated with changing demand are broadly understood and documented.	Demand management is considered during long term capital planning. Demand forecasts are based on mathematical analysis of past trends and primary demand factors. A range of demand probability scenarios is developed (e.g. high, med, low) as part of risk management.	Demand management is considered in strategic and project decisions. Risk assessments of different demand scenarios with mitigation actions are in place.

APPENDIX

Maturity Scale →	Aware Maturity 0-20	Basic Maturity 25-40	Core Maturity 45-60	Intermediate Maturity 65-80	Advanced Maturity 85-100
Understanding and Defining Requirements *(continued)*					
Collecting Asset Information (Asset Knowledge) Credible asset data is the foundation for enabling most AM functions. Effective planning for asset maintenance, renewal, upgrade, and replacement cannot proceed until organizations know the nature, location, capacity, and reliability of the assets they rely on for service delivery.	The organization has asset information in a variety of formats. There is an awareness of the need for an integrated asset register.	Essential asset information (e.g. type, design size / capacity, age, location) is recorded in spread sheets or data bases, but is based primarily in historical records such as "as-built". Asset information is updated and verified periodically.	As for Basic, plus there is sufficient information for valuations, replacement costs, asset age, remaining service life. Asset information generally supports planning and prioritization. Asset hierarchy, identification and attribute systems are documented. Asset data is routinely updated and tested for reliability.	As for Core, plus a reliable register of physical, financial and risk attributes recorded in an information system with data analysis and flexible reporting functionality. Systematic and documented data collection process are in place. High level of evidence based confidence in asset data.	As for Intermediate, plus detailed (component level) information on work history, type and cost, condition, performance, etc. is recorded and utilized in data analysis. Systematic and fully optimised data collection program in place with supporting metadata. There is a complete data base for core assets with minimal assumptions for non core assets.
Monitoring Asset Performance and Condition Assets are central to service delivery and meeting strategic objectives. Timely and complete performance and condition information is essential for AM and supports life cycle decision making, risk management, and operational, capital and financial planning.	Asset condition and performance data is not formally documented, or is collected in limited quantities.	Asset information and data is adequate to confirm current asset performance against AM objectives.	Asset condition and performance information is suitable to plan maintenance and renewal over the near term (5 years or less).	As for Core, plus asset condition and performance information is modelled to assess whether AM condition and level of service objectives are being met over the long-term (> 5 years). Contextual information such as forecasting demand variances is used to estimate potential performance variances.	As for Intermediate, plus the type, quality and amount of asset data are optimised to the financial and technical decisions being made. Asset performance and condition data is modeled for development and reporting of continuous improvement strategies. The data collection program is adapted to reflect asset lifecycles.
Lifecycle Planning					
Lifecycle Decision Making Lifecycle based AM planning is essential to achieve sustainable, appropriate, and affordable levels of services.	The organization recognises the benefits of lifecycle-based decision making but currently bases decisions primarily on staff judgement.	Organizational priorities are reflected in AM decision making.	As for Basic, plus formal decision making analysis/techniques are applied to major projects and programs, where criteria are based on organizational AM objectives.	As for Core, plus formal decision making and prioritization techniques are applied to operational and capital programs at the business unit, asset component level, or budget category. Past assumptions, forecasts, estimates, and decision making methodologies are tested against actual results.	As for Intermediate, plus AM objectives and targets are based on formal decision making techniques and are supported by the estimated cost and benefit or achieving targets. The decision making framework enables projects and programs to be optimized across the organization. Formal risk based sensitivity analysis is carried out and informs subsequent management decision cycles.

APPENDIX

Maturity Scale →	Aware Maturity 0-20	Basic Maturity 25-40	Core Maturity 45-60	Intermediate Maturity 65-80	Advanced Maturity 85-100
Lifecycle Planning *(continued)*					
Risk Management Risk management helps identify higher frequency and higher consequence risks, and identifies actions to mitigate those risks. This process reduces the organization's exposure to asset related risks and drives maintenance rehabilitation and renewal programs and decision making.	The organization has identified formal risk management, related to AM, as a future improvement.	Critical service and asset risks are understood and considered by senior staff involved in maintenance and renewal decisions.	A risk framework is developed. Critical assets and high risks are identified. There are documented risk management strategies for critical assets and high risks.	As for Core, plus systematic risk analysis assists key decision-making. The risk register is regularly monitored, updated and reported. Risk is managed consistently across the organization. An infrastructure resilience strategy and program is in place including defined levels of service for resilience.	As for intermediate, plus a formal risk management policy in place. Risk is quantified and risk mitigation options evaluated. Risk and resilience are integrated into all aspects of decision making.
Operational Planning Operational plans document how assets will be operated on a day to day basis including activities aimed at keeping assets in service and meeting AM objectives. Operations encompasses both operational and maintenance activities. Effective operational strategies can mitigate risk, defer the need for asset replacement, minimize service downtime, reduce the impact from asset failures, increase service affordability and reduce lifecycle costs.	Operational plans and procedures (operations and maintenance) are based on historical practices (things are largely done the way they always have been).	Operating plans and procedures are available for critical operational processes.	The organizations operational structure is in place, documented and roles are assigned.	As for Core, plus operating plans and procedures (maintenance and operational) are available for all operational processes. Support requirements/ resources are in place and risk and opportunity planning is completed.	As for Intermediate, plus operational objectives and intervention levels are defined and implemented. Operational planning's alignment with organizational objectives can be demonstrated. Continual improvement can be demonstrated for all operational processes.
Capital Investment Planning Capital investment includes the upgrade, creation and/or purchase of new assets, typically to address growth or changes in levels of service requirements, or for the periodic renewal of existing assets to maintain service levels. Organizations need to plan for the long term asset requirements relative to forecasted demand and future levels of service.	Capital investment projects are identified during the annual budgeting process.	There is a schedule of proposed capital projects, with associated costs, for the next 3-5 years, based on staff judgement of future requirements.	Proposed projects have been collected from a wide range of sources and collated into a project register. Capital projects for the next three years are fully scoped and estimated. A prioritization framework is in place to rank the importance of capital projects. Asset condition, performance and levels of service are variables used to prioritize projects.	As for Core, plus formal options analysis and business case development has been completed. Priority capital projects proposed in the 3-5 year period are consistent with capital programs, reflecting the requirements of the next 10-20 years. Priority projects and programs have full cost estimates available.	Long term capital investment programs are developed using decision techniques such as predictive modeling. The organization has a reliable and approved 10-year view of its future capital requirements to meet forecast level of service requirements and the strategic choices available to meet changing fiscal or level of service requirements.
Financial Planning Poor long term financial management can lead to higher life cycle costs, and financial "shocks". Good collaboration between financial and technical asset managers is important, especially in relation to long term financial forecasts and asset condition and level of service related decisions. Robust financial budgets are a key output of any asset management planning process.	Financial planning is largely an annual budget process but there is intention to develop longer term forecasts.	10-year financial forecasts are based on extrapolation of past trends and broad assumptions about the future.	10 year+ financial forecasts are based on current comprehensive AM plans. Significant assumptions are stated. Expenditures are captured at a level useful for AM analysis.	10 year+ financial forecasts are based on current comprehensive AM plans with detailed supporting assumptions and reliability factors. Significant assumptions are specific and well reasoned. Asset expenditures are easily linked to finance databases.	10 year+ financial forecasts based on comprehensive, advanced AM plans with detailed underlying assumptions and high confidence in accuracy. Advanced financial modeling provides sensitivity analysis, demonstrable whole life costing and cost analysis for level of service options.

APPENDIX

Maturity Scale →	Aware Maturity 0-20	Basic Maturity 25-40	Core Maturity 45-60	Intermediate Maturity 65-80	Advanced Maturity 85-100
Asset Management Enablers					
AM Leadership and Teams Effective asset management requires a committed and co-ordinated effort across all sections of an organization.	Organization leadership is supportive of AM.	AM functions are carried out by small groups. Position descriptions incorporate AM roles.	AM coordination processes are established. Leadership demonstrates ownership and support for AM. There is an awareness of AM across most of the organization and broad organizational structures that support AM.	There is a consistent approach to AM across the organization and an established internal communication plan. AM is resourced, key AM roles are in place and AM duties are included in position descriptions.	Roles reflect AM requirements and AM is defined in all relevant position descriptions. There is a formal documented assessment of AM capability and capacity requirements needed to achieve AM objectives. There is a demonstrate alignment between AM objectives, AM systems and individual responsibilities.
AM Plans An asset management plan is a written representation of intended capital and operational programs for its new and existing infrastructure, based on the organizations understanding of demand, customer requirements and its own network of assets.	The organization has stated an intention to develop AM plans.	AM plans contain basic information on assets, service levels, planned work and financial forecasts (5-10 years) and identifies future AM improvements actions.	AM objectives are defined within the overall strategic context. The AM plan includes basic level attributes plus the following: - the approach to risk and critical assets is described - a top-down condition and performance assessment - future demand forecasts - descriptions of supporting AM processes - 10-year financial forecasts - a 3-year AM improvement plan.	AM strategic context analyzed with risks, issues and responses described. The AM plan includes core attributes plus the following: - analysis of asset condition and performance trends - customer engagement in setting levels of service - optimized decision making and risk techniques applied to major programs.	The AM plan includes intermediate attributes plus the following: - evidence of programs driven by comprehensive optimized decision making techniques - risk management programs and level of service/cost trade off analysis AM plan improvement program is largely complete with focus on ongoing maintenance of current practices.
Management Systems Effective management systems allow organizations to improve effectiveness and efficiency, increase customer satisfaction and better manage asset condition, performance, service delivery, risk and other factors.	The organization is aware of the need to formalize AM systems and processes but has yet to document and implement a management system with specific policies, processes, procedures, systems and reporting frameworks.	Simple process documentation in place for service critical AM activities.	A basic quality management system is in place that covers financial and technical activities. Critical AM processes are documented, monitored and subject to review.	As for core plus process documentation is implemented in accordance with AM system to an appropriate level of detail. Internal financial and technical management systems are aligned.	As for intermediate plus strong integration of all management systems within the organization. Ongoing staff training supports the effective and consistent use of management systems. Outcomes are measured and reported to support continuous improvement.

APPENDIX

Maturity Scale →	Aware Maturity 0-20	Basic Maturity 25-40	Core Maturity 45-60	Intermediate Maturity 65-80	Advanced Maturity 85-100
Asset Management Enablers *(continued)*					
AM Information Systems and Tools AM systems are an essential tool for the timely and cost effective management of assets in order to affordably meet service obligations. The large amounts of data associated with assets and AM requires information systems and tools in order to effectively deal with the extent of analysis required to fully manage assets.	The organization recognizes the benefits of using asset management information systems(AM IS), but does not have one in place.	The AM IS or asset register can record core asset attributes such as size, material etc. Asset information reports can be manually generated for AM plan input.	The AM IS or asset register enables hierarchical reporting (from component to facility level). Customer request tracking and planned maintenance functionality is enabled. The system enables manual reports to be generated for valuation and renewal forecasting.	As for core plus, there is more automated analysis, forecasting and reporting on a wider range of information including operations, maintenance, condition, performance and financial.	Financial, asset and customer service systems are integrated, interactive and enable advanced AM functions. There is forecasting of AM activity including prioritized expenditures to refurbish and upgrade assets. Asset optimization analysis can be completed.
Service Delivery Models The cost effectiveness of asset management planning is proven in the efficient and effective delivery of services at an operational level.	The organization has clearly allocated service delivery roles (internal and external) and generally follows historic approaches.	Service delivery roles are clearly allocated internally and externally and generally follow historic approaches or industry customs and practices.	Core functions are defined. A procurement strategy/policy is in place. Internal service level agreements are in place with primary internal service providers and contracts for primary external service providers.	Risks, benefits and costs of various outsourcing options are determined and considered. Competitive tendering practices are applied with integrity and accountability. Periodic reviews are conducted to identify the best value delivery mechanism for each major AM activity.	All potential service delivery mechanisms have been reviewed and formal analysis carried out. Risks, benefits and costs of various service delivery options have been considered and the best value arrangement has been identified and is being implemented.
Audit and Improvement Well performing organizations recognize the value that can be obtained from continuously improving AM policies, processes, systems and capabilities. The focus is on ensuring AM practices are appropriate to the current and long term business objectives.	The organization recognizes the need to improve AM processes and practises, but has yet to develop an improvement plan.	Improvement actions have been identified and responsibility has been allocated to appropriate staff.	Current and future AM performance is assessed and identified gaps are used to drive improvement actions. Improvement plans identify objectives, timeframes, deliverables, resource requirements and responsibilities.	As for Core, plus formal monitoring and reporting on the improvement program to the Executive Team. Project briefs have been developed for all key improvement actions. Resources have been allocated to the improvement actions.	As for Intermediate, plus improvement plans specify key performance indicators (KPIs) for monitoring AM improvement. Improvement plan key performance indicators are routinely reported.

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Appendix G

Fiscal 2017 and Fiscal 2018
Variance Explanations

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1 Introduction

This appendix provides variance explanations for BC Hydro's energy sales and revenues, energy supply and energy costs, operating costs and capital expenditures and additions between the plan amounts in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (**Previous Application**) and actual results in those fiscal years.

2 Energy Sales and Revenue Variance Explanations (Chapter 3)

Chapter 3 of the Application addresses BC Hydro's load and revenue forecast for the test period. This section compares domestic energy sales and revenue actual amounts for fiscal 2017 and fiscal 2018 with the Plan amounts from the Previous Application.

Load and revenues always have a degree of variability between forecast and actual amounts, but, as described below, the load variances are relatively small in fiscal 2017 and fiscal 2018, ranging from 0.1 per cent to 0.5 per cent. These variances are captured by the Cost of Energy Variance Regulatory accounts, meaning that customers pay only actual costs.

2.1 Domestic Energy Sales Variance Explanations

2.1.1 Domestic Energy Sales Variance Explanations - Fiscal 2017

Table G-1 compares fiscal 2017 domestic energy sales actual amounts (in GWh) against the fiscal 2017 RRA Plan, with variance explanations below the table.

Table G-1 Fiscal 2017 Domestic Energy Sales Variance

	(GWh)	Schedule Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2017 % Diff
			1	2	3 = 2 - 1	4 = 3 / 1
1	Residential	14.0 L1	18,036	18,068	31	0.2%
2	Light-Industrial and Commercial	14.0 L2	18,832	18,968	136	0.7%
3	Large Industrial	14.0 L2+L9	13,380	13,176	(204)	-1.5%
4	Other	14.0 L3 to L8	1,611	1,683	72	4.5%
5	Total	14.0 L10	51,860	51,895	35	0.1%

Actual domestic energy sales in fiscal 2017 were 35 GWh (or 0.1 per cent) higher than the demand projections included in the fiscal 2017 RRA Plan.

Actual energy sales to the residential sector were 31 GWh (or 0.2 per cent) higher than the fiscal 2017 RRA Plan, primarily due to slightly colder temperatures partially offset by lower net usage per account and lower account growth than plan.

Actual energy sales to the light industrial and commercial sector were 136 GWh (or 0.7 per cent) higher than the fiscal 2017 RRA Plan due to higher than anticipated growth in leading economic drivers, such as net employment in the province.

Actual energy sales to the large industrial sector were 204 GWh (or 1.5 per cent) lower than the fiscal 2017 RRA Plan. Most of the variance was in the oil and gas sector and LNG. Specifically, there were delays in start-up of gas loads in the oil and gas sector. Additionally, FortisBC Tilbury LNG plant operations did not increase in production as anticipated in the fiscal 2017 RRA Plan.

Actual energy sales to other customer sector were 72 GWh (or 4.5 per cent) higher than the fiscal 2017 RRA Plan, primarily due to higher than expected sales to FortisBC.

2.1.2 Domestic Energy Sales Variance Explanations - Fiscal 2018

Table G-2 compares fiscal 2018 domestic energy sales actual amounts (in GWh) against the fiscal 2018 RRA Plan, with variance explanations below the table.

Table G-2 Fiscal 2018 Domestic Energy Sales – Actuals

	(GWh)	Schedule Reference	F2018			
			RRA	Actual	Diff	% Diff
			1	2	3 = 2 - 1	4 = 3 / 1
1	Residential	14.0 L1	18,112	18,150	39	0.2%
2	Light-Industrial and Commercial	14.0 L2	18,785	18,874	89	0.5%
3	Large Industrial	14.0 L2+L9	13,323	13,440	117	0.9%
4	Other	14.0 L3 to L8	1,618	1,638	19	1.2%
5	Total	14.0 L10	51,838	52,102	264	0.5%

Actual domestic energy demand in fiscal 2018 was 264 GWh (or 0.5 per cent) higher than the demand projections included in the fiscal 2018 RRA Plan.

Actual residential sector energy sales were 39 GWh (or 0.2 per cent) higher than the fiscal 2018 RRA Plan. Identical to fiscal 2017, this was primarily due to slightly colder temperature differences than the assumed normalized values, and partially offset by lower usage per account and lower account growth than plan.

Actual light industrial and commercial sector energy sales were 89 GWh (or 0.5 per cent) higher than the fiscal 2018 RRA Plan, primarily due to sales growth to manufacturing customers.

Actual large industrial sector energy sales were 117 GWh (or 0.9 per cent) higher than the fiscal 2018 RRA Plan. Actual sales were greater than plan in the mining, wood and chemical sectors. Actual sales were also above plan in the pulp and paper sector, and the positive variance in this sector was partially offset by an unfavourable variance in the oil and gas sector as well as the FortisBC Tilbury LNG plant. Sales were above plan in the pulp and paper sector primarily due to closure risk adjustments, which were partially offset by lower than expected self-generation by our customers. Sales were below plan in the oil and gas sector due to delays in gas projects driven by various factors such as market conditions and delays in the ramp up of production at FortisBC Tilbury explains the variance in LNG sales.

Actual energy sales to the other customer sector were 19 GWh (or 1.2 per cent) higher than the fiscal 2018 RRA Plan. This variance was primarily due to higher sales than expected to FortisBC, partly offset by lower sales to the City of New Westminster.

2.2 Domestic Revenue Variance Explanations

2.2.1 Domestic Revenue Variance Explanations - Fiscal 2017

Table G-3 compares fiscal 2017 domestic revenue actuals (in $million) against the fiscal 2017 RRA Plan, with variance explanations below the table.

Table G-3 Fiscal 2017 Domestic Revenues – Variance

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2017 % Diff
			1	2	3 = 2 - 1	4 = 3 / 1
1	Residential	14.0 L11	1,915	1,916	1	0.1%
2	Light-Industrial and Commercial	14.0 L12	1,703	1,715	11	0.7%
3	Large Industrial	14.0 L13+L19	749	733	(16)	-2.1%
4	Other	14.0 L14 to L18	120	122	2	1.5%
5	Subtotal		4,487	4,486	(1)	0.0%
6	Revenue from Deferral Rider	14.0 L21	223	224	1	0.1%
7	Total	14.0 L22	4,710	4,710	0	0.0%

Actual domestic revenues in fiscal 2017 were the same as the fiscal 2017 RRA Plan, with slightly lower large industrial revenues offset by higher light industrial and commercial revenue. These revenue variances were driven by the load variances described in section 2.1.1.

2.2.2 Domestic Revenue Variance Explanations - Fiscal 2018

Table G-4 compares fiscal 2018 domestic revenue actuals (in $million) against the fiscal 2018 RRA Plan, with variance explanations below the table.

Table G-4 Fiscal 2018 Domestic Revenues – Variance

	($ million)	Schedule Reference	F2018 RRA	F2018 Actual	F2018 Diff	F2018 % Diff
			1	2	3 = 2 - 1	4 = 3 / 1
1	Residential	14.0 L11	1,991	1,997	5	0.3%
2	Light-Industrial and Commercial	14.0 L12	1,758	1,771	12	0.7%
3	Large Industrial	14.0 L13+L19	775	772	(2)	-0.3%
4	Other	14.0 L14 to L18	124	122	(2)	-1.6%
5	Subtotal		4,649	4,662	13	0.3%
6	Revenue from Deferral Rider	14.0 L21	231	233	2	0.8%
7	Total	14.0 L22	4,880	4,895	15	0.3%

Actual domestic revenues in fiscal 2018 were $15 million (or 0.3 per cent) higher than the fiscal 2018 RRA Plan. This increase is largely driven by higher light industrial and commercial load, as described in section 2.1.2. The higher load in the large industrial sector did not result in higher revenue as the actual average rate was lower than anticipated in the fiscal 2018 RRA Plan due to the different proportions of load at the various tariff rates.

3 Cost of Energy Variance Explanations (Chapter 4)

Chapter 4 of the Application addresses BC Hydro's Cost of Energy for the test period. This section compares sources of energy supply and Cost of Energy actual amounts for fiscal 2017 and fiscal 2018 with the Plan amounts from the Previous Application.

3.1 Sources of Supply Variance Explanations

3.1.1 Sources of Supply Variance Explanations – Fiscal 2017

Table G-5 compares fiscal 2017 energy supply sources actuals (in GWh) against the fiscal 2017 RRA Plan, with variance explanations below the table.

Table G-5 Fiscal 2017 Sources of Supply

	(GWh)	Schedule Reference	F2017 RRA	Actual	Diff	% Diff
			1	2	3 = 2 - 1	4 = 3 / 1
1	Water Rentals	4.0 L1	48,560	48,736	176	0%
2	IPPs and Long-Term Commitments	4.0 L5	13,375	13,644	269	2%
3	Market Electricity Purchases	4.0 L8	230	131	(98)	(43%)
4	Natural Gas for Thermal Generation	4.0 L2	224	74	(151)	(67%)
5	Surplus Sales	4.0 L9	(4,962)	(5,756)	(794)	16%
6	Net Purchases (Sales) from Powerex	4.0 L10	(267)	138	404	(152%)
7	Non-Integrated Area	4.0 L6	117	118	0	0%
8	Exchange Net	4.0 L3	(115)	(253)	(138)	120%
9	Total	4.0 L12	57,162	56,832	(331)	(1%)

Actual fiscal 2017 energy supplied was 331GWh (or 1 per cent) lower than the fiscal 2017 RRA Plan. Higher surplus sales which were needed for reservoir management were partially offset by higher purchases by Powerex due to BC Hydro system constraints which limited Powerex's opportunity to export for trade and higher deliveries from independent Power Producers (**IPPs**).

3.1.2 Sources of Supply Variance Explanations – Fiscal 2018

Table G-6 compares fiscal 2018 energy supply sources actuals (in GWh) against the fiscal 2018 RRA Plan, with variance explanations below the table.

Table G-6 Fiscal 2018 Sources of Supply

	(GWh)	Schedule Reference	F2018 RRA	F2018 Actual	F2018 Diff	F2018 % Diff
			1	2	3 = 2 - 1	4 = 3 / 1
1	Water Rentals	4.0 L1	47,219	47,926	707	1%
2	IPPs and Long-Term Commitments	4.0 L5	15,002	14,354	(648)	(4%)
3	Market Electricity Purchases	4.0 L8	747	150	(597)	(80%)
4	Natural Gas for Thermal Generation	4.0 L2	232	91	(141)	(61%)
5	Surplus Sales	4.0 L9	(5,556)	(5,072)	484	(9%)
6	Net Purchases (Sales) from Powerex	4.0 L10	(253)	(557)	(304)	120%
7	Non-Integrated Area	4.0 L6	119	115	(5)	(4%)
8	Exchange Net	4.0 L3	(323)	599	923	(285%)
9	Total	4.0 L12	57,187	57,606	419	1%

Actual fiscal 2018 energy supplied was 419 GWh (1 per cent) higher than the fiscal 2018 RRA Plan. Inflows to the system during fiscal 2018 were 98 per cent of average. The below average inflows were due to dry weather in the Peace region, partially offset by higher snowmelt contribution in the Columbia region, and resulted in fewer surplus sales during the year. Despite lower inflows, hydro generation was higher than forecast in fiscal 2018. This was due to fewer deliveries from IPPs, fewer domestic market purchases and higher net sales to Powerex due to greater market trading opportunities. In addition, higher net exchange volumes were largely driven from higher than planned generation related to the Canal Plant and Keenleyside coordination agreements.

3.2 Cost of Energy Variance Explanations

3.2.1 Cost of Energy Variance Explanations – Fiscal 2017

Table G-7 compares fiscal 2017 Cost of Energy actual amounts (in $millions) against the fiscal 2017 RRA Plan, with variance explanations below the table.

Table G-7 Fiscal 2017 Cost of Energy

		Schedule	F2017			
	($ million)	Reference	RRA	Actual	Diff	% Diff
			1	2	3 = 2 - 1	4 = 3 / 1
1	Water Rentals	4.0 L23+L32	386.7	387.0	0.4	0%
2	IPPs and Long-Term Commitments	4.0 L29	1,234.4	1,213.1	(21.3)	(2%)
3	Market Electricity Purchases	4.0 L34	8.6	3.4	(5.2)	(61%)
4	Natural Gas for Thermal Generation	4.0 L24	14.9	9.5	(5.4)	(36%)
5	Domestic Transmission - Other	4.0 L25	22.6	22.5	(0.1)	(1%)
6	Domestic Transmission - Export	4.0 L37	31.8	28.3	(3.5)	(11%)
7	Columbia River Treaty Related Agreements	4.0 L26	(23.1)	(23.3)	(0.2)	1%
8	Surplus Sales	4.0 L35	(118.1)	(132.8)	(14.6)	12%
9	Net Purchases (Sales) from Powerex	4.0 L36	(6.5)	2.3	8.8	(136%)
10	Non-Integrated Area	4.0 L30	24.6	25.0	0.4	1%
11	Gas & Other Transportation	4.0 L31	10.6	11.7	1.1	11%
12	Remissions and Other	4.0 L27	(37.3)	(41.3)	(4.0)	11%
13	Total	4.0 L39	1,549.3	1,505.5	(43.8)	(3%)

Actual fiscal 2017 Cost of Energy was $43.8 million (or 3 per cent) lower than the fiscal 2017 RRA Plan. This was primarily due to:

- Lower costs from IPPs largely due to delayed commercial operation dates for several projects; and
- Higher Surplus Sales as higher export volumes were needed to manage spill risk at Williston reservoir and maintain downstream Arrow reservoir levels. In addition, higher Mid-C prices during the summer also resulted in higher than planned surplus sales revenues during that period, which were partially offset by lower Surplus Sales later in the fiscal year due to lower inflows and softer prices.

Partially offset by:

- Higher Net Purchases from Powerex compared to planned net sales as a result of BC Hydro system constraints which limited Powerex's opportunity to export for trade.

3.2.2 Cost of Energy Variance Explanations – Fiscal 2018

Table G-8 compares fiscal 2018 Cost of Energy amounts (in $millions) against the fiscal 2018 RRA Plan, with variance explanations below the table.

Table G-8 Fiscal 2018 Cost of Energy

	($ million)	Schedule Reference	F2018 RRA	F2018 Actual	F2018 Diff	F2018 % Diff
			1	2	3 = 2 - 1	4 = 3 / 1
1	Water Rentals	4.0 L23+L32	356.8	361.6	4.8	1%
2	IPPs and Long-Term Commitments	4.0 L29	1,369.7	1,311.6	(58.1)	(4%)
3	Market Electricity Purchases	4.0 L34	30.2	3.7	(26.6)	(88%)
4	Natural Gas for Thermal Generation	4.0 L24	10.5	3.4	(7.1)	(68%)
5	Domestic Transmission - Other	4.0 L25	22.3	22.5	0.2	1%
6	Domestic Transmission - Export	4.0 L37	35.4	25.2	(10.2)	(29%)
7	Columbia River Treaty Related Agreements	4.0 L26	(10.4)	(40.6)	(30.2)	291%
8	Surplus Sales	4.0 L35	(150.4)	(139.4)	11.0	(7%)
9	Net Purchases (Sales) from Powerex	4.0 L36	(6.0)	(10.9)	(4.9)	83%
10	Non-Integrated Area	4.0 L30	27.4	26.5	(0.9)	(3%)
11	Gas & Other Transportation	4.0 L31	10.1	13.1	3.0	29%
12	Remissions and Other	4.0 L27	(37.8)	(38.0)	(0.1)	0%
13	Total	4.0 L39	1,657.8	1,538.7	(119.2)	(7%)

Actual fiscal 2018 actual Cost of Energy was $119.2 million (or 7 per cent) lower than the fiscal 2018 RRA Plan. This was primarily due to:

- Lower costs from IPPs, mainly driven by delayed commercial operation dates and terminated projects;
- Lower Market Electricity Purchases due to market purchases not being required to meet the domestic load requirements as supply from other sources was sufficient;

- Lower Natural Gas for Thermal Generation costs due to an outage at the Fort Nelson Generating Station which resulted in lower thermal generation;
- Lower domestic transmission charges as a result of lower Surplus Sales;
- Higher recoveries from water transactions associated with the Columbia River Treaty related agreements primarily due to more releases from storage as a result of strong market prices and dryer weather in the U.S.; and
- Higher Net Sales to Powerex due to greater market trading opportunities.

Partially offset by:

- Lower Surplus Sales primarily due to lower system inflows.

4 Operating Costs Variance Explanations (Chapter 5)

Chapter 5 of the Application addresses BC Hydro's Operating Costs.

This section compares gross operating costs and provisions actual amounts for fiscal 2017 and fiscal 2018 with the Plan amounts from the Previous Application.

4.1 Operating Costs Variance Explanations - Fiscal 2017

Table G-9 compares fiscal 2017 gross operating cost and provisions actual amounts against the fiscal 2017 RRA Plan, with variance explanations below the table.

Table G-9 Fiscal 2017 Operating Costs and Provisions Variances

	($ million)	Schedule Reference	F2017 RRA	F2017 Actual	F2017 Diff	F2017 % Diff
			1	2	3 = 2 - 1	4 = 3 / 1
1	Integrated Planning	5.0 L1	271.3	284.8	13.5	5%
2	Capital Infrastructure Project Delivery	5.0 L2	79.7	79.2	(0.5)	-1%
3	Operations	5.0 L3	206.1	204.2	(1.9)	-1%
4	Safety	5.0 L4	54.6	55.9	1.4	3%
5	Finance, Technology, Supply Chain	5.0 L5	263.3	253.8	(9.5)	-4%
6	People, Customer, Corporate Affairs	5.0 L6	124.3	115.2	(9.1)	-7%
7	Other	5.0 L7	(252.7)	(256.6)	(3.9)	2%
8	F17-F19 RRA Compliance Filing Adjustment	5.0 L8	10.1	0.0	(10.1)	-100%
9	**Base Operating Costs**	5.0 L9	756.6	736.6	(20.0)	-3%
10	IFRS Ineligible Capitalized Overhead	5.0 L10	102.9	102.9	0.0	0%
11	Independent Power Producers Capital Leases	5.0 L11	28.2	28.2	0.0	0%
12	Waneta 2/3	5.0 L12	0.0	0.0	0.0	0%
13	Customer Crisis Fund	5.0 L13	0.0	0.0	0.0	0%
14	**Net Operating Costs**	5.0 L15	887.7	867.6	(20.0)	-2%
15	Operating Costs Deferral Account Additions	5.0 L52	0.0	(9.0)	(9.0)	0%
16	Operating Costs Regulatory Account Additions	5.0 L63	231.3	242.9	11.6	5%
17	**Total Gross Operating Costs**	L14+L15+L16	1,119.0	1,101.5	(17.4)	-2%
18	Provisions before Regulatory Accounts	5.0 L77	64.7	83.0	18.3	28%
19	Deferral Account Additions - Provisions	5.0 L102	0.0	0.0	0.0	0%
20	Regulatory Account Additions - Provisions	5.0 L109	1.2	(19.5)	(20.7)	-1672%
21	Total Gross Provisions and Other	5.0 L110	66.0	63.6	(2.4)	-4%
22	**Total Gross Operating Costs and Provisions and Other**	L17+L21	1,185.0	1,165.1	(19.9)	-2%

As shown in Table G-9, overall, actual fiscal 2017 actual gross operating costs and provisions and other were $19.9 million (or 2 per cent) lower than the fiscal 2017 RRA Plan. Of this amount, $18.1 million (the sum of lines 15, 16, and 20) related to variances in transfers to regulatory accounts, and $1.8 million (the sum of lines 14 and 18) related to variances unrelated to regulatory account transfers.

Variances related to the regulatory transfers of $18.1 million were primarily due to the following:

- Decrease in the Demand-Side Management Regulatory Account (within line 16) of $16.3 million due to delayed project completions and project cancellations in the commercial and industrial sectors;
- Decrease in the Environmental Provisions Regulatory Account (within line 20) of $28.0 million resulting from a decrease to the Rock Bay provision of $16.8 million due to a change in the project cost estimate. In addition, there was a decrease in the Polychlorinated Biphenyl provision of $9.8 million and the Asbestos Remediation provision of $1.4 million mainly due to an increase in the discount rate (resulting in a decrease in the present value of the forecast remediation expenditures); and
- Decrease in the Non-Heritage Deferral Account (within line 15) of $8.9 million resulting from a decrease of $9.1 million due to delayed commercial operation dates for two IPPs projects, and an increase of $0.2 million due to a deferral of Burrard costs pursuant to Order No. G-48-14.

Partially offset by:

- Increase in the Storm Restoration Costs Regulatory Account (within line 16) of $18.6 million due to a harsh winter which led to higher than planned expenditures for storm restoration;
- Increase in the Post Employment Benefit Current Pension Costs Regulatory Account (within line 16) of $10.1 million pursuant to Order No. G-47-18, Directive 18, which directed BC Hydro to use the discount rate in effect at the time the forecast was prepared to calculate current service costs; and
- All other regulatory account variances (primarily within line 20), totalling an increase of $6.4 million.

The variance of $1.8 million unrelated to regulatory accounts transfers are primarily due to:

- Lower than plan costs (within line 9) of $10.1 million due to the fiscal 2017 adjustment being made prospectively in fiscal 2018 pursuant to BCUC Order No. G-47-18, Directive 18, which directed BC Hydro to use the discount rate in effect at the time the forecast was prepared to calculate current service costs;
- Lower than plan costs (within line 9) of $10.0 million primarily due to lower than planned labour costs, partially offset by higher capital project dispute resolution costs. Individual variances within the business groups (lines 1 through 7) include reallocation of costs attributed to a reorganization which had no impact to the overall base operating cost variance (line 9); and
- All other variances (within line 18), totalling a decrease of $5.5 million.

Partially offset by:

- Higher than plan capital expenditure write-offs and capital asset retirements (within line 18) of $23.8 million, primarily comprised of $15.0 million in unplanned capital expenditure write-offs relating to projects that were cancelled in fiscal 2017 and $6.4 million relating to two unanticipated capital asset retirements.

4.2 Operating Costs Variance Explanations - Fiscal 2018

Table G-10 compares fiscal 2018 gross operating cost and provisions actual amounts against the fiscal 2018 RRA Plan, with variance explanations below the table.

Table G-10 Fiscal 2018 Operating Costs and Provisions Variances

	($ million)	Schedule Reference	F2018 RRA	F2018 Actual	F2018 Diff	F2018 % Diff
			1	2	3 = 2 - 1	4 = 3 / 1
1	Integrated Planning	5.0 L1	269.4	283.8	14.4	5%
2	Capital Infrastructure Project Delivery	5.0 L2	81.1	79.9	(1.2)	-2%
3	Operations	5.0 L3	208.2	206.7	(1.5)	-1%
4	Safety	5.0 L4	54.6	53.3	(1.3)	-2%
5	Finance, Technology, Supply Chain	5.0 L5	264.4	246.7	(17.7)	-7%
6	People, Customer, Corporate Affairs	5.0 L6	121.8	116.8	(5.1)	-4%
7	Other	5.0 L7	(252.2)	(244.0)	8.2	-3%
8	F17-F19 RRA Compliance Filing Adjustment	5.0 L8	10.2	0.0	(10.2)	-100%
9	**Base Operating Costs**	5.0 L9	757.5	743.1	(14.4)	-2%
10	IFRS Ineligible Capitalized Overhead	5.0 L10	125.3	125.3	0.0	0%
11	Independent Power Producers Capital Leases	5.0 L11	63.6	63.6	0.0	0%
12	Waneta 2/3	5.0 L12	0.0	0.0	0.0	0%
13	Customer Crisis Fund	5.0 L13	0.0	0.0	0.0	0%
14	**Net Operating Costs**	5.0 L15	946.3	931.9	(14.4)	-2%
15	Operating Costs Deferral Account Additions	5.0 L52	0.0	(35.3)	(35.3)	0%
16	Operating Costs Regulatory Account Additions	5.0 L63	212.7	179.8	(32.9)	-15%
17	**Total Gross Operating Costs**	L14+L15+L16	1,159.0	1,076.4	(82.6)	-7%
18	Provisions before Regulatory Accounts	5.0 L77	71.0	115.2	44.2	62%
19	Deferral Account Additions - Provisions	5.0 L102	0.0	1.6	1.6	0%
20	Regulatory Account Additions - Provisions	5.0 L109	(10.0)	35.4	45.4	-454%
21	Total Gross Provisions and Other	5.0 L110	61.0	152.3	91.2	150%
22	**Total Gross Operating Costs and Provisions and Other**	L17+L21	1,220.0	1,228.7	8.7	1%

As shown in Table G-10, overall, actual fiscal 2018 gross operating costs and provisions and other were $8.7 million (1 per cent) higher than fiscal 2018 RRA Plan. Of this amount, $29.8 million (the sum of lines 14 and 18) was variances unrelated to regulatory account transfers, which was partially offset by $21.1 million (the sum of lines 15, 16, 19 and 20) in variances related to regulatory account transfers.

Variances of $29.8 million unrelated to regulatory accounts transfers were primarily due to:

- Higher capital expenditure write-offs and capital asset retirements (within line 18) of $30.9 million primarily due to $13.6 million from the cancellation of the construction of the new Terrace to Kitimat Transmission line, with the remaining $17.3 million variance due to the reduction in scope of various projects;
- Higher than plan costs (within line 9) of $10.1 million due to fiscal 2017 actual adjustment being made prospectively in fiscal 2018 pursuant to BCUC Order No. G-47-18, Directive 18, which directed BC Hydro to use the discount rate in effect at the time the forecast was prepared to calculate current service costs. Individual variances within the business groups (lines 1 through 7) include reallocation of costs attributed to a reorganization which had no impact to the overall base operating cost variance (line 9);
- Higher litigation costs (within line 18) of $6.9 million related to a capital project;
- $4.0 million from termination of an Electricity Purchase Agreement (within line 18); and
- All other variances (within line 18), totalling an increase of $2.4 million.

Partially offset by:

- Lower costs (within line 9) of $24.5 million primarily due to lower than planned expenditures on external services.

Variances related to regulatory account transfers of $21.1 million were primarily due to:

- A decrease in the Non-Heritage Deferral Account (within lines 15 and 19) of $34.0 million resulting primarily from delayed commercial operation dates for two IPP projects;
- A decrease in the Demand-Side Management Regulatory Account (within line 16) of $36.9 million primarily due to delayed project completions and cancellations;
- A decrease in the Post Employment Benefit Current Pension Costs Regulatory Account (within line 16) of $10.1 million pursuant to BCUC Order No. G-47-18, Directive 18, which directed BC Hydro to use the discount rate in effect at the time the forecast was prepared to calculate current service costs; and
- All other regulatory account variances (within lines 15,16, and 20) totalled a net decrease of $4.8 million.

Partially offset by:

- An increase in the Dismantling Costs Regulatory Account (within line 20) of $31.7 million primarily due to work performed on the unplanned Salmon River Diversion Decommissioning Project which was originally planned to be upgraded, and dismantling work on projects from prior years that was delayed to this fiscal year;
- An increase in the Real Property Sales Regulatory Account (within line 20) of $16.8 million due to lower than planned gains from property sales; and
- An increase in the Storm Restoration Costs Regulatory Account (within line 16) of $16.2 million due to a series of wildfires in the interior of British Columbia, heavy snowfall in Vancouver Island and the Lower Mainland, and freezing rain

and ice in the Fraser Valley during the winter which led to higher than planned expenditures for storm restoration.

5 Capital Expenditures and Capital Additions Variance Explanations (Chapter 6)

Chapter 6 of the Application addresses BC Hydro's capital expenditures and capital additions for the test period. This section compares capital expenditure and capital addition actual amounts for fiscal 2017 and fiscal 2018 with the Plan amounts from the Previous Application.

Generally, explanations are provided where variances between actual and planned amounts are greater than 10 per cent, with a minimum variance threshold of $10 million, for the main asset categories provided in the following tables. Variances are provided for each main asset category in the tables below. The amounts presented in the tables in this section may not add due to rounding.

5.1 Overall Capital Expenditures and Additions Variance Explanations - Fiscal 2017 and Fiscal 2018

On an annual basis, BC Hydro actively manages over 900 projects and programs in various project phases and of various sizes. Capital expenditures and capital additions variances are mainly due to project progression and changes in project timing. Other factors include changes in scope to meet business requirements or cost changes due to market conditions or other factors. In addition, capital projects frequently extend over several years before completion and any variances from plan in a particular year can be offset by project expenditures and additions shifting to a subsequent year. While year-over-year capital project cash flows may vary from annual plan amounts, overall BC Hydro is delivering its capital plan on time and on budget. This is discussed further in Chapter 6, sections 6.1 and 6.2.

Table G-11 and Table G-12 compare fiscal 2017 and fiscal 2018 capital expenditures and capital additions actual amounts against the fiscal 2017 and fiscal 2018 RRA Plan by main asset category, with variance explanations below the tables.

Table G-11 BC Hydro Fiscal 2017 and Fiscal 2018 RRA Plan and Actual Capital Expenditures

($ millions)	F2017				F2018			
	RRA	Actual	Variance	% Variance	RRA	Actual	Variance	% Variance
	1	2	3=2-1	4=3/1	1	2	3=2-1	4=3/1
Generation	550.0	584.8	34.8	6%	536.4	544.1	7.7	1%
Site C Project	742.5	662.7	(79.8)	-11%	716.5	704.9	(11.6)	-2%
Transmission & Distribution	927.3	966.0	38.7	4%	941.8	1,021.4	79.6	8%
Business Support								
Technology	83.9	76.5	(7.4)	-9%	93.4	71.2	(22.2)	-24%
Properties	95.7	86.6	(9.1)	-10%	75.1	63.5	(11.6)	-15%
Fleet / Other	204.7	58.9	(145.8)	-71%	48.6	59.6	11.0	23%
Total Gross	2,604.1	2,435.5	(168.6)	-6%	2,411.8	2,464.7	52.9	2%
Less: Contribution in Aid	(86.4)	(138.4)	(52.0)	60%	(100.2)	(156.2)	(56.0)	56%
Total	2,517.7	2,297.1	(220.6)	-9%	2,311.6	2,308.5	(3.1)	0%

In fiscal 2017, actual capital expenditures were $168.6 million (or 6 per cent) below the fiscal 2017 RRA Plan, excluding contribution in aid, primarily due to:

- Under plan expenditures of $145.8 million in the Fleet/Other category primarily due to two planned land purchases not completed as a result of schedule delays and due to requirements for additional planning work; and
- Delayed expenditures of $79.8 million on the Site C Project due to shifting certain activities to future years, as discussed further below.

The above variances were partially offset by:

- Generation expenditures above plan by $34.8 million primarily due to the earlier than planned progression of the W.A.C. Bennett Dam Rip-Rap Upgrade project, which was ahead of schedule and under budget; and
- Transmission and Distribution expenditures above plan by $38.7 million primarily due to higher than planned expenditures in system expansion and

improvement related to performance and safety issues, and also pole asset replacements.

Contributions in Aid were $52 million (or 60 per cent) above the fiscal 2017 RRA Plan primarily due to the higher than planned Customer Driven Distribution capital expenditures.

In fiscal 2018, actual capital expenditures were $52.9 million (or two per cent) above the fiscal 2018 RRA Plan, primarily due to:

- Higher than planned expenditures of $86 million on the Interior to Lower Mainland Transmission Line Project due to an arbitrator decision on a contractor claim, which increased the cost of the project.

This variance was partially offset by:

- Lower than planned Technology expenditures of $22 million primarily due to the Supply Chain Application Project, which was delayed pending regulatory approval.

Contributions in Aid were $56 million (or 56 per cent) above the fiscal 2018 RRA Plan primarily due to the higher than planned Customer Driven Distribution capital expenditures.

Additional capital expenditure variance details are provided for each asset category further below in this section.

Table G-12 BC Hydro Fiscal 2017 and Fiscal 2018 RRA Plan and Actual Capital Additions

($ millions)	F2017				F2018			
	RRA	Actual	Variance	% Variance	RRA	Actual	Variance	% Variance
	1	2	3=2-1	4=3/1	1	2	3=2-1	4=3/1
Generation	513.0	342.7	(170.3)	-33%	387.1	407.2	20.1	5%
Site C Project	-	-	-	0%	-	-	-	0%
Transmission & Distribution	864.3	904.0	39.6	5%	839.0	853.1	14.1	2%
Business Support								
Technology	81.6	81.6	-	0%	91.1	97.2	6.1	7%
Properties	68.3	54.8	(13.5)	-20%	118.2	126.9	8.7	7%
Fleet / Other	210.3	85.6	(124.7)	-59%	54.5	59.4	4.9	9%
Total Gross	**1,737.5**	**1,468.7**	**(268.9)**	**-15%**	**1,489.9**	**1,543.8**	**53.9**	**4%**
Less: Contribution in Aid	(90.1)	(103.7)	(13.6)	15%	(88.0)	(129.6)	(41.6)	47%
Total	**1,647.4**	**1,365.0**	**(282.5)**	**-17%**	**1,401.9**	**1,414.2**	**12.3**	**1%**

Planned capital additions are based on the primary asset category of the planned project or program; however, the actual capital additions are based on the actual assets constructed. For example, a project which is considered primarily a Transmission project for planning purposes may include the construction of assets that are Distribution or Technology assets. While the total cost of the project would be reflected in Transmission category for planning purposes, the capital addition actuals are based on the actual assets constructed, and additions may appear in Transmission, Distribution or Technology capital additions. A portion of the capital addition variances for the various asset categories may be due to this difference.

In fiscal 2017, actual capital additions were $268.9 million below the fiscal 2017 RRA Plan, primarily due to:

- Delayed additions for planned land purchases of approximately $110 million as noted above in the capital expenditures explanations; and
- Delayed additions of $118 million on the Ruskin Dam Safety and Powerhouse Upgrade project due to schedule delays which shifted placing certain assets in-service to future years.

Contributions in Aid were $14 million (or 15 per cent) above the fiscal 2017 RRA Plan primarily due to the higher than planned Customer Driven Distribution capital additions.

In fiscal 2018, actual capital additions were $53.9 million above the fiscal 2018 RRA Plan, primarily due to:

- Higher than planned additions on the Ruskin Dam Safety and Powerhouse Upgrade project of $74 million due to shifting capital additions from fiscal 2017 to fiscal 2018.

The above higher than planned additions were partially offset by:

- Lower than planned additions on the Bridge River 1 Replace Transformers T1 and T2 project of $33 million. The project was placed in-service at the end of fiscal 2018; however, the capital additions were not recognized until early fiscal 2019.

Contributions in Aid were $42 million (or 47 per cent) above the fiscal 2018 RRA Plan primarily due to the higher than planned Customer Driven Distribution capital additions.

Additional information on capital additions variance for each asset category is provided further below in this section.

5.2 Generation Capital Expenditures and Additions Variance Explanations - Fiscal 2017 and Fiscal 2018

Table G-13 and Table G-14 compare fiscal 2017 and fiscal 2018 capital expenditures and capital additions actual amounts against the fiscal 2017 and fiscal 2018 RRA Plan for the Generation asset category. Sections 5.2.1 to 5.2.4 provide comparisons by sub-category for Generation. Results exclude the Site C Project which is provided separately in section 5.6.

Table G-13 Fiscal 2017 and Fiscal 2018 Generation Plan and Actual Capital Expenditures (excluding Site C Project)

($ millions)	F2017				F2018			
	RRA	Actual	Variance	% Variance	RRA	Actual	Variance	% Variance
	1	2	3=2-1	4=3/1	1	2	3=2-1	4=3/1
Hydroelectric Generation								
Growth	20.0	21.2	1.2	6%	2.4	10.2	7.8	325%
Redevelopment / Rehabilitation	335.2	344.1	9.0	3%	277.0	288.7	11.7	4%
Dam Safety	57.0	89.2	32.2	56%	94.7	71.0	(23.7)	-25%
Sustaining - Other	149.8	118.2	(31.6)	-21%	205.2	156.0	(49.2)	-24%
Total Hydroelectric Generation	561.9	572.7	10.8	2%	579.3	525.9	(53.4)	-9%
Total Non Integrated Areas	7.7	5.7	(2.0)	-26%	7.2	8.3	1.1	15%
Total Thermal Generation	8.4	6.4	(2.0)	-24%	8.9	9.9	1.0	11%
Less: Portfolio Risk Adjustment	(28.0)	-	28.0		(59.0)	-	59.0	
Total Gross	550.0	584.8	34.8	6%	536.4	544.1	7.7	1%
Less: Contribution in Aid	-	0.3	0.3		-	-	-	
Total	550.0	585.1	35.1	6%	536.4	544.1	7.7	1%

Table G-14 Fiscal 2017 and Fiscal 2018 Generation Plan and Actual Capital Additions (excluding Site C Project)

($ millions)	F2017				F2018			
	RRA	Actual	Variance	% Variance	RRA	Actual	Variance	% Variance
	1	2	3=2-1	4=3/1	1	2	3=2-1	4=3/1
Hydroelectric Generation								
Growth	26.6	24.2	(2.4)	-9%	0.9	9.6	8.7	967%
Redevelopment / Rehabilitation	304.0	183.1	(120.9)	-40%	184.4	258.8	74.4	40%
Dam Safety	57.4	27.7	(29.7)	-52%	66.9	80.8	13.9	21%
Sustaining - Other	101.1	85.0	(16.1)	-16%	124.6	52.8	(71.8)	-58%
Total Hydroelectric Generation	489.1	320.0	(169.1)	-35%	376.8	402.0	25.2	7%
Total Non Integrated Areas	8.3	8.2	(0.1)	-1%	6.9	4.1	(2.8)	-41%
Total Thermal Generation	15.6	14.5	(1.1)	-7%	3.4	1.1	(2.3)	-68%
Less: Portfolio Risk Adjustment	-	-	-		-	-	-	
Total Gross	513.0	342.7	(170.3)	-33%	387.1	407.2	20.1	5%
Less: Contribution in Aid	(0.3)	(2.0)	(1.7)	567%	-	-	-	
Total	512.7	340.7	(172.0)	-34%	387.1	407.2	20.1	5%

5.2.1 Growth Capital Expenditures and Additions

Capital expenditure variances

Fiscal 2017 capital expenditures were comparable to plan.

Fiscal 2018 capital expenditures were $7.8 million above fiscal 2018 RRA Plan primarily due to the Upper Columbia Capacity Additions at Mica Units 5 and 6 project spending $5.0 million more in fiscal 2018 than planned to complete deficiency work, and the Revelstoke Install Unit 6 project spending $2 million more than planned in fiscal 2018 due to increased costs to complete the environmental assessment process.

Capital addition variances

Fiscal 2017 capital additions were comparable to the fiscal 2017 RRA Plan.

Fiscal 2018 capital additions were $8.7 million above the fiscal 2018 RRA Plan primarily due to the capital expenditure increase as noted above.

5.2.2 Redevelopment/Rehabilitation Capital Expenditures and Additions

Capital expenditure variances

Fiscal 2017 and fiscal 2018 capital expenditures were comparable to the fiscal 2017 and fiscal 2018 RRA Plan.

Capital addition variances

Fiscal 2017 capital additions were $120.9 million (40 per cent) below the fiscal 2017 RRA Plan primarily due to the Ruskin Dam Safety and Powerhouse Upgrade project being $117.8 million under plan as a result of construction delays, which shifted activities to future years.

Fiscal 2018 capital additions were $74.4 million (40 per cent) above the fiscal 2018 RRA Plan due to the Ruskin Dam Safety and Powerhouse Upgrade project Unit 2 in-service date moving from fiscal 2017 to fiscal 2018 as noted above.

5.2.3 Dam Safety Capital Expenditures and Additions

Capital expenditure variances

Fiscal 2017 capital expenditures were $32.2 million (56 per cent) above the fiscal 2017 RRA Plan primarily due to the W.A.C. Bennett Dam Rip Rap Upgrade project being $37.2 million above plan as a result of construction progressing ahead of schedule.

Fiscal 2018 capital expenditures were $23.7 million (25 per cent) below the fiscal 2018 RRA Plan primarily due to:

- Bridge River 1 Improve Slope Drainage project – implementation of the project was delayed as risk mitigation alternatives were explored, which resulted in expenditures being $13.2 million below plan;
- GMS Spillway Gate Upgrade Project – the award of a key contract was delayed which resulted in expenditures being $5.9 million below plan; and
- W.A.C. Bennett Dam Upgrade Rip Rap – some project expenditures were shifted to fiscal 2017, as described above.

Capital addition variances

Fiscal 2017 capital additions were $29.7 million (52 per cent) below the fiscal 2017 RRA Plan primarily due to:

- Jordan River Mitigate Diversion Dam Seismic Risks project was $11.7 million below plan due to property purchases incurred in fiscal 2017 that were not recognized as capital additions until fiscal 2018;
- Bridge River 1 Install Penstock Leak Detection and Protection project was $6.0 million below plan due to delays in installing equipment;
- GMS WAC Bennett Dam Core Upgrade was $3.2 million under plan due to construction delays which moved the in-service date to fiscal 2018; and
- Hugh Keenleyside Spillway Reliability Gate Upgrade was $3.4 million under plan due to lower than expected costs.

Fiscal 2018 capital additions were $13.9 million (21 per cent) above the fiscal 2018 RRA Plan, primarily due to the W.A.C. Bennett Dam Rip Rap Upgrade project being partially put into service ahead of schedule.

5.2.4 Sustaining - Other - Capital Expenditure and Additions Variances

Capital expenditure variances

Fiscal 2017 capital expenditures were $31.6 million (21 per cent) below the fiscal 2017 RRA Plan due to a large number of projects having small variances as a result of scheduling, scope or cost changes.

Fiscal 2018 capital expenditures were $49.2 million (24 per cent) below the fiscal 2018 RRA Plan primarily due to:

- Bridge River 2 Upgrade Units 5 and 6 project was $16.9 million below plan due to delays in completion of the Unit 5 caused by the supplier's quality issues in manufacturing and installation of the generator;
- Kootenay Canal Upgrade Powerhouse Crane project was $13 million below plan as a result of a scope reduction of certain runway deficiency work which was deemed no longer necessary; and
- Mica Upgrade 600 V Circuit Breakers project was $8 million below plan as a result of combining the Mica Essential Bus and Diesel Generator project with this project due to interdependencies.

Capital addition variances

Fiscal 2017 capital additions were $16.1 million (16 per cent) below the fiscal 2017 RRA Plan due to the Puntledge Improve Water Level Gauges and Public Safety Warning System project being $7.0 million below plan as a result of the in-service date delay to fiscal 2018. The remaining variances were due to a number of projects with smaller variances.

Fiscal 2018 capital additions were $71.8 million (58 per cent) below the fiscal 2018 RRA Plan, primarily due to:

- Bridge River 1 Replace Transformers T1 and T2 was $33.2 million below plan due to the capital expenditures not being converted to capital additions until after the fiscal year, although the project was put into service before year-end;
- Wahleach Reduce Fire Risk - Phase 2 project was $7.5 million below plan as the in-service date for the project was delayed to fiscal 2019 to complete the engineering specifications;
- G.M. Shrum G1 to 10 Control System Upgrade project was $7.9 million below plan because the G9 unit in-service date was delayed to fiscal 2019 due to outage scheduling and sequencing; and
- Ladore Install Powerhouse and Tailrace Crane project was $8.7 million below plan as the in-service date was delayed to fiscal 2019 as a longer lead time was required for crane manufacturing.

5.2.5 Non-Integrated Areas and Diesel and Thermal Generation

Fiscal 2017 and fiscal 2018 capital expenditures and additions were comparable to the fiscal 2017 and fiscal 2018 RRA Plan.

5.3 Transmission Capital Expenditures and Additions Variance Explanations - Fiscal 2017 and Fiscal 2018

Table G-15 and Table G-16 compare the fiscal 2017 and fiscal 2018 capital expenditures and capital additions actuals against the fiscal 2017 and fiscal 2018 RRA Plan for the Transmission asset category. Sections 5.2.1 to 5.2.4 provide comparisons by sub-category for Transmission.

Table G-15 Fiscal 2017 and Fiscal 2018 Transmission Plan and Actual Capital Expenditures

($ millions)	F2017				F2018			
	RRA	Actual	Variance	% Variance	RRA	Actual	Variance	% Variance
	1	2	3=2-1	4=3/1	1	2	3=2-1	4=3/1
Transmission Growth								
Regional System Reinforcement	92.2	120.8	28.6	31%	68.4	89.2	20.8	30%
Bulk System Reinforcement	30.1	20.9	(9.2)	-31%	7.2	115.2	108.0	1510%
Station Expansion & Modification	88.8	73.1	(15.7)	-18%	74.0	55.8	(18.2)	-25%
Feeder Positions / Section Additions	1.1	1.0	(0.1)	-6%	1.2	0.7	(0.5)	-39%
Generator Interconnections	30.3	17.0	(13.3)	-44%	41.5	7.1	(34.4)	-83%
Transmission Load Interconnection	19.5	14.5	(5.0)	-26%	29.7	12.4	(17.3)	-58%
Total Growth	262.1	247.3	(14.7)	-6%	221.9	280.4	58.5	26%
Transmission Sustain - Stations								
Circuit Breakers	28.2	34.7	6.5	23%	18.6	34.8	16.2	87%
Other Power Equipment	48.5	77.5	29.0	60%	80.8	54.4	(26.4)	-33%
Protection and Control	11.6	9.4	(2.2)	-19%	22.3	7.4	(14.9)	-67%
Stations Auxiliary Equipment	30.6	26.9	(3.7)	-12%	20.6	18.6	(2.0)	-10%
Stations Risk Mitigation	6.5	4.9	(1.6)	-24%	8.3	2.0	(6.3)	-76%
Telecommunications	7.7	5.6	(2.1)	-27%	14.1	6.7	(7.4)	-53%
Total Sustain - Stations	133.1	159.0	25.9	19%	164.7	124.0	(40.8)	-25%
Transmission Sustain - Lines								
Cable Sustainment	12.0	8.2	(3.8)	-32%	30.0	28.0	(2.0)	-7%
O/H Lines Life Extension	72.4	63.3	(9.0)	-12%	94.6	27.4	(67.3)	-71%
O/H Lines Performance Improvement	4.1	6.8	2.7	65%	3.8	3.7	(0.1)	-3%
O/H Lines Risk Mitigation	17.5	10.1	(7.4)	-42%	15.4	20.9	5.5	36%
ROW Sustainment	10.2	11.5	1.3	12%	10.4	9.8	(0.5)	-5%
Third Party Requested Transmission Line Relocations	6.2	9.1	2.9	48%	7.5	4.6	(2.9)	-39%
Total Sustain - Lines	122.3	109.0	(13.3)	-11%	161.7	94.4	(67.2)	-42%
Total Gross	**517.6**	**515.4**	**(2.2)**	0%	**548.3**	**498.9**	**(49.5)**	-9%
Less: Contribution in Aid	(9.8)	(15.8)	(6.0)	61%	(21.8)	(15.6)	6.2	-28%
Total	**507.8**	**499.6**	**(8.2)**	-2%	**526.5**	**483.3**	**(43.3)**	-8%

Table G-16 Fiscal 2017 and Fiscal 2018 RRA Plan and Actual Transmission Capital Additions

($ millions)	F2017				F2018			
	RRA	Actual	Variance	% Variance	RRA	Actual	Variance	% Variance
	1	2	3=2-1	4=3/1	1	2	3=2-1	4=3/1
Transmission Growth								
Regional System Reinforcement	117.9	146.3	28.4	24%	9.7	13.2	3.5	36%
Bulk System Reinforcement	18.2	11.4	(6.8)	-37%	26.4	7.0	(19.4)	-73%
Station Expansion & Modification	37.7	35.5	(2.2)	-6%	149.6	125.8	(23.8)	-16%
Feeder Positions / Section Additions	2.0	1.9	(0.1)	-4%	-	0.1	0.1	
Generator Interconnections	55.7	56.3	0.5	1%	13.8	12.7	(1.1)	-8%
Transmission Load Interconnection	5.7	4.5	(1.2)	-21%	23.4	18.1	(5.2)	-22%
Total Growth	237.2	255.8	18.6	8%	222.9	176.9	(45.9)	-21%
Transmission Sustain - Stations								
Circuit Breakers	56.4	95.9	39.5	70%	17.6	19.9	2.3	13%
Other Power Equipment	41.4	36.6	(4.8)	-11%	36.8	80.2	43.4	118%
Protection and Control	13.0	16.0	3.0	23%	20.1	7.3	(12.8)	-64%
Stations Auxiliary Equipment	29.0	13.5	(15.5)	-53%	23.5	23.9	0.4	2%
Stations Risk Mitigation	6.7	7.8	1.1	16%	7.9	6.2	(1.7)	-21%
Telecommunications	7.8	4.4	(3.4)	-43%	11.9	5.6	(6.3)	-53%
Total Sustain - Stations	154.3	174.2	19.9	13%	117.9	143.1	25.3	21%
Transmission Sustain - Lines								
Cable Sustainment	4.9	1.7	(3.3)	-67%	4.2	2.0	(2.2)	-53%
O/H Lines Life Extension	55.4	6.4	(49.0)	-88%	60.7	50.4	(10.3)	-17%
O/H Lines Performance Improvement	4.4	1.4	(3.0)	-69%	3.9	6.2	2.3	60%
O/H Lines Risk Mitigation	19.8	24.7	4.9	25%	15.8	12.5	(3.3)	-21%
ROW Sustainment	10.7	9.2	(1.6)	-15%	10.4	12.3	1.9	19%
Third Party Requested Transmission Line Relocations	5.5	9.6	4.1	74%	4.0	4.2	0.2	5%
Total Sustain - Lines	100.8	52.9	(47.9)	-48%	99.0	87.6	(11.4)	-11%
Total Gross	**492.3**	**482.9**	**(9.4)**	**-2%**	**439.7**	**407.6**	**(32.0)**	**-7%**
Less: Contribution in Aid	(13.8)	(22.0)	(8.2)	59%	(9.7)	(16.6)	(6.9)	71%
Total	**478.5**	**460.9**	**(17.6)**	**-4%**	**430.0**	**391.0**	**(38.9)**	**-9%**

In the Transmission tables above ‘Generator Interconnections’ was formerly known as ‘Transmission IPPs’, ‘Transmission Load Interconnections’ was formerly known as ‘Customer Requested Projects’ and ‘Third Party Requested Transmission Line Relocations’ was formerly known as ‘OH/UG Relocations’. The composition of the renamed asset classifications has not changed.

5.3.1 Transmission Growth

5.3.1.1 Regional System Reinforcement

Capital expenditure variances

Fiscal 2017 capital expenditures were $28.6 million (31 per cent) above the fiscal 2017 RRA Plan primarily due to the fiscal 2017 RRA Plan amounts for a land purchase being included in Business Support - Other, while the actual expenditures are reported as Transmission as the land purchase relates to a future substation development.

Fiscal 2018 capital expenditures were $20.8 million (30 per cent) above the fiscal 2018 RRA Plan due to the Kamloops Substation project being above plan by $7.7 million due to design specification changes and increased costs from higher than expected market prices for equipment and materials. In addition, the Peace Region Electric Supply project was $8.7 million over plan due to advancement of definition phase activities from later years into fiscal 2018.

Capital addition variances

Fiscal 2017 capital additions were $28.4 million (24 per cent) above the fiscal 2017 RRA Plan due to the land purchase noted above.

Fiscal 2018 capital additions were comparable to the fiscal 2018 RRA Plan.

5.3.1.2 Bulk System Reinforcement

Capital expenditure variances

Fiscal 2017 capital expenditures were comparable to the fiscal 2017 RRA Plan.

Fiscal 2018 capital expenditures were $108 million above the fiscal 2018 RRA Plan due to unplanned expenditures of approximately $86 million on the Interior to Lower Mainland Transmission Line project due to an arbitrator decision on a contractor claim which increased the costs to the project.

Capital addition variances

Fiscal 2017 capital additions were comparable to the fiscal 2017 RRA Plan.

Fiscal 2018 capital additions were $19.4 million (73 per cent) below the fiscal 2018 RRA Plan primarily due to the Peace Region Load Shedding Remedial

Action Scheme (**RAS**) Project. The project was in service before year-end but the capital expenditures were not recognized as capital additions until after the fiscal year-end.

5.3.1.3 Station Expansion and Modification

Capital expenditure variances

Fiscal 2017 capital expenditures were $15.7 million (18 per cent) below the fiscal 2017 RRA Plan primarily due to a delay in land acquisition to review the project scope and a number of projects with small variances .

Fiscal 2018 capital expenditures were $18.2 million (25 per cent) below the fiscal 2018 RRA Plan primarily due to:

- Westbank Substation Upgrade project was $10 million under plan as the Identification Phase was deferred to fiscal 2019 pending a decision on the preferred alternative for the West Kelowna Transmission Project. The scope of this project is dependent on the alternative that will be selected for the West Kelowna Transmission Project, which is also described in Appendix J; and
- Capilano Substation 25 kV Conversion project was $5.8 million under plan due to longer than anticipated Identification and Definition phases of the project, to address required engineering and geotechnical studies.

Capital addition variances

Fiscal 2017 capital additions were comparable to the fiscal 2017 RRA Plan.

Fiscal 2018 capital additions were $23.8 million (16 per cent) below the fiscal 2018 RRA Plan, primarily due to the Campbell River Substation Capacity Upgrade Project which was $22.9 million under plan. During project Implementation, it was identified that ground conditions were inadequate to address seismic risks during site construction, therefore requiring additional planning and construction time and extending the project's in-service date to fiscal 2019.

5.3.1.4 Feeder Position/Section Additions

Fiscal 2017 and fiscal 2018 capital expenditures and additions were comparable to the fiscal 2017 and fiscal 2018 RRA Plans.

5.3.1.5 Generator Interconnections and Transmission Load Interconnections

These capital expenditures and additions are third-party driven and, as a result, the timing and scope of these projects are highly uncertain. BC Hydro only includes projects with a high probability of proceeding in its capital forecasts. Variances from forecast are due to changes in scope and timing of planned projects as well as the addition of new projects.

5.3.2 Transmission Sustain – Stations

5.3.2.1 Circuit Breakers

Capital expenditure variances

Fiscal 2017 capital expenditures were comparable to the fiscal 2017 RRA Plan. Fiscal 2018 actual capital expenditures were $16.2 million (87 per cent) above the fiscal 2018 RRA Plan due to the addition of the Barnard 60kV Circuit Breaker and Relay Building Replacement project and advancing the 60kV Circuit Breaker Replacement program to manage system risks.

Capital addition variances

Fiscal 2017 capital additions were $39.5 million (70 per cent) above the fiscal 2017 RRA Plan, primarily due to the 230 kV Airblast Circuit Breaker Replacements program and the 60/138 kV Circuit Breaker Replacements program having schedule delays which resulted in $26.6 million of additions shifting from fiscal 2016 to fiscal 2017.

Fiscal 2018 capital additions were comparable to the fiscal 2018 RRA Plan.

5.3.2.2 Other Power Equipment

Capital expenditure variances

Fiscal 2017 capital expenditures were $29 million (60 per cent) above the fiscal 2017 RRA Plan primarily due to:

- Bob Quinn 287 kV Shunt Reactor Spare project was $6.2 million above plan due to scope being added to control high voltage levels in the area in the event of a reactor failure;
- Kalum Outdoor Metalclad Switchgear Replacement project was $6.3 million above plan due to increased costs from higher than expected market prices for construction; and
- Unplanned emergency transformer replacements at Kelly Lake and Kidd 2 substations totalling $6.3 million.

The balance of the variance is due to a number of projects with smaller variances.

Fiscal 2018 capital expenditures were $26.4 million (33 per cent) under plan primarily due to the Mainwaring Station Upgrade Project being $31.3 million under plan due to the delay of the start of Implementation phase to re-evaluate project alternatives.

Capital addition variances

Fiscal 2017 capital additions were comparable to the fiscal 2017 RRA Plan.

Fiscal 2018 capital additions were $43.4 million (118 per cent) above the fiscal 2018 RRA Plan primarily due to:

- Several projects that were due to enter service in prior years, but entered service in fiscal 2018 due to schedule delays;
- Cost increases on Outdoor Metalclad Switchgear Replacement projects of $19.3 million; and
- Several unplanned emergency equipment replacements totalling $14.2 million for transformers at Kelly Lake substation, the Kidd 2 substation and a reactor at the GM Shrum Generation Station.

5.3.2.3 Protection and Control

Fiscal 2017 capital expenditures and capital additions were comparable to the fiscal 2017 RRA Plan.

Capital expenditure variances

Fiscal 2018 actual capital expenditures were $14.9 million (67 per cent) below the fiscal 2018 RRA Plan due to the NERC CIPv5 Compliance at Medium Impact T&D Stations project, which was based on planning assumptions from June 2015. It was expected that the project would be completed and put in-service on a partial basis in fiscal 2017 and fiscal 2018 and would be completed prior to fiscal 2019. However, the project will now be put in-service only at completion, which will be in fiscal 2019.

Capital additions variances

Fiscal 2018 capital additions were $12.8 million (64 per cent) below the fiscal 2018 RRA Plan due to the NERC CIPv5 Compliance at Medium Impact T&D Stations project discussed above.

5.3.2.4 Stations Auxiliary Equipment

Capital expenditure variances

Fiscal 2017 and fiscal 2018 capital expenditures were comparable to the fiscal 2017 and fiscal 2018 RRA Plan.

Capital addition variances

Fiscal 2017 capital additions were $15.5 million (53 per cent) below the fiscal 2017 RRA Plan, primarily due to several projects related to the Substation Wood Pole Replacements Program taking longer to complete than planned and now expected to be in-service in fiscal 2020 or fiscal 2021. A portion of the variance is also due to the delay in recognition of the capital expenditures as capital additions for the Station Safety and Minor Capital program, which will be completed in fiscal 2019.

Fiscal 2018 capital additions were comparable to the fiscal 2018 RRA Plan.

5.3.2.5 Stations Risk Mitigation and Telecommunications

Fiscal 2017 and fiscal 2018 actual capital expenditures and additions were comparable to the fiscal 2017 and fiscal 2018 RRA Plan.

5.3.3 Transmission Sustain - Lines

5.3.3.1 Cable Sustainment

Fiscal 2017 and fiscal 2018 capital expenditures and additions were comparable to the fiscal 2017 and fiscal 2018 RRA Plan.

5.3.3.2 Overhead Lines Life Extension

Capital expenditure variances

Fiscal 2017 capital expenditures were comparable to the fiscal 2017 RRA Plan.

Fiscal 2018 capital expenditures were $67.2 million (71 per cent) below the fiscal 2018 RRA Plan. This was primarily due to planned expenditures of $48 million for the Terrace to Kitimat Project not being spent. Due to changes to the load growth forecast and increases to the estimated total project cost for a new line, as well as updated asset health information, the leading alternative to construct a new line was revised to a refurbishment of the existing line.

Capital addition variances

Fiscal 2017 capital additions were $49 million (88 per cent) below the fiscal 2017 RRA Plan primarily due to:

- The Copper Conductor Replace – Phase 2 program which was $7.9 million below plan as construction activities proceeded slower than planned due to archaeological monitoring requirements; and
- The fiscal 2017 Overhead Structural Corrosion Protection, Transmission Wood Structure and Framing Replacements, and Spacer Damper programs were $25.7 million below plan due to delays with most of these capital additions being recorded in fiscal 2018 instead of fiscal 2017.

Fiscal 2018 capital additions were $10.3 million (17 per cent) below the fiscal 2018 RRA Plan. This is comprised of $18 million of capital additions planned in fiscal 2017 for Transmission Wood Structure and Spacer Damper Programs shifting to fiscal 2018 offset by delays to the in-service date for Circuit Refurbishment Projects and a Copper Conductor Replacement Project totaling $28 million, as a result of limited outage availability.

All other line items under Transmission Sustain-Lines in fiscal 2017 and fiscal 2018 for both capital expenditures and capital additions were comparable to the fiscal 2017 and fiscal 2018 RRA Plan.

5.4 Distribution Capital Expenditures and Additions Variance Explanations - Fiscal 2017 and Fiscal 2018

Table G-17 and Table G-18 compare the fiscal 2017 and fiscal 2018 capital expenditures and capital additions actuals against the fiscal 2017 and fiscal 2018 RRA Plan for the Distribution asset category. Sections 5.2.1 to 5.2.4 provide comparisons by sub-category for Distribution.

The distribution system improvement portfolio is primarily comprised of small projects, with the average project size in the $1 to 2 million range with short duration. The System Expansion and Improvement portfolio is subject to rapidly changing priorities and the planning processes must be dynamic to respond to the emerging needs on the distribution system. This may result in variances in the timing and selection of projects in the portfolio in a given year.

Table G-17 Distribution Plan and Actual Capital Expenditures Fiscal 2017 and Fiscal 2018

($ millions)	F2017				F2018			
	RRA	**Actual**	**Variance**	**% Variance**	**RRA**	**Actual**	**Variance**	**% Variance**
	1	2	3=2-1	4=3/1	1	2	3=2-1	4=3/1
Distribution Growth								
Customer Driven	155.2	179.9	24.7	16%	163.1	224.2	61.1	37%
System Expansion and Improvement	69.1	45.4	(23.7)	-34%	69.8	63.0	(6.8)	-10%
Uneconomic Extension Assistance	0.4	0.8	0.4	100%	0.5	0.3	(0.2)	-40%
Total Growth	224.7	226.1	1.4	1%	233.4	287.5	54.1	23%
Distributon Sustain								
System Expansion and Improvement	49.4	66.5	17.1	35%	29.7	92.8	63.1	212%
Asset Replacement								
Poles	81.7	94.5	12.8	16%	77.3	79.5	2.2	3%
Overhead Equipment	11.1	10.9	(0.2)	-2%	11.4	7.1	(4.3)	-38%
Underground Equipment	30.9	33.9	3.0	10%	29.5	32.5	3.0	10%
Trouble	10.5	17.0	6.5	62%	10.8	21.5	10.7	100%
Asset Replacement Total	134.2	156.3	22.1	16%	129.0	140.6	11.6	9%
Beautification	1.4	1.7	0.3	21%	1.4	1.7	0.2	15%
Total Sustain	185.0	224.5	39.5	21%	160.1	235.1	75.0	47%
Total Gross	**409.7**	**450.6**	**40.9**	**10%**	**393.5**	**522.6**	**129.1**	**33%**
Less: Contribution in Aid	(76.6)	(122.9)	(46.3)	60%	(78.4)	(140.6)	(62.2)	79%
Total	**333.1**	**327.7**	**(5.4)**	**-2%**	**315.1**	**382.0**	**66.9**	**21%**

Table G-18 Distribution Plan and Actual Capital Additions Fiscal 2017 and Fiscal 2018

($ millions)	F2017				F2018			
	Plan	Actual	Diff	% Diff	Plan	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1	1	2	3=2-1	4=3/1
Distribution Growth								
Customer Driven	154.4	175.4	21.0	14%	162.6	181.3	18.7	12%
System Expansion and Improvement	35.0	57.2	22.2	63%	78.5	49.9	(28.6)	-36%
Uneconomic Extension Assistance	0.4	0.2	(0.2)	-60%	0.5	1.0	0.6	124%
Total Growth	189.8	232.8	43.0	23%	241.6	232.2	(9.3)	-4%
Distributon Sustain								
System Expansion and Improvement	44.3	59.6	15.3	35%	26.5	65.6	39.1	148%
Asset Replacement								
Poles	82.0	88.6	6.6	8%	78.1	91.7	13.6	17%
Overhead Equipment	10.3	10.3	0.1	1%	11.3	9.4	(1.9)	-17%
Underground Equipment	33.8	22.7	(11.1)	-33%	29.6	30.4	0.8	3%
Trouble	10.5	6.1	(4.4)	-42%	10.7	14.3	3.6	33%
Asset Replacement Total	136.6	127.7	(8.8)	-6%	129.8	145.8	16.0	12%
Beautification	1.4	1.0	(0.4)	-30%	1.4	1.9	0.4	30%
Total Sustain	182.3	188.3	6.0	3%	157.7	213.2	55.5	35%
Total Gross	**372.1**	**421.1**	**49.0**	**13%**	**399.3**	**445.4**	**46.2**	**12%**
Less: Contribution in Aid	(76.0)	(79.7)	(3.7)	5%	(78.3)	(113.0)	(34.7)	44%
Total	**296.1**	**341.4**	**45.3**	**15%**	**321.0**	**332.4**	**11.5**	**4%**

5.4.1 Distribution Growth

5.4.1.1 Customer Driven

Fiscal 2017 capital expenditures were $24.7 million (16 per cent) above the fiscal 2017 RRA Plan and $61.1 million (37 percent) above the fiscal 2018 RRA Plan due to a significant increase in customer connection work as a result of higher than planned levels of new home construction in the Lower Mainland and South Vancouver Island. This work is difficult to plan as it is dependent on customer requests and their related timing.

Fiscal 2017 capital additions were $21 million (14 per cent) above the fiscal 2017 RRA Plan and the fiscal 2018 actual capital additions were $18.7 million (12 per cent) above the fiscal 2018 RRA Plan primarily due to the increase in capital expenditures noted above. These increases are partially offset by increased contribution in aid, discussed below.

5.4.1.2 System Expansion and Improvement (Growth)

Growth driven system expansion and improvement expenditures address existing capacity constraints to meet the anticipated customer load growth. The priority of growth-driven system upgrades is influenced by new customer load connections and general load growth of existing customers. This category of expenditures is subject to year over year fluctuations from plan as a result of changes in scope, cost and schedule for projects as well as variances between forecast and actual customer load growth.

The majority of capital additions and expenditures consist of the following categories:

- New feeder projects to offload heavily loaded existing feeders or to supply distribution customer load growth;
- Voltage conversion projects to convert the distribution primary voltage from 4 kV to 12 kV or from 12 kV to 25 kV to align with medium to long-term substation plans which require area loads to be transferred to an adjacent supply voltage, or aligned with plans for the existing substation for conversion to a higher voltage; and
- Line upgrades to increase feeder capacity, including 3-phasing, equipment upgrades or conductor upgrades.

Fiscal 2017 capital expenditures were $23.7 million (34 per cent) below the fiscal 2017 RRA Plan primarily due to the following:

- CBL New Feeder South Campbell River (VI-NVI-417) project was $6.7 million below plan due to timing of resourcing requirements;
- LOH 12F52 Voltage Conversion and Standby (LM-BBY-063) project was $5.7 million below plan due to a project delay which moved costs to fiscal 2018; and

- Voltage Conversion of ESQ1258 project (VI-SVI-259) was $5.2 million below plan due to the in-service date changing to fiscal 2018.

Fiscal 2018 capital expenditures were comparable to the fiscal 2018 RRA Plan.

Fiscal 2017 capital additions were $22.2 million (63 percent) above the fiscal 2017 RRA Plan due to a large number of projects less than $3.0 million that were not planned to be in-service during fiscal 2017, partially offset by the implementation of the Voltage Conversion of ESQ1258 (VI-SVI-259) project moving to fiscal 2018.

Fiscal 2018 capital additions were $28.6 million (36 per cent) below the fiscal 2018 RRA Plan which was primarily due to delayed in-service dates for the following projects:

- LOH 12F52 Voltage Conversion and Standby (LM-BBY-063) project for $9 million;
- Three new MLE Feeders to offload CBN (LM-FVE-607) project for $8 million; and
- COK Distribution Egress Reinforcement (LM-COQ-694) project for $5 million.

These projects are now expected to be in-service in fiscal 2019 and fiscal 2020.

5.4.2 Distribution Sustain

5.4.2.1 System Expansion and Improvement (Sustain)

System expansion and improvement sustaining expenditures maintain and improve distribution system performance including addressing customer reliability, safety risks and meeting regulatory, legal or environmental requirements.

Year over year fluctuations are the result of changes in the priority of required sustaining system upgrades which are influenced by recent distribution feeder reliability performance or other risks, including:

- Equipment additions and upgrades to address the worst performing circuits to improve customer reliability;
- Feeder reconfigurations and upgrades to address public or worker safety risks; and
- System upgrades to address other risks identified, including legal risks (e.g., deficient legal rights/statutory rights-of-way), regulatory risks (e.g., removal of PCB filled equipment), or environmental risks (e.g., potential impacts to environmentally sensitive areas, and risks to protected species).

Fiscal 2017 capital expenditures were $17.1 million (35 per cent) above the fiscal 2017 RRA Plan primarily due to higher than planned expenditures in projects to address issues related to the overhead distribution system connected to Illecillewaet Substation, a distribution under-build near Terrace and the advancement of the Quesnel Voltage Conversion Project due to more complicated project scope than planned and higher construction labour costs. In addition, there were higher than planned expenditures in the minor capital program to address system performance deficiencies and opportunity based improvements that were not planned.

Fiscal 2018 capital expenditures were $63.1 million (212 per cent) above the fiscal 2018 RRA Plan, primarily due to:

- Higher than planned expenditures in the minor capital program to address system performance deficiencies and opportunity based improvements;
- Cost increases on the H-Frame Elimination -Chinatown Program and Dawson Creek and Heffley Creek Reconfiguration projects due to more complicated project scope than planned and higher construction labour costs;
- Advancement of the QNL Voltage Conversion (NI-NC-160) project; and

- Unplanned expenditures for the deployment of DC Fast Charger Stations for Electric Vehicle charging.

Fiscal 2017 capital additions were $15.3 million (35 per cent) above the fiscal 2017 RRA Plan. This is primarily due to higher than planned expenditures in the minor capital program to address system performance deficiencies and opportunity based improvements, partially offset by a delayed in-service of a distribution line relocation in the Merritt Area originally planned in fiscal 2016.

Fiscal 2018 capital additions were $39.1 million (148 per cent) above the fiscal 2018 RRA Plan. This is primarily due to higher than planned expenditures in the minor capital program to address system performance deficiencies and opportunity based improvements. The main contributors to the variance are:

- Cost increases for the Heffley Creek Reconfiguration due to design change from overhead to underground plus higher civil costs due to civil construction resource constraints and challenging local work conditions;
- Cost increases for the Duncan Area Capacity project due to design change from overhead to underground, as well as increased scope of civil ductbank to accommodate planned customer load developments;
- Delayed in-service of the Prevost to Lake Cowichan Feeder Tie and the fiscal 2017 Overhead Automation Program moving from fiscal 2017 to fiscal 2018; and
- Unplanned expenditures for the deployment of DC Fast Charger Stations.

5.4.2.2 Asset Replacement

Fiscal 2017 capital expenditures were $22.1 million (16 per cent) above the fiscal 2017 RRA Plan primarily due to a $6 million variance for higher than planned number of wood pole replacements and a $7 million variance for higher than planned concrete pole replacements.

Fiscal 2018 capital expenditures were comparable to the fiscal 2018 RRA Plan.

Fiscal 2017 capital additions were comparable to the fiscal 2017 RRA Plan.

Fiscal 2018 actual capital additions were $16.0 million (12 per cent) above the fiscal 2018 RRA Plan primarily due to higher volumes of pole replacements and the timing of the assets going into service.

5.4.3 Contribution-in-Aid

Distribution expenditures were partially offset by Contribution in Aid of construction, which was $46.3 million (60 per cent) and $62.2 million (79 per cent) above the fiscal 2017 RRA Plan and fiscal 2018 RRA Plan, respectively. This was mainly due to the higher than planned expenditures for Distribution Customer Driven work which is dependent on customer requests.

Distribution additions were partially offset by Contribution in Aid of construction, which was comparable to the fiscal 2017 RRA Plan. Higher than planned volume for Distribution Customer Driven work resulted in fiscal 2018 actual additions of $34.7 million (44 per cent) above fiscal 2018 RRA Plan.

5.5 Business Support Capital Expenditures and Additions Variance Explanations - Fiscal 2017 and Fiscal 2018

Table G-19 and Table G-20 compare fiscal 2017 and fiscal 2018 capital expenditures and capital additions actuals against the fiscal 2017 and fiscal 2018 RRA Plan for the Business Support category (technology, properties, and fleet/other). Sections 5.2.1 to 5.2.4 provide comparisons by sub-category for Business Support.

Table G-19 Business Support Plan and Actual Capital Expenditures Fiscal 2017 and Fiscal 2018

($ millions)	F2017				F2018			
	RRA	Actual	Variance	% Variance	RRA	Actual	Variance	% Variance
	1	2	3=2-1	4=3/1	1	2	3=2-1	4=3/1
Business Support								
Technology	83.9	76.5	(7.4)	-9%	93.4	71.2	(22.2)	-24%
Properties	95.7	86.6	(9.1)	-10%	75.1	63.5	(11.6)	-15%
Fleet / Other	204.7	58.9	(145.8)	-71%	48.6	59.6	11.0	23%
Total	**384.3**	**222.0**	**(162.3)**	**-42%**	**217.1**	**194.3**	**(22.8)**	**-11%**

Table G-20 Business Support Plan and Actual Capital Additions Fiscal 2017 and Fiscal 2018

($ millions)	F2017				F2018			
	RRA	Actual	Variance	% Variance	RRA	Actual	Variance	% Variance
	1	2	3=2-1	4=3/1	1	2	3=2-1	4=3/1
Business Support								
Technology	81.6	81.6	-	0%	91.1	97.2	6.1	7%
Properties	68.3	54.8	(13.5)	-20%	118.2	126.9	8.7	7%
Fleet / Other	210.3	85.6	(124.7)	-59%	54.5	59.4	4.9	9%
Total	**360.2**	**222.0**	**(138.2)**	**-38%**	**263.8**	**283.5**	**19.7**	**7%**

5.5.1 Technology Variance Explanations

Technology's capital plan is dynamic due to emerging needs, opportunities and constraints. Changing business needs and priorities, technologies and resources may result in cost variability across the technology capital portfolio during the plan years. Table G-21 provides Technology plan and actual capital expenditures for fiscal 2017 to fiscal 2018, while Table G-22 provides plan and actual capital additions for fiscal 2017 to fiscal 2018. In these tables, "Technology" refers to technology investments managed by the Technology KBU, while "Other Technology" refers to technology investments managed by other business units.

Table G-21 Technology Plan and Actual Capital Expenditures Fiscal 2017 and Fiscal 2018

($ millions)	F2017				F2018			
	RRA	Actual	Variance	% Variance	RRA	Actual	Variance	% Variance
	1	2	3=2-1	4=3/1	1	2	3=2-1	4=3/1
Technology	81.4	75.0	(6.4)	-8%	92.4	70.4	(22.0)	-24%
Other Technology	2.5	1.5	(1.0)	-40%	1.0	0.8	(0.2)	-20%
Total	**83.9**	**76.5**	**(7.4)**	**-9%**	**93.4**	**71.2**	**(22.2)**	**-24%**

Table G-22 Technology Plan and Actual Capital Additions Fiscal 2017 and Fiscal 2018

($ millions)	F2017				F2018			
	RRA	Actual	Variance	% Variance	RRA	Actual	Variance	% Variance
	1	2	3=2-1	4=3/1	1	2	3=2-1	4=3/1
Technology	79.1	77.0	(2.1)	-3%	90.1	71.2	(18.9)	-21%
Other Technology	2.5	4.6	2.1	84%	1.0	26.0	25.0	2500%
Total	**81.6**	**81.6**	**0.0**	**0%**	**91.1**	**97.2**	**6.1**	**7%**

Capital expenditure variances

Fiscal 2017 capital expenditures were comparable to the fiscal 2017 RRA Plan.

Fiscal 2018 Technology capital expenditures were $22.0 million (24 per cent) below than the fiscal 2018 RRA Plan amount of $92.4 million. This was primarily due to:

- Delay in the Supply Chain Applications project for a regulatory application resulting in fiscal 2018 actual expenditures $34.2 million under plan;
- A re-organization in fiscal 2017 that moved part of Technology’s Telecommunications & Infrastructure planning function to the Line Asset Planning KBU, resulting in fiscal 2018 actual expenditures $10.9 million under plan; and
- T&D IT spending $5.5 million under plan including a $4.3 million reduction for the Graphic Work Design Tool project cancelled in October 2016.

Partially offset by:

- Infrastructure expenditures $12 million over plan for storage, PCs, and servers, as part of a shift in organizational priorities to focus on system reliability and resilience; and
- Enterprise application expenditures $4.7 million over plan for Microsoft software licenses and Energy Analytics platform upgrade.

The remainder is offset by amounts from various smaller projects.

Capital addition variances

Fiscal 2017 capital additions were comparable to the fiscal 2017 RRA Plan.

Fiscal 2018 Technology actual capital additions were $18.9 million (21 per cent) below the fiscal 2018 RRA Plan. This was primarily due to:

- Cancellation of the Graphic Work Design project in October 2016, resulting in fiscal 2018 actual additions $15 million under plan; and
- Re-organization in fiscal 2017 that moved part of Technology's Telecommunications & Infrastructure planning function to the Line Asset Planning KBU.

The remainder is offset by amounts from various smaller projects.

Capital additions for Other Technology were $25 million above the fiscal 2018 RRA Plan. This category primarily represents technology assets that were constructed as part of other projects that were included in the Business Support –Other capital plan. The actual capital additions for the technology related assets for these projects are included in the capital additions in this category. This includes:

- Energy Management System 3.0 Upgrade project which included $17.4 million of computer hardware and software;
- Physical Key Management project for $4.3 million; and
- Amounts from various smaller projects.

5.5.2 Properties Plan and Actual Capital Expenditures and Additions Fiscal 2017 and Fiscal 2018

Table G-23 Properties Plan and Actual Capital Expenditures Fiscal 2017 and Fiscal 2018

($ millions)	F2017				F2018			
	RRA	Actual	Variance	% Variance	RRA	Actual	Variance	% Variance
	1	2	3=2-1	4=3/1	1	2	3=2-1	4=3/1
Interior Space Renovations	11.6	11.4	(0.2)	-2%	11.9	9.9	(2.0)	-17%
Building Development	54.8	48.0	(6.8)	-12%	44.4	25.2	(19.2)	-43%
Building Improvements and Others	26.3	23.1	(3.2)	-12%	18.8	28.4	9.6	51%
Other Properties	3.0	4.1	1.1	37%	-	-	-	0%
Total	**95.7**	**86.6**	**(9.1)**	**-10%**	**75.1**	**63.5**	**(11.6)**	**-15%**

Table G-24 Properties Plan and Actual Capital Additions Fiscal 2017 and Fiscal 2018

($ millions)	F2017				F2018			
	RRA	Actual	Variance	% Variance	RRA	Actual	Variance	% Variance
	1	2	3=2-1	4=3/1	1	2	3=2-1	4=3/1
Interior Space Renovations	21.6	19.2	(2.4)	-11%	11.9	12.1	0.2	2%
Building Development	4.6	8.4	3.8	83%	87.5	81.4	(6.1)	-7%
Building Improvements and Others	38.2	26.5	(11.7)	-31%	18.8	30.0	11.2	60%
Other Properties	3.9	0.7	(3.2)	-82%	-	3.4	3.4	0%
Total	**68.3**	**54.8**	**(13.5)**	**-20%**	**118.2**	**126.9**	**8.7**	**7%**

Capital expenditure variances

Fiscal 2017 capital expenditures were comparable to the fiscal 2017 RRA Plan.

Fiscal 2018 capital expenditures were $11.6 million (15 per cent) below the fiscal 2018 RRA Plan primarily due to deferring several projects:

- The Materials Classification Facility project was put on hold for most of fiscal 2017 as capital funding constraints were being assessed across BC Hydro. This project has now recommenced; and

- The Construction Services/Lower Mainland Transmission Facility project, the Dawson Creek Field Office project, and the Fleet Facility project were all deferred in fiscal 2017 for five years, and are now due to recommence in fiscal 2022 or fiscal 2023.

Capital addition variances

Fiscal 2017 capital additions were $13.5 million (20 per cent) below the fiscal 2017 RRA Plan as several projects that were due to go into service in fiscal 2017 were delayed and went into service in fiscal 2018.

Fiscal 2018 capital additions were comparable to the fiscal 2018 RRA Plan, and reflect the capital additions of some projects delayed from fiscal 2017.

5.5.3 Fleet/Other Plan and Actual Capital Expenditures and Additions Fiscal 2017 and Fiscal 2018

Table G-25 Fleet/Other Plan and Actual Capital Expenditures Fiscal 2017 to Fiscal 2018

($ millions)	F2017				F2018			
	RRA	Actual	Variance	% Variance	RRA	Actual	Variance	% Variance
	1	2	3=2-1	4=3/1	1	2	3=2-1	4=3/1
Fleet	33.9	26.9	(7.0)	-21%	30.9	31.0	0.1	0%
Other	170.8	32.0	(138.8)	-81%	17.7	28.6	10.9	62%
Total	**204.7**	**58.9**	**(145.8)**	**-71%**	**48.6**	**59.6**	**11.0**	**23%**

Table G-26 Fleet/Other Plan and Actual Capital Additions Fiscal 2017 to Fiscal 2018

($ millions)	F2017				F2018			
	RRA	Actual	Variance	% Variance	RRA	Actual	Variance	% Variance
	1	2	3=2-1	4=3/1	1	2	3=2-1	4=3/1
Fleet	40.3	38.2	(2.1)	-5%	32.4	29.8	(2.6)	-8%
Other	170.0	47.4	(122.6)	-72%	22.1	29.6	7.5	34%
Total	**210.3**	**85.6**	**(124.7)**	**-59%**	**54.5**	**59.4**	**4.9**	**9%**

5.5.3.1 Fleet Actual to Plan Variances Fiscal 2017 to Fiscal 2018

Fleet capital expenditures and capital additions for fiscal 2017 and fiscal 2018 were comparable to plan.

5.5.3.2 Other Actual to Plan Variances Fiscal 2017 to Fiscal 2018

The Other category includes expenditures and additions related to Land Purchases, Materials Management upgrades, Field Operations tools and equipment, Control Centre systems upgrades, and workforce training equipment.

Capital expenditure variances

Other capital expenditures for fiscal 2017 were $138.8 million (81 per cent) below the fiscal 2017 RRA Plan mainly due to variances from planned land purchases. One of the planned land purchases was completed and the actuals were recorded in the Transmission Regional System Reinforcement Category as the land will be used for a future substation development. The other planned land purchases were not completed due to delays or due to additional planning being completed. Variances caused by these two planned land purchases were offset by a number of variances less than $5 million per project in each of the 'Other' capital categories.

Fiscal 2018 capital expenditures were $10.9 million (62 per cent) above the fiscal 2018 RRA Plan, primarily due to unplanned work related to Physical Key Management that was necessary for risk mitigation, timing of equipment delivery, and SMI Field Area sustainment work.

Capital addition variances

Fiscal 2017 capital additions were $122.6 million (72 per cent) below the fiscal 2017 RRA Plan primarily due to the variances in planned land purchases discussed above.

Fiscal 2018 capital additions were comparable to the fiscal 2018 RRA Plan.

5.6 Site C Project Capital Expenditures Variance Explanations - Fiscal 2017 and Fiscal 2018

Table G-27 compares fiscal 2017 and fiscal 2018 capital expenditures actuals against the fiscal 2017 and fiscal 2018 RRA Plan for the Site C Project, with variance explanations below the table.

Table G-27 Site C Project Plan and Actual Capital Expenditures Fiscal 2017 to Fiscal 2018

($ millions)	F2017				F2018			
	RRA	Actual	Variance	% Variance	RRA	Actual	Variance	% Variance
	1	2	3=2-1	4=3/1	1	2	3=2-1	4=3/1
Total Site C	**742.5**	**662.7**	**(79.8)**	**-11%**	**716.5**	**704.9**	**(11.6)**	**-2%**

Fiscal 2017 capital expenditures were $79.8 million (11 per cent) below the fiscal 2017 RRA Plan. This was primarily due to a shift of some property purchases and mitigation and compensation expenditures into future periods, as well as delayed expenditures on highways, construction of site telecom, transmission lines and clearing for the lower reservoir.

Fiscal 2018 capital expenditures were comparable to the fiscal 2018 RRA Plan.

There were no capital additions for the Site C Project in fiscal 2017 or fiscal 2018.

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix H

Fiscal 2020 to Fiscal 2024 Capital Plan

Discussion/Information

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EXECUTIVE SUMMARY

This briefing provides a summary of BC Hydro's updated Capital Plan (Capital Plan) with an outline of major investments, related risks, and opportunities. The Capital Plan includes five years of investment level detail, for F2020 to F2024, and a high level projection for F2025 to F2029. The F2020-F2024 Capital Plan is guided by the capital scenario that supported the Comprehensive Review. Next year's capital planning will focus on re-building 10 years of investment level detail.

The capital expenditures for the first two years (F2020-F2021) of the Capital Plan forms the basis of the capital information included in the F2020/F2021 Revenue Requirements Application.

This Capital Plan provides a consistent and appropriate approach to the management of risks across all business groups, and supports the delivery of reliable, affordable, clean electricity throughout BC safely. A recent independent audit by the Office of the Auditor General (OAG) found that BC Hydro's capital asset management systems and practices have reached generally advanced maturity levels. The audit concluded that BC Hydro had demonstrated good asset management practices and did not include any recommendations.

Background

To preserve continuity with the Revenue Requirements Application (RRA), the information provided in this briefing is presented based on asset categorization, as shown in previous years.

This fiscal's capital planning processes ran in parallel with the first phase of the Comprehensive Review (Review). The capital scenario included in the Review recommendations informed the targets for Enterprise Capital Planning and was incorporated into BC Hydro's Q1 2018 forecast.

Investment level details were developed for years F2020-F2024, and directional targets are provided for years F2025-F2029. Detailed capital investment requirements beyond F2024 will be informed by future initiatives, including BC Hydro's next Integrated Resource Plan (IRP).

Enterprise Capital Planning

BC Hydro's Enterprise Capital Planning process began with executive level strategic direction in the form of a portfolio level assessment of BC Hydro's long term capital investment needs based on the principles of balancing affordability and system performance, while also continuing to safely operate our system. In June 2018, a capital scenario was established that supported the Review, and was aligned with executive level direction on long-term capital investment levels.

The next step in the development of the Enterprise Capital Plan was bottom up planning within the various business groups. Each business group identified investments to address system needs and risks, while applying the enterprise-wide framework for capital prioritization and considering any labour and financial constraints.

Once bottom up planning and business group portfolio planning concluded, the capital planning data was compiled for peer reviews at the enterprise level. Peer reviews were conducted jointly across the planning groups to review the capital portfolio.

Peer reviews this year focused on three main areas: an overall summary of each portfolio, the quality of a sample set of investment justifications documents which provided detailed information on the investments such as the problem statement, desired outcome and potential alternatives, and the risk profile of the Capital Plan. During the portfolio summary reviews, re-direction of funding within the

Enterprise Portfolio occurred, increasing the amounts allocated to Technology and Properties assets in the earlier years of the plan, so that the investments in these portfolios were more evenly distributed over the long-term. The re-direction was required to smooth investment levels and avoid resourcing variability over the F2020-F2024 period. The re-direction is neutral to all groups over the F2020-F2029 period.

Capital Investment Drivers

The main drivers of the capital plan are common across the business and remain unchanged from prior years.

Ageing Assets – A large portion of BC Hydro's system was built in the 1960s and 1970s and is reaching or exceeding expected end-of-life. A significant proportion of the risks facing BC Hydro's major assets can be attributed to their age. The physical condition, performance, maintenance history, and criticality of equipment and facilities are significant drivers for planning and prioritizing refurbishment or replacement.

Reliability – The reliability of BC Hydro's assets (e.g. equipment associated with the power system, Properties, Technology, and Fleet assets) can be measured over time. Equipment health assessments at each point in time are reflective of the condition of the assets, maintenance practices and long-term investment trends. Long term trends indicate increasing or declining reliability risk for use in asset management.

Capital investment is paramount to the total performance of the system, and the indicators of investment adequacy are consistent performance metrics over time, and the number and impact of in-service failures on critical assets. The BC Hydro Service Plan sets targets for system performance measures, and these lagging indicators continue to indicate that BC Hydro is appropriately managing our service delivery risks.

System Growth – Over the coming years, BC Hydro will continue to experience load growth in some areas of the province, even after taking estimated conservation impacts into account. This includes actual and potential growth due to the oil and gas sector in the Peace and North Coast regions. The need to meet this increased demand while operating the system safely and reliably will influence asset management and capital expenditure decisions. New investments continue to be required in both distribution and transmission infrastructure to meet customer demand growth and to connect new supply of electricity. Integrated information technology improvements will be needed to support expansion in a changing environment.

Prioritization Methodology

The investments in the Capital Plan have been assessed and scored in accordance with the enterprise-wide framework for capital prioritization, to ensure BC Hydro is mitigating asset-related risks in an appropriate way. Dependencies between projects, opportunities to bundle work for more efficient delivery and resource considerations are some of the factors that must also be considered along with the risk or value score, to ensure each Business Group's portfolio of investments aligns with strategic and performance objectives, as well as planning targets.

The framework describes the assessment and prioritization process related to all proposed capital projects that are material in nature. Projects are prioritized based on the primary driver of the proposed project:

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- Capital projects that primarily mitigate risk are scored for prioritization using a methodology that is aligned with the BC Hydro Corporate Risk Matrix (see attachment),
- Capital projects that primarily create value are scored for prioritization using a net value per dollar invested metric. The value prioritization is mainly used for some capital expenditures in the Technology Portfolio.

The framework classifies capital investments into one of three categories:

- Mandatory investments driven by legal and regulatory requirements.
- Committed investments not to be postponed. This category includes projects that are economically unreasonable to stop as deferral of these projects would result in significant additional costs to suspend and then restart at a later date and may result in the loss of warranty protection on major equipment.
- Investments to be prioritized (including projects that will be in the Identification or Definition phase by F2020, and could be re-prioritized without significant economic losses).

Risk profile – Application of the enterprise-wide framework for capital prioritization enabled all Business Groups to calculate risk or value scores, and provide a consistent representation of risk across the enterprise, which involved the following steps:

- Business Groups independently assigning each investment a risk score associated with postponing the investment,
- Comparing similar investments between Business Groups (e.g. roof replacements) to ensure consistent application of the Framework,
- Comparing investments with the same risk score between Business Groups to ensure comparability,
- Verifying and challenging the proposed investments, including the risk scoring and timing.

The risk profile of the F2020-F2024 Capital Plan is shown below by “to be prioritized” capital additions by risk score:

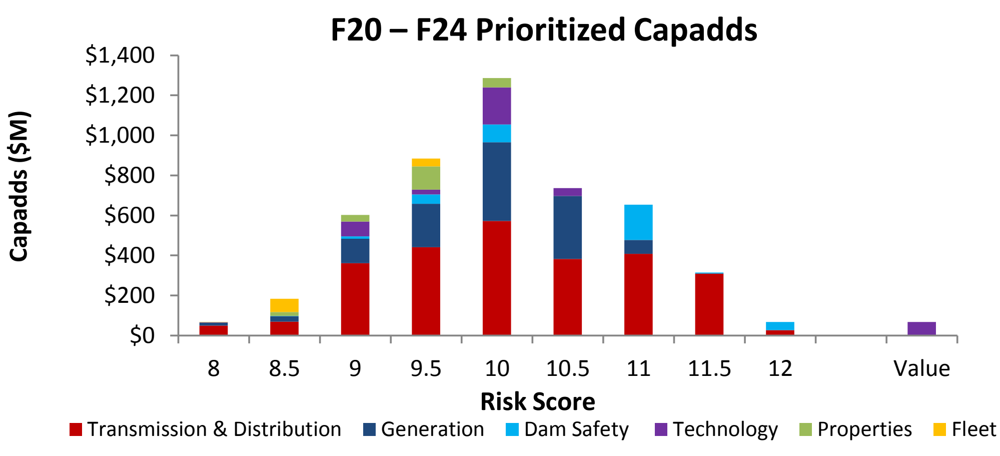

Figure 1: F2020-F2024 Capital Plan Risk Profile

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To refine BC Hydro's framework for capital prioritization, and develop abilities to optimize investments across the Enterprise Portfolio, the Asset Investment Planning tool project has been initiated to develop an Enterprise Wide Value Framework and common IT platform. This project's objective is to maximize portfolio value at the enterprise level, by providing a framework and tool to optimize the scope and timing of investments. This project is currently in the definition phase, and is forecasting completion between F2020 & F2021.

Capital Plan Delivery Resources

Where labour resources have been identified as a risk to the delivery of the portfolio, the demands on the labour pool required to deliver each investment and the availability of the resources are estimated in consultation with the resource management groups at the portfolio level. The level of investment in this Capital Plan is a reduction from the previous 10-Year Capital Plan, therefore the portfolio analysis completed for the previous plan is still valid, and no significant new resource constraints are expected. The resource availability of some groups identified as constraining resources in previous capital planning cycles, mainly Communications, Protection and Control Technologists, have been managed over the past several years to ensure that higher risk investments are not unduly delayed.

Capital Expenditures & Additions

BC Hydro is forecasting net annual average capital expenditures of approximately $1.6[1] billion per year or total net capital expenditures of $8.2[1] billion for F2020-F2024. For capital additions, BC Hydro is forecasting a net annual average of approximately $1.3[1] billion per year, or total net capital additions of $6.7[1] billion for F2020-F2024. Figures 2 and 3 below show the capital expenditure and additions breakdown.

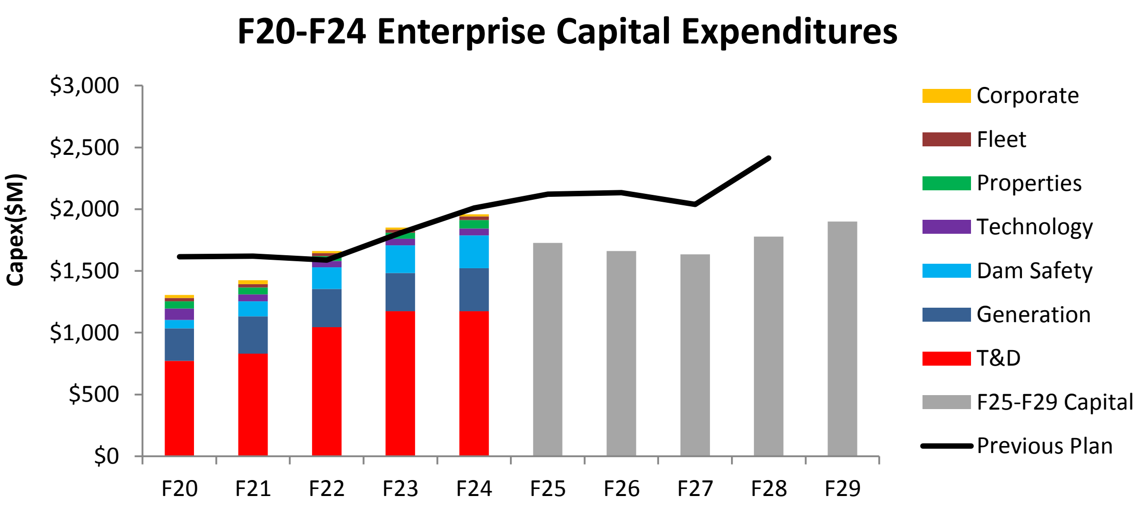

Figure 2: F2020-F2024 Capital Expenditure compared to Previous Plan

[1] Excludes Site C and Waneta

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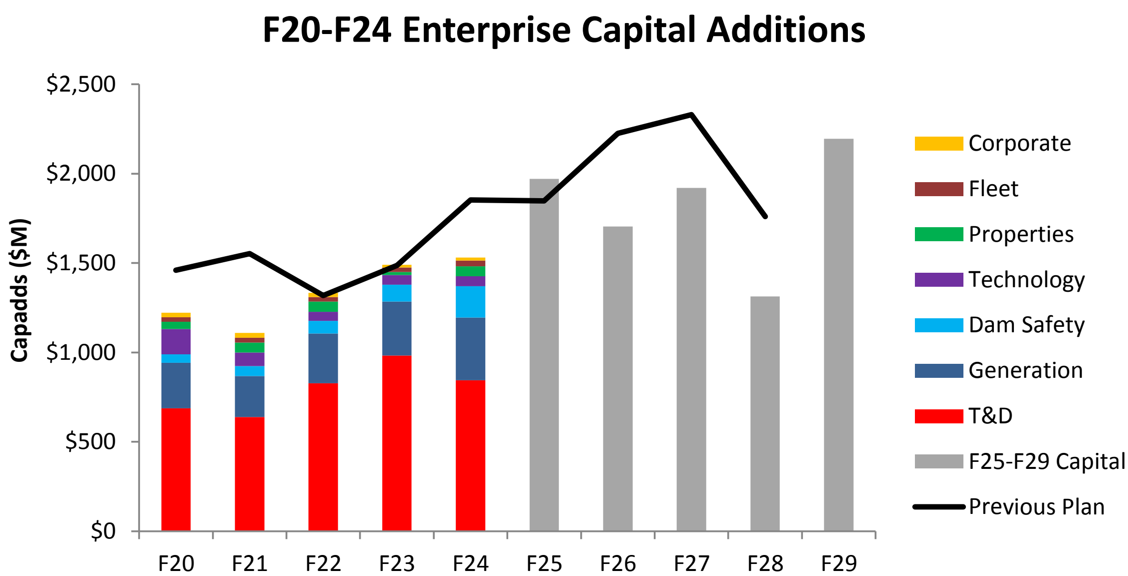

Figure 3: F2020-F2024 Capital Additions Compared to Previous Plan

This Capital Plan has been reduced by a total of approximately $2.7 billion in additions over the 10 year period, in comparison to the Previous Plan and considering forecasted additions for F2029. This reduction in capital supports BC Hydro's strategic goal of keeping electricity rates affordable for our customers. Reductions were defined by the following key principles:

- Excluding investments that are classified as mandatory as per the framework for capital prioritization,
- Minimizing reductions to active/committed investments where the financial impact of deferral/cancellation outweighed the reduction savings,

An exercise to identify potential opportunities to shift growth driven investments in advance of the completion of the updated load forecast was also undertaken. These investments were deferred within this Capital Plan, and these deferrals will be validated against the load forecast in spring 2019. In the F2020 – F2024 period, reductions have been taken from both the Sustain and Growth portfolios keeping the proportions within the portfolio relatively equal. Figure 4 below compares the F2020-F2024 capital additions by growth and sustain versus the Previous Plan totals.

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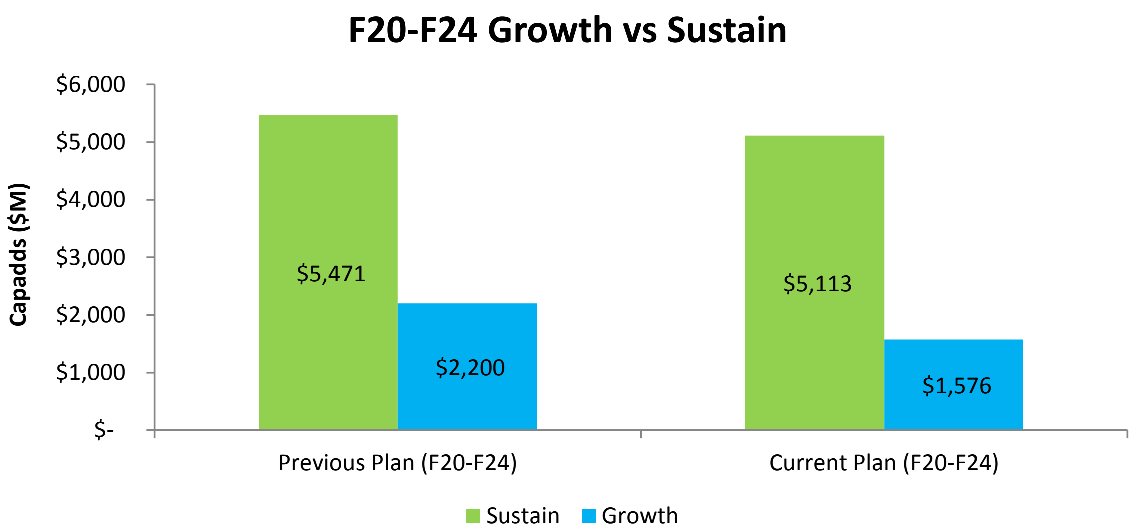

Figure 4: F2020-F2024 Capital Additions by Growth & Sustain

Dam Safety

Despite the overall reduction of capital expenditure from preceding Capital Plans described above, investment in Dam Safety within this Capital Plan has not been reduced in response to affordability considerations. Dam Safety risk reduction targets remain as they were in previous Plans and align with the approach that was approved by the Board in 2014; namely to "manage the whole fleet of dams so that there is no significant deterioration in the risk position and that the overall level of risk is kept well within the limits considered to be tolerable." In practical terms, this Capital Plan aims to reduce the aggregated Vulnerability Index of issues identified in the Dam Safety Issues Database at a rate that will generally offset the historic (and expected) rate of additions to the Vulnerability Index through newly identified or understood issues.

Relative to the previous Capital Plan, however, the current plan does represent a relatively small reduction of capital expenditures and a larger reduction of capital additions within the Dam Safety portfolio over the first half of the Capital Plan, (F2020-F2024). This is primarily due to schedule extensions of the three Campbell River projects that are currently in-flight: the seismic upgrade of John Hart Dam, the seismic and reliability upgrades of the Ladore Falls Dam spillway gates, and the reservoir discharge upgrades at Strathcona Dam. Developing and confirming the preferred alternatives for these three large and complex projects is forecast to be completed approximately one year later than previously thought as new, more beneficial and constructible concepts are being taken through Feasibility Design. The effect of these schedule extensions has been to delay the forecasted construction dates and to shift approximately $170M of capital additions to just outside the F2020-F2024 window. The net effect on the overall F2020-F2029 Capital Plan is ultimately neutral, however, as capital additions in the current plan catch up to those of the previous plan by F2026 when the Campbell River projects are to be completed.

Pursuant to the approach described above, the Capital Plan is right-sized to prevent deterioration of the current risk profile related to BC Hydro's dams and reservoirs and will address several issues that significantly contribute to that risk. By the end of this plan, projects expected to have been completed include the following: the in-flight Campbell River projects that will bring several existing earthquake and flood-related risks—the most pressing and least tolerable ones in our fleet of dams—to within broadly accepted levels; improved flow control at Comox and Puntledge Dams that will significantly reduce public safety risks along the heavily used Puntledge River; seismic and reliability upgrades of the spillways and gate systems at WAC Bennett, Mica and Revelstoke Dams that will assure reliable flood and post-earthquake reservoir discharge at BC Hydro's three largest dams; and seismic upgrades of the power tunnel and ancillary structures between Alouette and Stave Lakes that will assure post-earthquake reservoir discharge and drawdown capability and eliminate the need for expensive upgrades to the spillway at Alouette Dam. Moreover, several important projects to address poor seismic withstand, seepage control and/or deteriorating condition will be nearing completion or well underway at several dams: La Joie, Cheakamus, Duncan, and Peace Canyon. Projects to replace the last wood stave penstocks in the fleet at Ash River and Puntledge will be well advanced. These and several other, smaller projects will allow BC Hydro to meet its stated goal to "manage the whole fleet of dams so that there is no significant deterioration in the risk position..."

The current Capital Plan addresses the same Dam Safety risks over the course of the next ten years as did the previous plan, and further provides for re-initiating and progressing the major upgrade of La Joie Dam. In the interim, the risks related to these works will continue to be managed in the same manner as at present: in the case of Campbell River, by continued public outreach, education and coordination with local authorities, and in the case of La Joie by managing the reservoir to a lower elevation. Risks that are being retained at other dam and reservoir sites—both for those that are to be addressed within this Capital Plan and those that are to be addressed at a later date—will be managed, as warranted and practicable, by similar methods documented in the dams' Operation, Maintenance and Surveillance Manuals or supplemental Interim Dam Safety Risk Management Plans.

Generation

BC Hydro has 30 hydroelectric, 2 thermal generating stations, and 1 synchronous condenser station. This includes a total of 89 units, and 79 dams and civil structures. BC Hydro's generation facilities are divided into three categories of criticality to help focus asset management efforts: Key, Strategic, and Available Energy facilities. The seven Key Generating Facilities represent those with installed capacity greater than 200MW and provide 90% of the average annual electricity generated by BC Hydro. The 18 Strategic Facilities represent 9% of the average annual electricity generated by BC Hydro. The seven remaining facilities are known as Available Energy Generating Facilities and provide 1% of the average annual electricity generated.

The condition of the most critical generating assets are assessed over time through an established methodology. Asset condition is an important component of assessing risk given that assets in worse condition generally have an increased likelihood of failure. The investment strategy has focused on preserving a high level of reliability at the Key facilities given their critical role in the fleet, with a focus being placed on the three largest facilities (GM Shrum, Mica and Revelstoke). Bridge River is the smallest of the Key facilities, and is now receiving an increased level of investment to address a number of asset condition and reliability concerns. There has historically been a lower level of investment in the Strategic facilities (excluding John Hart and Ruskin) and minimal investment in the Available Energy facilities, given resource and capital constraints. To date, end-of-life failures have been experienced at Aberfeldie, Lake Buntzen 2, Alouette, Elko, and Shuswap generating stations and a number of these remain out of service. The expected condition of the generation assets at the end of F2024 are described below by category of criticality and high value assets:

- **Key Facilities:** The overall condition of the critical assets at the Key facilities is anticipated to be relatively constant, with a small improvement over time. The largest contributor to the improvement is the work being undertaken at the Bridge River facility. The largest retained long term risks at the key facilities are the Kootenay Canal Generators 3 & 4 (~290MW at risk), and with Revelstoke Generator 2 (~500MW). These assets will be monitored carefully, as investment in these assets is not anticipated to be completed within the next 10 years.
- **Strategic Facilities:** The Strategic hydroelectric facilities will see an improvement in condition driven by the completion of investments at the Ruskin and John Hart facilities, and with the completion of the generator replacement at Cheakamus expected to be completed shortly. However, the level of investment in a number of smaller strategic facilities has been reduced. Clowhom (33MW) and Ash River (28MW) have multiple assets with known condition issues, and reduced investment levels increase the likelihood of an extended forced outage, or the facilities being forced out of service. Alouette (9MW) is already out of service. The impact of these outages on the transmission system will need to be investigated.
- **Available Energy Facilities:** The seven Available Energy facilities are less critical to system reliability. Aberfeldie is relatively new (F2008), and Whatshan (54MW) is mid-life. Investments in the remaining five Available Energy facilities will be low. The Elko facility (12MW) is out of service, as well as one of the units at Shuswap (3MW). Based on the current plan, these will not be restored in the next 10 years. The other four smallest Available energy facilities are also at or approaching their end of life and all investments will receive a high level of scrutiny to avoid the risk of over investment in the assets. There is a high likelihood that a number of these will experience long outages, or be forced out of service over the next 10 years.
- **Penstocks:** These are important and high value assets. Across the fleet, a number of penstock coatings have failed or are exhibiting significant deterioration. If not mitigated in a timely fashion, the window of opportunity to recoat these penstocks will be missed, leading to corrosion of the underlying material, and a much more expensive future replacement or refurbishment. A number of penstock recoating projects are underway or proposed over the next 5 to 10 years to improve the condition of these very important assets.

Transmission & Distribution

Capital investments on the Transmission & Distribution system are driven by ageing assets, load growth in certain regions of the province, the need to manage customer reliability and address any safety needs on the system. The overall objective of the Transmission & Distribution capital plan is to:

- Address load and system growth through the addition of system capacity. An example of a capital project that will add additional capacity in the system is the Peace Region Electrification System project that is driven by the increase in the forecasted industrial load in the region.
- Manage assets reaching end of life through targeted investments to address critical assets and the highest asset risks.
- Maintain current reliability levels by addressing the worst performing circuits and install automated devices.
- Invest in safety and environmental risk mitigation particularly with regards to removing PCB contaminated oil from the system by December 2025 according to Environment Canada regulation through the replacement of end of life assets.

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The Transmission & Distribution capital additions in the F2020-F2024 Capital Plan total approximately $4.0 billion, split between growth ($1.6 billion) and sustain ($2.4 billion) after Contributions in Aid (CIA) from customers.

The Growth Capital Portfolio reinforces the Transmission & Distribution system to meet increasing firm domestic load and provide generator interconnections and dispatch flexibility. Projects within this portfolio cover bulk transmission system assets, regional transmission system assets, transmission load and Independent Power Producer interconnections and local distribution system assets. The size of the portfolio is reflective of a domestic load that is expected to grow in some areas across the province like the Peace Region. Uncertainty of the load forecast is a risk to this portfolio. For this capital planning cycle, a number of growth driven investments were deferred from the Capital Plan and will be validated against the updated five year energy forecast in spring 2019. Wherever possible, the Growth Portfolio projects are coordinated with the Sustainment Portfolio to develop effective solutions that address both system capacity shortfall and end of life needs.

Another component of the Growth Capital Portfolio includes projects related to new Transmission Voltage customer load and generation interconnections. Projects included in this category of the Capital Plan are either committed or have a high probability of proceeding. Obligation to serve loads and generators is governed through BC Hydro's Open Access Transmission and Electric Tariffs. New customer load requests are a risk for this portfolio, due to uncertainty in timing, location and scope. ,

Also, included in this portfolio are distribution customer connections. The level of economic activity in the province is the single largest influence on the customer capital expenditures. Housing starts, infrastructure investment, and new industries such as cannabis grow operations have contributed to an unprecedented construction boom over the last three years and therefore unprecedented volumes of distribution customer connection requests.

The main objective of the Sustaining Capital Portfolio is to cost-effectively maintain a reliable Transmission & Distribution system and mitigate asset risks including life-safety, environmental, extreme weather, seismic and fire. Expenditures in this portfolio will replace end-of-life assets, manage reliability trends on the system and address other risks. Most of the sustain expenditures are for the replacement of component parts (e.g. circuit breakers and wood poles) with varied life expectancies. Bottom up planning was used to identify the investments required to sustain the most critical assets, and address the highest asset risks. The end-of-life investments were developed to maximize the life cycle value of the Transmission & Distribution assets. While in most instances end-of-life replacements are accomplished through proactive replacements, in some asset classes "run to failure" is used to minimize the life cycle cost of managing the assets where the associated risk of failure is low. Examples of "run to failure" asset classes are overhead distribution transformers and transmission line insulators.

To understand long-term trends in asset replacement needs, asset health for various asset classes is developed using asset survival curves and demographic data to support decisions around the required rate of asset replacements. Funding levels in the current Capital Plan will result in an increase in assets with poor and very poor asset health ratings and potential for a decline in customer reliability. Transmission & Distribution will minimize this risk by targeting investments to critical assets and the highest asset risks, and by monitoring system reliability to determine whether the level of end-of-life replacements need to be adjusted.

Customer reliability expenditures are also part of the Sustaining Capital Portfolio. These expenditures contribute to maintaining the overall system reliability by installing automated devices such as circuit reclosers, and by targeting the distribution circuits that are performing poorly. The scope of customer reliability projects may include new standby feeders, feeder ties, as well as circuit undergrounding or reconfiguration, line relocations and protection upgrades.

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Properties

Historically, the majority of Properties capital spend has been directed at mitigating Safety or Financial risks across the 100+ building portfolio. Over the past 10 years, major investments around the province, coupled with a sustaining capital program targeted at replacement of the most critical end of life assets, have addressed many of the inherent risks associated with an aging field building stock. In total 37 field buildings have been upgraded and in particular, 7 out of the 8 high criticality large regional field offices have been redeveloped, the scope of which included the operations yards, warehouses, truck bays, security and IT infrastructure, office areas, as well as seismic upgrades.

Going forward the Properties capital investment strategy is summarized as follows:

- Building Development Projects (field building replacement projects): 5 with a total investment of $105M are currently in definition or implementation (e.g. Material Classification Facility, Chilliwack). In addition, the redevelopment of the final high criticality large regional field office located in Kamloops is scheduled to enter definition phase in F2020. By F2025, Properties will also complete those projects that were previously in definition phase and subsequently deferred (e.g. Construction Services/Lower Mainland Transmission facility in Surrey);
- Building Improvement Projects: a reduction from an average annual spend of $20-30M p.a. to $17M in sustaining capital investments is reflective of the investments to date as well as balancing affordability with asset performance and risk. Focus will be on the most critical end of life assets, as well as completion of a modest number of field building interior upgrades and construction/expansion of truck bay facilities (e.g. Hope interior upgrades and Cranbrook truck storage). This reduced capital spend will result in necessary deferral of certain projects across the portfolio and may result in higher facility operating costs and unplanned asset component failures.

Technology

The proposed plan is sufficient to complete all currently active projects through the end of F2021, including the Supply Chain Applications project. However, the plan drops rapidly from F2020 to F2021 to approximately 30% below historical (F2015 to F2019) spend levels and is therefore allocated primarily to compliance and risk mitigation initiatives. Infrastructure will be renewed, information systems will continue to run and bills will be paid. Compliance investments, essential replacements, licensing, upgrades and capacity improvements will also continue to be done. New, enhanced and extended technology foundations and solutions are not funded. This may result in opportunity costs for BC Hydro as technology-based business efficiencies are not enabled.

A focus on operational continuity of data center infrastructure, software platforms and devices will ensure the availability, appropriate access, and integrity of BC Hydro's technology solutions. A lower level of continued investment in business-driven solutions will serve to correct operational issues, and improve cybersecurity, information management, performance and core system resilience. The proposed plan assumes 2% annual inflation and 1% annual growth in demand for IT expenditures in funded categories. This is lower than we've seen in recent years and may be understated.

Business demand for technology solutions is likely to be underserved. This includes IT support for business initiatives and improvements or extensions of existing IT solutions. Business units may seek to fund their own technology solutions as an opportunity to address business needs.

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Fleet Services

Despite routine, preventative maintenance, fleet assets (vehicles, equipment, trailers), relied upon by staff across B.C. to operate our system and deliver on capital projects, inevitably deteriorate as they age and eventually reach end-of-life (EOL). The Fleet Services capital program is a perpetual sustainment program to replenish fleet assets and support safe, efficient operations.

Under this Capital Plan, ~690 End-of-Life (EOL)/poor-condition assets will be replaced by the end of F2024. This plan does not include sufficient capital to replace all assets forecast to reach end-of-life during the period. As a result, the backlog of units deferred for replacement will continue to grow (from ~80 EOL units in F2020 with an estimated replacement value of $11.2M, to ~440 EOL units by the end of F2024 with an estimated replacement value of $39.8M). With these deferred replacements, the fleet assets will continue to age and deteriorate during the plan period.

The plan has no funding/contingency for any net additions or for significant unit upgrades to the fleet that may be required by the business (for example, due to changes in engineering standards, work methods, staffing or operational priorities). These types of requests would need to be funded via approval of ex-plan capital, be denied, or be absorbed into the existing Fleet Services capital budget through deferral.

The following risks are associated with the plan:

- Increased Fleet OMA: deferring replacement and aging of the fleet create pressures due to increased maintenance and repair costs. We will have to work through any resulting cost pressures.
- End-User Departments will experience more vehicle/asset downtime. This is expected to result in decreased productivity & efficiency, less operational flexibility and may impact crew response time. The result may be less project work completed on-time/budget and delays in implementing any desired changes to work methods that rely on acquisition of different fleet assets. Less reliable vehicles and more unexpected breakdowns can also increase safety risks and negatively impact employee engagement.
- A lack of contingency to address cost pressures in the Fleet Services capital plan associated with exchange rate fluctuations and the adoption of new fleet technologies (e.g. fleet greening).

The following actions will help mitigate the associated risks:

- Telematics IT Project: amongst other benefits, telematics enables right-sizing of the fleet and improved asset utilization, both of which will positively impact the capital plan. This IT project is in Identification Phase presently.
- Cross-functional exploration of opportunities to drive improved asset utilization via reallocation of low-utilization assets, creation of vehicle pools in more locations, etc.
- Updates to vehicle/financial policies (e.g. vehicle assignment criteria, policy re: taking BC Hydro vehicles home), increased cross-functional fleet governance and consistency of practice across departments, and escalation of controllable vehicle damage.
- Completion of two Fleet Category Plans related to fleet asset acquisition will drive increased value from new fleet assets along with improvements in supplier capability/capacity, asset acquisition processes and capital delivery.

Discussion/Information

BOARD BRIEFING – BC HYDRO F2020 - F2024 CAPITAL PLAN

Corporate (Other)

This Portfolio is comprised of capital investments from various departments across BC Hydro, supporting corporate driven initiatives, as well as smaller capital needs from departments such as Security, Safety, Materials Management, Learning, Development & Trades Training, Environment, Engineering, Corporate Affairs, and Site Engineering & Acceptance.

Investments within this portfolio total $55 million in capital additions for F2020-F2024 and include:

- Opportunities to Reduce Electrical Contact Incidents/Minimum Approach Distance – Purchase of additional cover up for distribution crews,
- One Worker Protection System– Developing a one worker protection system by combining Power System Safety Protection and Worker Protection Practices,
- Learning, Development & Trades Training construction of an Energized Training Substation,
- Security investments in physical security requirements for NERC compliance.

Discussion/Information

BOARD BRIEFING – BC HYDRO F2020 - F2024 CAPITAL PLAN

Attachments:

Capital Expenditures & Additions F2020-F2024

F20-F24 Capital Plan

Consolidated by Asset Owner

ESTIMATED CAPITAL EXPENDITURES *	F20	F21	F22	F23	F24	F20-F24 5 Yr Total	F20-F24 5 Yr Avg.
Sustaining							
Generation	337.1	430.3	488.4	534.9	607.0	2,397.6	479.5
Generation - Waneta	4.7	5.2	23.3	8.9	1.7	43.8	8.8
Transmission	222.6	286.5	326.1	329.7	234.6	1,399.5	279.9
Distribution	187.5	176.8	191.2	205.5	207.7	968.7	193.7
Support Services - Technology	95.6	56.0	51.7	53.2	54.8	311.3	62.3
Support Services - Properties	58.9	55.3	37.9	49.0	67.3	268.4	53.7
Support Services - Other & Susidiaries	71.6	83.1	56.0	53.7	58.4	322.8	64.6
Subtotal - Sustaining	978.0	1,093.2	1,174.8	1,234.9	1,231.4	5,712.3	1,142.5
Growth							
Generation	3.2			3.9	13.6	20.7	6.9
Generation - Site C Project	1,530.0	1,535.5	1,317.7	1,003.3	580.5	5,967.0	1,193.4
Generation - Waneta						-	
Transmission	185.0	198.9	372.7	509.0	595.9	1,861.5	372.3
Distribution	300.0	284.6	284.7	260.6	269.7	1,399.6	279.9
Support Services (Powertech)	3.0	3.0	3.0	3.0	3.0	15.0	3.0
Subtotal - Growth	2,021.2	2,022.0	1,978.2	1,779.8	1,462.7	9,263.9	1,852.8
Total before Contribution In Aid (CIA)	2,999.2	3,115.2	3,153.0	3,014.7	2,694.1	14,976.2	2,995.2
Generation - Sustaining	-	-	-	-	-	-	
Generation - Growth	-	-	-	-	-	-	
Transmission - Sustaining	(5.2)	(5.3)	(5.4)	(5.5)	(5.7)	(27.2)	(5.4)
Transmission - Growth	(18.5)	(9.4)	(9.6)	(9.8)	(10.0)	(57.4)	(11.5)
Distribution - Sustaining	(0.8)	(0.8)	(0.8)	(0.9)	(0.9)	(4.1)	(0.8)
Distribution - Growth	(133.3)	(132.9)	(134.3)	(135.7)	(137.1)	(673.3)	(134.7)
CIA Total	(157.8)	(148.5)	(150.2)	(151.9)	(153.7)	(762.1)	(152.4)
Total - including Waneta ($M)	2,841.4	2,966.7	3,002.8	2,862.7	2,540.5	14,214.2	2,842.8
Less: Waneta	(4.7)	(5.2)	(23.3)	(8.9)	(1.7)	(43.8)	(8.8)
Total - excluding Waneta ($M)	2,836.7	2,961.5	2,979.5	2,853.8	2,538.8	14,170.3	2,834.1

ESTIMATED CAPITAL ADDITIONS *	F20	F21	F22	F23	F24		
Generation	310.0	291.7	352.7	401.9	531.4	1,887.7	377.5
Generation - Site C Clean Energy	27.9	189.4			8,625.2	8,842.5	2,947.5
Generation - Waneta	4.7	5.2	23.3	8.9	1.7	43.8	8.8
Transmission	293.8	229.6	479.3	643.0	511.8	2,157.5	431.5
Distribution	502.2	540.7	478.5	470.9	466.7	2,458.9	491.8
Support Services - Technology	147.6	75.5	51.9	53.5	55.1	383.6	76.7
Support Services - Properties	39.9	55.6	57.2	16.4	57.1	226.2	45.2
Support Services - Other & Susidiaries	75.9	82.2	65.0	56.8	61.5	341.5	68.3
						-	
Total before CIA	1,402.0	1,469.9	1,507.9	1,651.5	10,310.5	16,341.7	3,268.3
CIA	(146.1)	(165.8)	(150.6)	(151.8)	(153.5)	(767.9)	(153.6)
Total - including Waneta ($M)	1,255.8	1,304.1	1,357.3	1,499.7	10,157.0	15,573.8	3,114.8
Less: Waneta	(4.7)	(5.2)	(23.3)	(8.9)	(1.7)	(43.8)	(8.8)
Total - excluding Waneta ($M)	1,251.1	1,298.9	1,334.0	1,490.8	10,155.3	15,530.0	3,106.0

* 'Capital Expenditures' are recorded when the costs are incurred. 'Capital Additions' refer to when the related asset is placed into service. Certain costs impacting BC Hydro's revenue requirements, such as amortization, return-on-equity, and finance charges, are not recorded until the related asset is placed into service.

BC Hydro Power smart

Discussion/Information

BOARD BRIEFING – BC HYDRO F2020 - F2024 CAPITAL PLAN

Attachment #2 - Capital Expenditures for Projects Greater than $50M - F2020 to F2024

Projects > $50M with Capital Expenditures Forecasted during F2020 - F2024 ($millions)

Asset Owner	Project	Type	Phase	Forecast ISD	Authorized Amount / Engineering Estimate / Latest Forecast
Generation	Bridge River 1 - Replace Units 1-4 Generators/Governors	Sustaining	Identification	TBD	TBD
Generation	Bridge River 2 - Upgrade Units 5 and 6	Sustaining	Implementation	F2019	$86
Generation	Bridge River 2 - Upgrade Units 7 and 8	Sustaining	Identification	TBD	TBD
Generation	Cheakamus - Dam Improvements	Sustaining	Future	TBD	TBD
Generation	Cheakamus - Units 1 and 2 Generator Replacement	Sustaining	Implementation	F2020	$74
Generation	Clowhom - Unit Upgrade	Sustaining	Future	TBD	TBD
Generation	G.M. Shrum - G1 to 10 Control System Upgrade	Sustaining	Implementation	F2023	$75
Generation	W.A.C. Bennett Dam - Spillway Seismic Upgrade	Sustaining	Future	TBD	TBD
Generation	G.M. Shrum - U1 - U10 Water Passage Refurbishment	Sustaining	Future	TBD	TBD
Generation	W.A.C. Bennett Dam - Rip-Rap Upgrade	Sustaining	In-Service	F2019	$119
Generation	John Hart - Dam Seismic Upgrade	Sustaining	Identification	TBD	TBD
Generation	John Hart - Generating Station Replacement	Sustaining	Implementation	F2019	$985
Generation	Kootenay Canal - U1 - U4 Generators Refurbishment	Sustaining	Future	TBD	TBD
Generation	Lajoie - Dam Improvements	Sustaining	Identification	TBD	TBD
Generation	Ladore - Spillway Seismic Upgrade	Sustaining	Identification	TBD	TBD
Generation	Mica - Discharge Facilities Seismic and Reliability Upgrades	Sustaining	Future	TBD	TBD
Generation	Mica - U1 - U4 Turbine Overhaul	Sustaining	Future	TBD	TBD
Generation	Mica - Reactor 5RX3 and 5RX4 Replacement	Sustaining	Future	TBD	TBD
Generation	Mica - U1 - U4 Circuit Breaker and Iso-phase Bus Replacement	Sustaining	Future	TBD	TBD
Generation	Mica - Replace Units 1 to 4 Generator Transformers	Sustaining	Implementation	F2023	$82
Generation	Revelstoke - Discharge Gate Systems Reliability Improvements	Sustaining	Future	TBD	TBD
Generation	Revelstoke - Install Unit 6	Growth	Definition	F2030	$569 - $317
Generation	Revelstoke - U1 - U4 Stator Replacement	Sustaining	Future	TBD	TBD
Generation	Strathcona - Upgrade Discharge	Sustaining	Identification	TBD	TBD
Generation	Seven Mile - Overhaul Units 1 to 3 Turbines	Sustaining	Identification	TBD	TBD
Generation	Terzaghi - Low-Level Discharge Reliability Improvements	Sustaining	Future	TBD	TBD
Transmission	Peace Region to Kelly Lake 500kV Transmission Reinforcement	Growth	Identification	TBD	TBD
Transmission	Peace Region Electric Supply (PRES)	Growth	Definition	F2022	$348-$197
Transmission	Fort St. John and Taylor Electric Supply	Growth	Implementation	F2021	$53
Transmission	Mount Lehman Substation Upgrade	Growth	Identification	TBD	TBD
Transmission	Kamloops Substation	Growth	In-Service	F2019	$56
Transmission	Horne Payne Substation Upgrade	Growth	Implementation	F2019	$93
Transmission	Northwest Substation Upgrades Project (NSUP)	Growth	Deferred	F2026	TBD
Transmission	Squamish Area Reinforcement	Growth	Identification	TBD	TBD
Transmission	Customer A	Growth	Implementation	F2022	$55
Transmission	Customer C	Growth	Definition	F2022	$102-$72
Transmission	Capilano Substation 25Kv Conversion	Growth	Definition	F2025	$88 - $50
Transmission	Metro North Transmission (MNT)	Growth	Definition	F2025	$530 - $300
Transmission	Langley -Abbotsford - Area Reinforcement	Growth	Future	TBD	TBD
Transmission	West Kelowna Transmission and Westbank Upgrade Projects	Growth	Identification	TBD	TBD
Transmission	5L63 Telkwa Relocation	Sustaining	Identification	TBD	TBD
Transmission	Gulf Islands - Transmission Reinforcement	Sustaining	Future	TBD	TBD
Transmission	Natal Sub - NTL 60-138 kV Rebuild	Sustaining	Identification	TBD	TBD
Transmission	Project A	Growth	Implementation	F2021	$81
Transmission	East Vancouver Substation Construction	Growth	Future	TBD	TBD
Transmission	Metrotown - Property Purchase	Growth	Future	TBD	TBD
Transmission	60L2/3/18 Dewdney Trunk Transmission Copper Conductor Replacement	Sustaining	Future	TBD	TBD
Transmission	West End - Substation Construction and System Reinforcement	Growth	Future	TBD	TBD
Transmission	North Shore Area Transmission Reinforcement	Growth	Identification	TBD	TBD
Transmission	Lower Mainland - Capacitive and Reactive Power Reinforcement	Growth	Future	TBD	TBD
Transmission	2L146 Cable Replacement	Sustaining	Identification	TBD	TBD
Technology	Supply Chain Application	Sustaining	Definition	F2020	$72-$59
Note:	Amounts in the above table are only for capital expenditures on the project.				

Discussion/Information

BOARD BRIEFING – BC HYDRO F2020 - F2024 CAPITAL PLAN

Capital Allocation Risk Matrix (CARM)

BC Hydro CAPITAL ALLOCATION Risk Matrix

FREQUENCY (YEARLY)	FREQUENCY OF CONSEQUENCE		S1	S1.5	S2	S2.5	S3	S3.5	S4	S4.5	S5	S6	S7
f ≥ 100	At least 100 times every year	L9	10		11		12		13		14	15	16
10 ≤ f < 100	At least 10 times every year	L8	9		10		11		12		13	14	15
1 ≤ f < 10	At least once every year	L7	8		9		10		11		12	13	14
1/3 ≤ f < 1	At least once every 3 years	L6.5	7.5	8.0	8.5	9.0	9.5	10.0	10.5	11.0	11	12	13
1/10 ≤ f < 1/3	At least once every 10 years	L6	7.0	7.5	8.0	8.5	9.0	9.5	10.0	10.5			
1/30 ≤ f < 1/10	At least once every 30 years	L5.5	6.5	7.0	7.5	8.0	8.5	9.0	9.5	10.0	10	11	12
1/100 ≤ f < 1/30	At least once every 100 years	L5	6.0	6.5	7.0	7.5	8.0	8.5	9.0	9.5			
1/300 ≤ f < 1/100	At least once every 300 years	L4.5	5.5	6.0	6.5	7.0	7.5	8.0	8.5	9.0	9	10	11
1/1K ≤ f < 1/300	At least once every 1,000 years	L4	5.0	5.5	6.0	6.5	7.0	7.5	8.0	8.5			
1/3K ≤ f < 1/1K	At least once every 3,000 years	L3.5	4.5	5.0	5.5	6.0	6.5	7.0	7.5	8.0	8	9	10
1/10K ≤ f < 1/3K	At least once every 10,000 years	L3	4.0	4.5	5.0	5.5	6.0	6.5	7.0	7.5			
1/100K ≤ f < 1/10K	At least once every 100,000 years	L2	3		4		5		6		7	8	9
1/1M ≤ f < 1/100K	At least once every 1,000,000 years	L1	2		3		4		5		6	7	8

CONSEQUENCE TYPE		CONSEQUENCE SEVERITY										
		S1	S1.5	S2	S2.5	S3	S3.5	S4	S4.5	S5	S6	S7
Safety	Worker	First Aid		Treatment by Medical Professional		Temporary Disability		Permanent Disability		Fatality	Multiple Fatalities	
	Public	Near Miss		First Aid		Treatment by Medical Professional		Temporary Disability		Permanent Disability	Fatality	Multiple Fatalities
Environmental *		Minor		Low		Moderate		High		Extreme	Catastrophic	
Financial Loss		$10K to $30K	$30K to $100K	$100K to $300K	$300K to $1M	$1M to $3M	$3M to $10M	$10M to $30M	$30M to $100M	$100M to $1B	$1B to $10B	> $10B
Reputational *		Limited complaints to company or shareholder		Negative local profile		Small but vocal minority of customers critical		Many customers critical		Loss of trust- strategic change imposed by regulator and/or shareholder	Loss of consent to operate	
Reliability	Supply	N/A		N/A		Require voluntary load reduction		Localized load shedding		Significant load shedding required	BC load shedding spreads to WECC	
	Customer (hours lost per event)	< 1.5K	1.5K to 5K	5K to 15K	15K to 50K	50K to 150K	150K to 500K	500K to 1.5M	1.5M to 5M	5M to 50M	50M to 500M	> 500M

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix I

Capital Expenditures > $5 million

Appendix I Provides Information in Compliance with Commission Order No. G-59-8, Review of the Regulatory Oversight of Capital Expenditures and Projects

Appendix I provides information on non-technology capital projects and programs greater than $5 million and on Technology projects greater than $2 million, with capital expenditures and/or capital additions in fiscal 2020 and fiscal 2021. Consistent with section 9 of Exhibit B-7 (**Revised Proposal)**, filed in the Review of the Regulatory Oversight of Capital Expenditures and Projects, BC Hydro has included the following additional information in Appendix I:

- Project or program planning ID number (column A);
- Descriptive project or program naming (column B). Where applicable, the project or program name will include the following three elements in the order specified below:
    1. **Location:** This is the regional area, line route, or the station, facility, or dam where the primary work is taking place or where the primary asset(s) is situated;
    2. **Asset or Service:** Asset refers to either a component (such as a turbine or transformer) or to a group of related assets (such as a substation or a powerhouse). Service refers to the service to be provided by an information technology project or program; and
    3. **Activity:** Activity refers to the type of primary function or work being performed (e.g., redevelopment, upgrade, or reinforcement).

In addition, Appendix I provides the following information, if applicable:

- Whether the project is a system extension (column T);
- Whether the project will or may be subject to CPCN application or an application under section 44.2 of the *Utilities Commission Act* (column U);
- Whether a relevant Strategy, Plan or Study summary is provided in Appendix K (column W); and
- Whether the project is part of a Program of Projects (column X).

BC Hydro looks for opportunities to combine projects where it can result in efficiencies; however, where projects have different schedules or other practical or technical considerations, they are implemented as separate projects even if in the same facility. In section 5.2 of the Revised Proposal BC Hydro provided clarity on what constitutes a capital project and situations where BC Hydro may combine projects.

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix I

Attachment 1

Capital Project and Programs Information
Fiscal 2020 to Fiscal 2021

PUBLIC

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
Generation			
Hydroelectric			
Growth			
Revelstoke Install Unit 6	1	Page 1	Page 35
Redevelopment / Rehabilitation			
John Hart Generating Station Replacement	2	Page 3	Page 17
Dam Safety			
W.A.C. Bennett Dam Rip-Rap Upgrade	4	Page 5	Page 13
Alouette Improve Headworks & Surge Tower Seismic Stability	5	Page 7	Page 3
Bridge River 1 - Mitigate Surge Spill Hazard	6	N/A	Page 7
Bridge River 1 Improve Slope Drainage	7	N/A	Page 7
Comox - Puntledge Flow Control Improvements	8	Page 9	Page 33
Duncan Dam Replace Spillway Gates	9	Page 11	Page 12
John Hart Dam Seismic Upgrade	10	Page 13	Page 1
Ladore Spillway Seismic Upgrade	11	Page 15	Page 1
Peace Canyon Install Piezometers and Drains in Concrete Dam	12	N/A	Page 29
Revelstoke Improve Left Bank Slope Stability	13	N/A	Page 35
Revelstoke Replace Downie Slide Instrumentation	14	N/A	Page 35
Strathcona Upgrade Discharge	15	Page 17	Page 1
W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates	16	Page 19	Page 13
W.A.C. Bennett Dam Seal Low Level Outlets	17	Page 21	Page 13
Alouette - Environmental Flow Discharge Upgrade and LLO Sealing	18	N/A	Page 3
Hugh Keenleyside - Spillway and Low Level Outlets Concrete Upgrade	19	Page 23	Page 15
Mica - Discharge Facilities Seismic and Reliability Upgrades	20	Page 25	Page 26
Terzaghi - Spillway Chute Access Improvement	21	N/A	Page 7
Sustaining - Other			
Bridge River 2 Upgrade Units 5 and 6	23	Page 27	Page 7

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Cheakamus Replace Units 1 and 2 Turbine Inlet Valves	24	N/A	Page 10
Cheakamus Units 1 and 2 Generator Replacement	25	Page 30	Page 10
G.M. Shrum G1 to Control System Upgrade	26	Page 32	Page 13
G.M. Shrum Replace Unit 1-5 Exciter Transformers	27	N/A	Page 13
Kootenay Canal Upgrade Unit Protection and Install Sequence of Events Recorder	28	N/A	Page 20
Mica Replace Fire Alarm System	29	N/A	Page 26
Mica Replace Units 1 to 4 Generator Transformers	30	Page 34	Page 26
Mica Townsite Augment Accommodations Capacity	31	Page 36	Page 28
Mica Upgrade Powerhouse Cranes	32	Page 37	Page 26
Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)	33	Page 38	Pages 10 and 31
G.M. Shrum Replace / Refurbish 500KV Disconnect Switches	34	N/A	Page 13
G.M. Shrum Upgrade HVAC System	35	Page 40	Page 13
Hugh Keenleyside Replace Service Water Piping	36	N/A	Page 15
Kootenay Canal Upgrade Powerhouse Crane	37	N/A	Page 20
Lake Buntzen 1 - Power House Crane Upgrade	38	N/A	Page 24
Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment	39	Page 41	Page 24
Mica Modernize Controls	40	Page 43	Page 26
Mica Upgrade 600V Circuit Breakers	41	N/A	Page 26
Mica Upgrade HVAC System	42	N/A	Page 26
Peace Canyon Upgrade HVAC System	43	N/A	Page 29
Puntledge Recoat Interior and Exterior of Steel Penstock	44	Page 44	Page 31 and 33
Revelstoke - 600V Circuit Breaker Upgrades	45	N/A	Page 35
Seven Mile Replace Unit 1-4 Exciter Transformers	46	N/A	Page 39
Wahleach Recoat Penstock (Interior and Exterior)	48	Page 46	Page 31 and 44
Wahleach Refurbish Generator	49	Page 48	Page 44
Ash River Extend Life of Steel Penstock	50	N/A	Pages 5 and 31

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Bridge River 1 - Strip and Recoat Penstocks 1-4 Interior	51	Page 49	Pages 7 and 31
Bridge River 1 Replace Units 1-4 Generators / Governors	52	Page 50	Page 7
Bridge River 2 - Strip and Recoat Penstock 2 Interior	53	N/A	Pages 7 and 31
Bridge River 2 Upgrade Units 7 and 8	54	Page 52	Pages 7 and 31
Hugh Keenleyside Recoat Navlock Gates	55	N/A	Page 15
Jordan - Upgrade Governor & PRV Controls	56	N/A	Page 18
Kootenay Canal Modernize Controls	57	Page 54	Page 20
Ladore - Redevelop Unit 1	58	Page 56	Page 22
Ladore Upgrade Protection and Control Systems	59	N/A	Page 22
Lake Buntzen 1 Penstock Exterior Recoat	60	N/A	Page s 24 and 31
Mica - Recoat Intake Maintenance Gates & Draft Tube Maintenance Gates	61	N/A	Page 26
Peace Canyon - 600V Circuit Breaker Upgrades	62	N/A	Page 29
Revelstoke Replace Fire Alarm System	63	N/A	Page 35
Seton - Upgrade Unit	64	Page 57	Page 37
Seven Mile - Replace T1 Transformer	65	N/A	Page 39
Seven Mile Overhaul Units 1 to 3 Turbines	66	Page 59	Page 39
Seven Mile Upgrade Powerhouse Crane Controls	67	N/A	Page 39
Stave Falls - Improve Unit 1&2 Turbine Pitch Assemblies	68	N/A	Page 39
Waneta U3 Life Extension	71	Page 61	N/A
G.M. Shrum - Intake Operating Gate and Intake Maintenance Gate Refurbishment	72	N/A	Page 13
G.M. Shrum - Intake Operating Gate Hydraulic Upgrade	73	Page 63	Page 13
G.M. Shrum - Pauwels Transformer Life Extension	74	N/A	Page 13
G.M. Shrum - Transformers Phase 4 Replacement	75	N/A	Page 13
G.M. Shrum - U1 - U10 Water Passage Refurbishment	76	Page 64	Page 13
G.M. Shrum - U9 - U10 Circuit Breaker Replacement	77	N/A	Page 13

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Lake Buntzen 1 - Generator Replacement	78	Page 65	Page 24
Mica - Intake Gantry Crane Refurbishment	79	N/A	Page 26
Peace Canyon - High and Low Pressure Piping Replacement	80	N/A	Page 29
Peace Canyon - U1 - U4 Exciter Replacement	81	N/A	Page 29
Revelstoke - U1 - U4 Stator Replacement	82	Page 66	Page 35
Seven Mile - U1 - U4 Controls Upgrade	83	N/A	Page 39
Strathcona - G1 Generator Rewind	84	N/A	Page 42
Transmission			
Growth Capital Expenditures			
Regional System Reinforcement			
Fort St. John and Taylor Electric Supply	1	Page 67	N/A
DVES: West End Strategic Property Purchase	2	Page 69	Page 54
Peace Region Electric Supply (PRES)	3	Page 71	Page 75
Metro North Transmission (MNT)	4	Page 73	Page 60
Bridge River Transmission Project	5	Page 75	Page 50
West Kelowna Transmission and Westbank Upgrade Projects	6	Page 77	Page 83
East Vancouver - Substation Construction	7	Page 79	Page 54
West End - Substation Construction and System Reinforcement	8	Page 80	Page 54
Bulk System Reinforcements			
Peace to Kelly Lake Capacitors	9	Page 82	Page 66
Lower Mainland - Capacitive and Reactive Power Reinforcement	10	Page 84	Page 58
Interior to Lower Mainland - Remedial Action Schemes Installation	11	Page 86	N/A
Station Expansion & Modification			
Capilano Substation Upgrade	12	Page 87	Pages 51 and 69
Mount Lehman Substation Upgrade	13	Page 89	Pages 46 and 51
Clayburn Substation Upgrade	14	Page 91	Pages 46 and 51
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Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Pemberton - Substation Upgrade	16	Page 95	N/A
Sustaining Capital Expenditures			
Circuit Breakers			
Copper Conductor Replace - Phase 2	22	N/A	Pages 48 and 51
SPG Metalclad Switchgear Replacement	23	Page 97	Pages 51 and 71
Other Power Equipment			
500kV Capacitor Bank P&C Upgrades	24	N/A	Page 79
Barnard 50/60 Feeder Section Replacement	25	Page 98	Page 48
SC Excitation Systems Upgrade - VIT/KLY	26	N/A	Page 74
Synch Condensor Functional Imp - F17/F18	27	N/A	Page 74
VIT & KLY Hydrogen Gas Sys - Safety Upg	28	N/A	Page 74
BR1 T3 & BRT T4A Replacement	29	Page 99	Page 81
Hundred Mile House T1/T2 EOL Replacement	30	N/A	Page 81
JOR T1 & T2 Replacement	31	Page 101	Page 81
KI1 60Kv Renovatin, 4Kv decommission & control room	32	N/A	Pages 51 and 56
Mainwaring Station Upgrade	33	Page 103	Pages 51 and 59
Natal Sub - NTL 60-138 kV Rebuild	34	Page 105	Page s 51 and 62
Newell Substation Upgrade	35	N/A	Pages 51 and 61
Peace Region to Kelly Lake - Reactor Replacement (Phase 1)	36	Page 107	Page 67
Ah-sin-heek - Substation Replacement	37	N/A	Page 84
Norgate - Substation Upgrade	38	Page 108	Pages 51 and 69
Patricia - Substation Upgrade	39	N/A	Pages 51 and 65
Peace Region to Kelly Lake - Reactor Replacement (Phase 2)	40	Page 107	Page 67
Protection and Control			
NERC CIP V5 Compliance at Medium Impact T&D Stations	41	Page 109	Page 79

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Control PLC984 and RTU Replacement (WSN)	42	N/A	Page 79
Control Systems Upgrade (GMS)	43	N/A	Page 79
Stations Auxiliary Equipment			
Wood Pole Substation Rep - MTE	44	N/A	Page 64
Wood Pole Substation Rep - PSN	45	N/A	Page 64
Stn Service Transfer & AC panels - WSN	46	N/A	Page 81
Wood Pole Substation Rep - BTA	47	N/A	Page 64
Joseph Creek (JOE) Substation Upgrade	48	N/A	Page 64
Woss - Substation Wood Pole Replacement	50	N/A	Page 64
Canal Flats - Substation Wood Pole Replacement	51	N/A	Page 64
Lumby #2 - Substation Wood Pole Replacement	52	N/A	Page 64
Skookumchuck - Substation Wood Pole Replacement	53	N/A	Page 64
Stations Risk Mitigation			
Oil Spill Containment - F17/F18 (ALZ / MDN)	54	N/A	Page 53
Telecommunications			
Vancouver Island Radio System	56	Page 111	Page 78
Underrated Telecom Classifications - NTL	57	N/A	Page 78
CPM MW Repeater Building Rep	58	N/A	Page 78
Fraser Valley - Telecom System Reliability Upgrade	60	N/A	Page 78
Various Sites - Telecom MPLS and DACS Upgrade	61	Page 112	Page 78
Cable Sustainment			
2L146 - Cable Replacement	62	Page 113	Page 77
Gulf Islands - Transmission Reinforcement	63	Page 115	Page 77
O/H Lines Life Extension			
Copper Conductor Replace - Phase 2	64	N/A	Page 76
Circuit Refurbishments - F15 - 2L13/14	65	N/A	Page 86
5L63 Telkwa Relocation	66	Page 118	N/A
2L048 - Long Span Crossing Refurbishment	67	N/A	Page 76
Distribution			
Sustaining Capital Expenditures			
System Expansion and Improvement			
H-Frame Elimination - Chinatown	21	Page 118	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
New DGR Circuit for Customer Vaults at Pacific and Howe (LM-VAN-004)	23	N/A	54
New DGR Circuit for Customer Vaults at Drake and Howe (LM-VAN-005)	24	N/A	54
Various Sites - LED Street Light Conversion	26	Page 120	Page 88
Technology			
Enhance Business Capability			
Projects Over $2 million			
Supply Chain Applications	25	Page 121	N/A
Other			
Properties			
Chilliwack Field Building Redevelopment	4	Page 123	N/A
Materials Classification Facility Building Redevelopment	5	Page 125	N/A
Kamloops Field Building Redevelopment	6	Page 127	N/A
Other Capital			
Project B (Property)	11	Page 93	Page 72

Appendix I - F2020 - F2021 RRA - Generation
Projects and Programs greater than $5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F20-F21) as at April 1, 2018 (1), (2)

$ Million

	A	B	C	D	H	I	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Authorized Amount (9)	Capital Addition Actual F18	Capital Addition Forecast F19	Capital Addition Forecast F20	Capital Addition Forecast F21	Capital Expenditure Actual F18	Capital Expenditure Forecast F19	Capital Expenditure Forecast F20	Capital Expenditure Forecast F21	Extension Project, Y=Yes, N= No	Current or Potential Application (11)	Appendix J Reference	Name for Appendix K Reference (Summaries of Strategies, Plans & Studies)	Appendix K Reference	Program of Projects
Generation																					
		Hydroelectric																			
		Growth																			
1	G000594	Revelstoke Install Unit 6	Growth	Definition					-	-	-	3.7	2.2	0.6	-	Y	Exempt per section 7 of Clean Energy Act	Page 1	Revelstoke Facility Asset Plan	Page 35	
		Redevelopment / Rehabilitation																			
2	G000597	John Hart Generating Station Replacement	Sustaining	Implementation	1,092.9	F2019	1,092.9		955.8	23.2	-	211.6	71.6	23.1	-	Y	Approved CPCN per Order C-2-13	Page 3	John Hart Facility Asset Plan	Page 17	
3	G003085	Project A	Sustaining	Implementation	[redacted]	F2019	[redacted]		-	[redacted]	-	-	-	[redacted]	-	N					
		Dam Safety																			
4	G000656	W.A.C. Bennett Dam Spillway Gate Upgrade	Sustaining	Implementation	47.5	F2020	47.5		6.9	25.9	8.2	1.2	16.0	9.0	8.2	N		Page 5	G.M. Shrum Facility Asset Plan	Page 13	
5	G000011	Alouette Improve Headworks & Surge Tower Seismic Stability	Sustaining	Identification					-	-	-	0.8	1.3	1.5	5.4	N		Page 7	Alouette Facility Asset Plan	Page 3	
6	G003852	Bridge River 1 - Mitigate Surge Spill Hazard	Sustaining	Identification					-	4.9	0.1	-	0.3	4.6	0.1	N			Bridge River Facility Asset Plan	Page 7	
7	G003467	Bridge River 1 Improve Slope Drainage	Sustaining	Identification					-	8.2	-	0.1	0.5	7.1	-	N			Bridge River Facility Asset Plan	Page 7	
8	G000657	Comox - Puntledge Flow Control Improvements (Note b)	Sustaining	Identification					-	-	-	1.5	2.1	6.5	17.2	N		Page 9	Puntledge Facility Asset Plan	Page 33	
9	G000755	Duncan Dam Replace Spillway Gates	Sustaining	Identification					-	-	-	-	-	0.2	2.3	N		Page 11	Duncan Dam Facility Asset Plan	Page 12	
10	G000585	John Hart Dam Seismic Upgrade	Sustaining	Identification					-	-	-	6.0	5.7	9.2	19.5	N	Potential CPCN or s44.2	Page 13	Campbell River Study	Page 1	
11	G000668	Ladore Spillway Seismic Upgrade	Sustaining	Identification					-	-	-	0.7	2.1	1.9	2.9	N	Potential CPCN or s44.2	Page 15	Campbell River Study	Page 1	
12	G003127	Peace Canyon Install Piezometers and Drains in Concrete Dam	Sustaining	Identification					-	-	-	-	-	0.3	1.0	N			Peace Canyon Facility Asset Plan	Page 29	
13	G000246	Revelstoke Improve Left Bank Slope Stability	Sustaining	Identification					-	-	11.5	0.1	0.3	3.9	7.3	N			Revelstoke Facility Asset Plan	Page 35	
14	G003129	Revelstoke Replace Downie Slide Instrumentation	Sustaining	Identification					-	-	-	-	0.3	1.2	3.3	N			Revelstoke Facility Asset Plan	Page 35	
15	G000525	Strathcona Upgrade Discharge	Sustaining	Identification					-	-	-	2.6	3.4	7.1	19.3	N	Potential CPCN or s44.2	Page 17	Campbell River Study	Page 1	
16	G003554	W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates	Sustaining	Identification					-	-	-	-	0.2	0.5	10.7	N		Page 19	G.M. Shrum Facility Asset Plan	Page 13	
17	G003555	W.A.C. Bennett Dam Seal Low Level Outlets	Sustaining	Identification					-	-	-	-	0.6	0.9	3.8	N		Page 21	G.M. Shrum Facility Asset Plan	Page 13	
18	G000001	Alouette - Environmental Flow Discharge Upgrade and LLO Sealing	Sustaining	Future					-	-	-	-	-	0.2	2.2	N			Alouette Facility Asset Plan	Page 3	
19	G000556	Hugh Keenleyside - Spillway and Low Level Outlets Concrete Upgrade	Sustaining	Future					-	-	-	-	-	-	1.1	N		Page 23	Hugh Keenleyside Facility Asset Plan	Page 15	
20	G003365	Mica - Discharge Facilities Seismic and Reliability Upgrades	Sustaining	Future					-	-	-	-	-	-	2.2	N		Page 25	Mica Facility Asset Plan	Page 26	
21	G000467	Terzaghi - Spillway Chute Access Improvement	Sustaining	Future					-	-	12.0	-	-	1.2	10.8	N			Bridge River Facility Asset Plan	Page 7	
22	G003653	Various Sites - Reservoir Booms Replacement - F2020	Sustaining	Future					-	-	5.9	-	-	1.0	5.6	N					
		Sustaining - Other																			
23	G000492	Bridge River 2 Upgrade Units 5 and 6	Sustaining	Implementation	86.2	F2019	86.2		64.1	2.8	8.7	13.0	41.7	2.8	8.7	N		Page 27	Bridge River Facility Asset Plan	Page 7	
24	G000571	Cheakamus Replace Units 1 and 2 Turbine Inlet Valves	Sustaining	Implementation	10.7	F2020	12.4		-	2.9	7.3	1.4	2.6	2.7	0.8	N			Cheakamus Facility Asset Plan	Page 10	
25	G000614	Cheakamus Units 1 and 2 Generator Replacement	Sustaining	Implementation	74.2	F2020	74.2		25.8	32.4	5.2	17.8	14.0	11.0	5.2	N		Page 30	Cheakamus Facility Asset Plan	Page 10	
26	G000127	G.M. Shrum G1 to 10 Control System Upgrade	Sustaining	Implementation	75.0	F2022	75.0	2.2	15.5	6.0	21.0	10.5	9.5	15.1	9.5	N		Page 32	G.M. Shrum Facility Asset Plan	Page 13	
27	G000121	G.M. Shrum Replace Unit 1-5 Exciter Transformers	Sustaining	Implementation	9.3	F2020	9.3		2.1	4.9	0.8	0.3	3.6	2.7	0.8	N			G.M. Shrum Facility Asset Plan	Page 13	
28	G000374	Kootenay Canal Upgrade Unit Protection and Install Sequence of Events Recorder	Sustaining	Implementation	7.8	F2020	7.8		3.6	3.8	-	3.7	2.4	0.3	-	N			Kootenay Canal Facility Asset Plan	Page 20	
29	G000789	Mica Replace Fire Alarm System	Sustaining	Implementation	8.5	F2020	8.5		-	7.5	-	0.2	5.0	2.0	-	N			Mica Facility Asset Plan	Page 26	
30	G003207	Mica Replace Units 1 to 4 Generator Transformers	Sustaining	Implementation	82.1	F2023	82.1		-	12.1	12.3	2.9	9.5	15.3	12.9	N		Page 34	Mica Facility Asset Plan	Page 26	
31	G003362	Mica Townsite Augment Accommodations Capacity	Sustaining	Implementation	23.3	F2020	23.3		-	20.5	1.5	5.6	7.2	2.8	1.5	N		Page 36	Mica Townsite Facility Asset Plan	Page 28	
32	G003542	Mica Upgrade Powerhouse Cranes	Sustaining	Implementation	36.1	F2020	36.1		-	26.8	0.4	3.8	11.0	3.4	0.4	N		Page 37	Mica Facility Asset Plan	Page 26	
33	G000057	Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)	Sustaining	Definition					-	-	31.5	0.3	1.7	5.8	23.3	N		Page 38	Cheakamus Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Pages 10 and 31	
34	G000135	G.M. Shrum Replace / Refurbish 500KV Disconnect Switches	Sustaining	Definition					-	-	-	0.2	1.0	2.7	1.6	N			G.M. Shrum Facility Asset Plan	Page 13	
35	G000114	G.M. Shrum Upgrade HVAC System	Sustaining	Definition					-	-	-	0.3	0.1	1.4	15.9	N		Page 40	G.M. Shrum Facility Asset Plan	Page 13	
36	G000747	Hugh Keenleyside Replace Service Water Piping	Sustaining	Definition					-	-	8.8	0.2	0.3	6.9	1.2	N			Hugh Keenleyside Facility Asset Plan	Page 15	
37	G000962	Kootenay Canal Upgrade Powerhouse Crane	Sustaining	Definition					-	8.8	-	0.3	1.2	7.1	-	N			Kootenay Canal Facility Asset Plan	Page 20	
38	G000165	Lake Buntzen 1 - Power House Crane Upgrade	Sustaining	Definition					-	6.9	-	0.3	1.4	5.2	-	N			Coquitlam-Buntzen System Facility Asset Plan	Page 24	
39	G000640	Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment	Sustaining	Definition					-	-	-	0.7	1.7	1.7	7.7	N		Page 41	Coquitlam-Buntzen System Facility Asset Plan	Page 24	
40	G000172	Mica Modernize Controls	Sustaining	Definition					-	4.4	4.5	0.8	6.3	8.8	8.6	N		Page 43	Mica Facility Asset Plan	Page 26	

	A	B	C	D	H	I	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Authorized Amount (9)	Capital Addition Actual F18	Capital Addition Forecast F19	Capital Addition Forecast F20	Capital Addition Forecast F21	Capital Expenditure Actual F18	Capital Expenditure Forecast F19	Capital Expenditure Forecast F20	Capital Expenditure Forecast F21	Extension Project, Y=Yes, N= No	Current or Potential Application (11)	Appendix J Reference	Name for Appendix K Reference (Summaries of Strategies, Plans & Studies)	Appendix K Reference	Program of Projects
41	G003456	Mica Upgrade 600V Circuit Breakers	Sustaining	Definition					0.9	4.4	12.0	0.5	2.0	5.4	9.2	N			Mica Facility Asset Plan	Page 26	
42	G000801	Mica Upgrade HVAC System	Sustaining	Definition					-	-	12.6	0.3	0.4	2.4	9.4	N			Mica Facility Asset Plan	Page 26	
43	G000219	Peace Canyon Upgrade HVAC System	Sustaining	Definition					-	-	-	0.3	-	1.0	2.2	N			Peace Canyon Facility Asset Plan	Page 29	
44	G000241	Puntledge Recoat Interior and Exterior of Steel Penstock	Sustaining	Definition					-	-	1.3	0.4	0.4	7.9	6.1	N		Page 44	Puntledge Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Pages 31 and 33	
45	G001008	Revelstoke - 600V Circuit Breaker Upgrades	Sustaining	Definition					-	-	-	0.2	0.2	0.6	5.5	N			Revelstoke Facility Asset Plan	Page 35	
46	G000792	Seven Mile Replace Unit 1-4 Exciter Transformers	Sustaining	Definition					-	-	8.6	0.3	0.5	4.0	3.7	N			Seven Mile Facility Asset Plan	Page 39	
47	G003515	Various - Water License Renewal	Sustaining	Definition					-	-	5.3	1.7	1.8	0.8	0.6	N					
48	G000342	Wahleach Recoat Penstock (Interior and Exterior)	Sustaining	Definition					-	-	26.0	0.3	1.0	4.6	19.7	N		Page 46	Wahleach Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Pages 31 and 44	
49	G000334	Wahleach Refurbish Generator	Sustaining	Definition					-	-	-	1.8	3.7	6.3	5.5	N		Page 48	Wahleach Facility Asset Plan	Page 44	
50	G000042	Ash River Extend Life of Steel Penstock	Sustaining	Identification					-	-	-	-	-	0.3	0.7	N			Ash River Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Pages 5 and 31	
51	G000485	Bridge River 1 - Strip and Recoat Penstocks 1-4 Interior	Sustaining	Identification					-	-	-	-	0.6	3.0	4.7	N		Page 49	Bridge River Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Pages 7 and 31	
52	G000776	Bridge River 1 Replace Units 1-4 Generators / Governors	Sustaining	Identification					-	-	-	1.3	1.8	3.7	10.5	N	Potential s44.2	Page 50	Bridge River Facility Asset Plan	Page 7	
53	G000489	Bridge River 2 - Strip and Recoat Penstock 2 Interior	Sustaining	Identification					-	-	16.6	-	0.6	3.1	13.0	N			Bridge River Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Pages 7 and 31	
54	G000493	Bridge River 2 Upgrade Units 7 and 8	Sustaining	Identification					-	-	54.7	0.4	1.7	11.5	41.1	N		Page 52	Bridge River Facility Asset Plan	Page 7	
55	G003035	Hugh Keenleyside Recoat Navlock Gates	Sustaining	Identification					-	-	-	0.2	0.2	0.3	4.4	N			Hugh Keenleyside Facility Asset Plan	Page 15	
56	G000158	Jordan - Upgrade Governor & PRV Controls	Sustaining	Identification					-	-	-	0.2	0.4	2.4	5.1	N			Jordan River Facility Asset Plan	Page 18	
57	G000952	Kootenay Canal Modernize Controls	Sustaining	Identification					-	-	-	-	-	0.2	7.6	N		Page 54	Kootenay Canal Facility Asset Plan	Page 20	
58	G000741	Ladore - Redevelop Unit 1	Sustaining	Identification					-	-	-	-	-	0.6	3.3	N		Page 56	Ladore Falls Facility Asset Plan	Page 22	
59	G000517	Ladore Upgrade Protection and Control Systems	Sustaining	Identification					-	-	-	-	-	0.1	0.3	N			Ladore Falls Facility Asset Plan	Page 22	
60	G000169	Lake Buntzen 1 Penstock Exterior Recoat	Sustaining	Identification					-	-	-	-	-	0.5	0.9	N			Coquitlam-Buntzen System Facility Asset Plan Generation Asset Management Strategy - Penstock Recoating	Pages 24 and 31	
61	G000174	Mica - Recoat Intake Maintenance Gates & Draft Tube Maintenance Gates	Sustaining	Identification					-	-	4.3	0.1	0.4	1.7	2.1	N			Mica Facility Asset Plan	Page 26	
62	G000220	Peace Canyon - 600V Circuit Breaker Upgrades	Sustaining	Identification					-	-	-	-	0.4	1.9	0.8	N			Peace Canyon Facility Asset Plan	page 29	
63	G003373	Revelstoke Replace Fire Alarm System	Sustaining	Identification					-	-	-	-	0.2	2.6	5.7	N			Revelstoke Facility Asset Plan	Page 35	
64	G003026	Seton - Upgrade Unit	Sustaining	Identification					-	-	-	-	-	0.6	4.5	N		Page 57	Seton Facility Asset Plan	Page 37	
65	G000834	Seven Mile - Replace T1 Transformer	Sustaining	Identification					-	-	-	-	-	0.6	1.6	N			Seven Mile Facility Asset Plan	Page 39	
66	G000796	Seven Mile Overhaul Units 1 to 3 Turbines	Sustaining	Identification					-	-	-	0.7	0.7	2.1	2.1	N	Potential CPCN or s44.2	Page 59	Seven Mile Facility Asset Plan	Page 39	
67	G000822	Seven Mile Upgrade Powerhouse Crane Controls	Sustaining	Identification					-	-	-	-	-	0.4	3.2	N			Seven Mile Facility Asset Plan	Page 39	
68	G003755	Stave Falls - Improve Unit 1&2 Turbine Pitch Assemblies	Sustaining	Identification					-	-	-	-	-	0.2	1.6	N			Stave Falls Facility Asset Plan	Page 39	
69	G003422	Various - Remediate PCB Contaminated Equipment	Sustaining	Identification					-	-	-	-	-	1.3	2.6	N					
70	G003449	Various Facilities Replace Water Level Gauges	Sustaining	Identification					-	-	-	-	0.2	0.3	1.1	N					
71	G001047	Waneta U3 Life Extension	Sustaining	Identification					-	-	-	-	0.4	3.4	3.1	N		Page 61			
72	G000131	G.M. Shrum - Intake Operating Gate and Intake Maintenance Gate Refurbishment	Sustaining	Future					-	-	-	-	-	-	0.3	N			G.M. Shrum Facility Asset Plan	Page 13	
73	G003336	G.M. Shrum - Intake Operating Gate Hydraulic Upgrade	Sustaining	Future					-	-	-	-	-	-	0.4	N		Page 63	G.M. Shrum Facility Asset Plan	Page 13	
74	G003826	G.M. Shrum - Pauwels Transformer Life Extension	Sustaining	Future					-	-	-	-	-	-	0.1	N			G.M. Shrum Facility Asset Plan	Page 13	
75	G000133	G.M. Shrum - Transformers Phase 4 Replacement	Sustaining	Future					-	-	-	-	-	0.7	3.0	N			G.M. Shrum Facility Asset Plan	Page 13	
76	G000130	G.M. Shrum - U1 - U10 Water Passage Refurbishment	Sustaining	Future					-	-	-	-	-	-	0.7	N		Page 64	G.M. Shrum Facility Asset Plan	Page 13	
77	G000120	G.M. Shrum - U9 - U10 Circuit Breaker Replacement	Sustaining	Future					-	-	-	-	-	0.2	0.3	N			G.M. Shrum Facility Asset Plan	Page 13	
78	G000168	Lake Buntzen 1 - Generator Replacement	Sustaining	Future					-	-	-	-	-	-	1.8	N		Page 65	Coquitlam-Buntzen System Facility Asset Plan	Page 24	
79	G000195	Mica - Intake Gantry Crane Refurbishment	Sustaining	Future					-	-	-	-	-	0.6	4.1	N			Mica Facility Asset Plan	Page 26	
80	G000231	Peace Canyon - High and Low Pressure Piping Replacement	Sustaining	Future					-	-	-	-	-	-	0.4	N			Peace Canyon Facility Asset Plan	Page 29	
81	G003835	Peace Canyon - U1 - U4 Exciter Replacement	Sustaining	Future					-	-	-	-	-	-	0.4	N			Peace Canyon Facility Asset Plan	Page 29	
82	G000252	Revelstoke - U1 - U4 Stator Replacement	Sustaining	Future					-	-	-	-	-	-	1.2	N	Potential s44.2	Page 66	Revelstoke Facility Asset Plan	Page 35	
83	G000436	Seven Mile - U1 - U4 Controls Upgrade	Sustaining	Future					-	-	-	-	-	0.3	1.1	N			Seven Mile Facility Asset Plan	Page 39	
84	G001918	Strathcona - G1 Generator Rewind	Sustaining	Future					-	-	-	-	-	-	2.2	N			Strathcona Facility Asset Plan	Page 42	
		Add: Projects Less than $5M								73.4	78.1			87.8	72.2						
		TOTAL Hydroelectric								**294.1**	**359.7**			**341.7**	**491.1**						

	A	B	C	D	H	I	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Phase (3)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Authorized Amount (9)	Capital Addition Actual F18	Capital Addition Forecast F19	Capital Addition Forecast F20	Capital Addition Forecast F21	Capital Expenditure Actual F18	Capital Expenditure Forecast F19	Capital Expenditure Forecast F20	Capital Expenditure Forecast F21	Extension Project, Y=Yes, N= No	Current or Potential Application (11)	Appendix J Reference	Name for Appendix K Reference (Summaries of Strategies, Plans & Studies)	Appendix K Reference	Program of Projects
		Diesel																			
		Add: Projects & Programs Less than $5M								7.9	5.8			8.7	5.0						
		TOTAL Diesel								**7.9**	**5.8**			**8.7**	**5.0**						
		Thermal																			
		Add: Projects & Programs Less than $5M								3.8	6.1			6.6	4.5						
		TOTAL Thermal								**3.8**	**6.1**			**6.6**	**4.5**						
		Generation Total								**305.8**	**371.5**			**357.0**	**500.6**						
		Portfolio Delivery Adjustment								**8.9**	**(74.6)**			**(11.9)**	**(65.2)**						
		Total								**314.7**	**297.0**			**345.1**	**435.5**						

Note a: Given the nature of the project, a definition phase was not undertaken.

Note b: In the F17-F19 RRA, the Name of this Project was Puntledge Flow Control Improvements.

Notes:

(1) Information provided is current as of the established 'Currency Date' which is April 1, 2018. Information for certain projects in progress has been updated for significant events subsequent to this date.

(2) Some projects that are in service or forecast to be in service at the end of fiscal 2019 may have trailing expenditures that result in capital additions in the test period. These expenditures and associated capital additions have been aggregated and included in the line item "Projects less than $5 million".

(3) Project / Program dollars are generally capitalized starting either in the feasibility stage of Identification phase or in the Definition phase.

(4) Forecast ISD is the expected in-service date (as at the Currency Date) when the project goes into service.

(5) Start Date of Construction is the Implementation Approval Date. For projects in Definition, the Start of Construction is the forecasted Implementation approval date.

(6) Fiscal Year that the project received Definition phase approval.

(7) Implementation Approval $ refers to the 'Authorized' total capital cost of the project when it was first approved by BC Hydro for Implementation.

(8) Pre-Implementation phases are: Future, Identification and Definition. See Chapter 6, section 6.4.7.4 to 6.4.7.7 for further discussion on pre-Implementation phases. Pre-Implementation cost estimates are provided where an engineering estimate is available. Engineering estimates are generally completed during the mid-stage of Identification phase. N/A indicates that an engineering estimate is not yet available, or that the project is in Implementation phase.

(9) Amounts reflect only the capital portion of the Authorized amount.

(10) Implementation Approval ISD refers to the in-service date identified when the project was first approved by BC Hydro for Implementation.

(11) Project meets the current threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate as of the Currency Date (See Note 1), or in accordance with BCUC Direction No. G-47-18.

Use of To Be Determined (TBD):

For projects in Future or Identification phase, To be Determined (TBD) is provided for the Pre Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start Date of Construction, for the following reasons:

For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In Identification phase, a number of identified alternative responses are being investigated, and each alternative can result in very different project scope, schedule and cost. As a result, Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start of Construction Date are generally only provided for projects in the Definition phase and later phases.

Appendix I - F2020 - F2021 RRA - Transmission
Projects and Programs greater than $5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F20-F21) as at April 1, 2018 (1), (2)
$ Million

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Stage (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F18	Capital Addition Forecast F19	Capital Addition Forecast F20	Capital Addition Forecast F21	Capital Expenditure Actual F18	Capital Expenditure Forecast F19	Capital Expenditure Forecast F20	Capital Expenditure Forecast F21	Extension Project, Y=Yes, N= No	Current or Potential Application (11)	Appendix J Reference	Name for Appendix K Reference (Summaries of Strategies, Plans & Studies)	Appendix K Reference	Program of Projects
Transmission																									
		Growth Capital Expenditures																							
		Regional System Reinforcement																							
1	92525	Fort St. John and Taylor Electric Supply	Growth	Implementation	F2021	F2016	Note a	53.1	F2020	N/A - In Implementation	53.1	-	-	-	53.4	4.7	23.8	21.1	3.2	Y		Page 67			
2	900219	DVES: West End Strategic Property Purchase	Growth	Implementation	F2021	F2019	Note b	80.7	F2021	N/A - In Implementation	80.7	-	-	80.7	0.0	-	77.7	3.0	0.0	Y		Page 69	Downtown Vancouver Electric Supply Plan	Page 54	
3	92216	Peace Region Electric Supply (PRES)	Growth	Definition	F2022	F2019	F2017	-		348.0 - 197.0	-	-	-	-	-	10.7	37.4	66.1	56.2	Y	Exempt Project, M216,OIC 101	Page 71	Transmission Planning Study Peace Region Electric Supply Project	Page 75	
4	93845	Metro North Transmission (MNT)	Growth	Definition	F2025	TBD	F2017	-		530.0 - 300.0	-	-	-	-	-	3.9	0.2	-	1.0	Y	CPCN	Page 73	Metro North Transmission Planning Report	Page 60	
5	92423	Bridge River Transmission Project	Growth	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	1.7	7.5	Y		Page 75	Bridge River Transmission System Upgrade - NITS Study	Page 50	
6	94034	West Kelowna Transmission and Westbank Upgrade Projects	Growth	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	3.6	8.5	6.8	9.4	Y	CPCN	Page 77	West Kelowna Area Study	Page 83	
7	900266	East Vancouver - Substation Construction	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	3.8	9.1	Y	CPCN	Page 79	Downtown Vancouver Electric Supply Plan	Page 54	
8	900598	West End - Substation Construction and System Reinforcement	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	-	2.7	Y	CPCN	Page 80	Downtown Vancouver Electric Supply Plan	Page 54	
		Bulk System Reinforcements																							
9	90957	Peace to Kelly Lake Capacitors	Growth	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	0.1	11.5	41.1	Y	CPCN	Page 82	Study	Page 66	
10	900992	Lower Mainland - Capacitive and Reactive Power Reinforcement	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	-	0.4	Y		Page 84	Burrard Synchronous Condensers Replacement Study	Page 58	
11	901251	Interior to Lower Mainland - Remedial Action Schemes Installation	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	-	0.8	N		Page 86			
		Station Expansion & Modification																							
12	93788	Capilano Substation Upgrade	Growth	Definition	F2025	F2020	F2018	-		88.0 - 50.0	-	-	-	-	-	1.3	1.9	1.9	6.0	Y		Page 87	Integrated Planning Report for Capilano and Lynn Valley Substations and Distribution Area Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 51 and 69	
13	92907	Mount Lehman Substation Upgrade	Growth	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.6	1.3	7.3	9.6	Y		Page 89	Abbotsford Area Study Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 46 and 51	
14	92910	Clayburn Substation Upgrade	Growth	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.1	0.3	1.5	5.2	Y		Page 91	Abbotsford Area Study Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 46 and 51	
15	93632	Project B (Substation)	Growth	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	0.2	0.0	Y		Page 93	[redacted]	Page 72	
16	900816	Pemberton - Substation Upgrade	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	-	0.5	Y		Page 95			
		Generator Interconnections																							
17	900626	Bremner-Trio Hydro Project (Note c)	Growth	Implementation	F2020	F2018	F2018	7.9	F2019	N/A - In Implementation	7.9	-	-	-	7.3	0.3	2.1	4.1	0.7	Y					
		Transmission Load Interconnections																							
18	94003	UBC Load Increase Stage 2	Growth	Implementation	F2022	F2018	F2016	55.2	F2022	N/A - In Implementation	55.2	-	-	-	-	2.8	4.2	17.8	15.0	Y					
19	900861	Customer A	Growth	Implementation	F2020	F2018	F2018	5.8	F2019	N/A - In Implementation	5.8	-	-	4.6	0.4	0.5	0.9	3.2	0.4	Y					
20	93786	Customer B	Growth	Definition	F2022	F2020	F2016	-		102.0 - 72.0	-	-	-	-	-	-	5.8	28.2	26.6	Y					
21	900836	Customer C	Growth	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	15.3	-	2.2	8.9	4.3	Y					
		Add: Projects Less than $5M												12.6	8.8			10.1	9.2						
		TOTAL Gross Growth Capital Additions												**97.9**	**85.3**			**197.2**	**208.9**						
		Less: Contributions in Aid of Construction												(10.2)	(20.5)			(18.5)	(9.4)						
		Net Growth Capital Additions												**87.7**	**64.8**			**178.7**	**199.5**						
		Sustaining Capital Expendiutres																							
		Circuit Breakers																							
22	900765	BND 60kV CB and Relay Building Replacement	Sustaining	Implementation	F2020	F2018	F2017	16.4	F2020	N/A - In Implementation	16.4	-	-	12.5	0.1	7.6	3.0	0.9	0.1	N			Barnard Asset Plan Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 48 and 51	
23	900243	SPG Metalclad Switchgear Replacement	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.4	1.2	2.4	17.2	N		Page 97	Sperling Asset Plan Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 51 and 71	
		Other Power Equipment																							
24	92073	500kV Capacitor Bank P&C Upgrades (Note c)	Sustaining	Definition	F2021	F2019	F2018	-		TBD	-	-	-	-	-	0.2	3.6	4.4	2.8	N			Asset Management Strategy - Section 2.4.4: Protection & Control Equipment	Page 79	
25	900575	Barnard 50/60 Feeder Section Replacement	Sustaining	Definition	F2022	F2019	F2018	-		66.0 - 37.4	-	-	-	-	-	1.9	2.1	7.2	12.1	N		Page 98	Barnard Asset Plan	Page 48	
26	92166	SC Excitation Systems Upgrade - VIT/KLY	Sustaining	Definition	F2022	F2019	F2014	-		N/A	-	-	-	-	-	0.2	0.8	1.9	1.9	N			Asset Management Strategy - Section 2.2.15: Synchronous Condensers	Page 74	
27	93700	Synch Condensor Functional Imp - F17/F18	Sustaining	Definition	F2022	F2019	F2017	-		N/A	-	-	-	-	-	0.2	1.4	2.7	2.8	N			Asset Management Strategy - Section 2.2.15: Synchronous Condensers	Page 74	
28	92618	VIT & KLY Hydrogen Gas Sys - Safety Upg	Sustaining	Definition	F2022	F2019	F2017	-		N/A	-	-	-	-	-	0.4	0.7	1.7	1.8	N			Asset Management Strategy - Section 2.2.15: Synchronous Condensers	Page 74	
29	900247	BR1 T3 & BRT T4A Replacement	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	18.8	0.5	0.8	2.4	15.2	Y		Page 99	Asset Management Strategy - Section 2.2.16: Power Transformers	Page 81	
30	900564	Hundred Mile House T1/T2 EOL Replacement	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	0.3	0.7	2.7	Y			Asset Management Strategy - Section 2.2.16: Power Transformers	Page 81	
31	93731	JOR T1 & T2 Replacement	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.3	0.8	7.8	14.7	N		Page 101	Asset Management Strategy - Section 2.2.16: Power Transformers	Page 81	
32	93705	KI1 60Kv Renovatin, 4Kv decommission & control room	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	0.5	0.8	2.0	N			Kidd 1 Asset Plan Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 51 and 56	
33	92478	Mainwaring Station Upgrade	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.5	1.1	5.1	5.7	Y	CPCN	Page 103	Mainwaring Asset Plan Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 51 and 59	
34	900152	Natal Sub - NTL 60-138 kV Rebuild	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.3	0.4	0.8	1.4	N		Page 105	Natal Asset Plan Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 51 and 62	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Stage (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F18	Capital Addition Forecast F19	Capital Addition Forecast F20	Capital Addition Forecast F21	Capital Expenditure Actual F18	Capital Expenditure Forecast F19	Capital Expenditure Forecast F20	Capital Expenditure Forecast F21	Extension Project, Y=Yes, N= No	Current or Potential Application (11)	Appendix J Reference	Name for Appendix K Reference (Summaries of Strategies, Plans & Studies)	Appendix K Reference	Program of Projects
35	92479	Newell Substation Upgrade	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	0.1	0.6	2.5	N			Newell Asset Plan Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 51 and 61	
36	900884	Peace Region to Kelly Lake - Reactor Replacement (Phase 1) (Note d)	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	0.3	3.6	9.3	-	0.4	4.4	10.5	N		Page 107	Asset Management Strategy - Section 2.2.10: Shunt Reactors	Page 67	Y
37	94081	Ah-sin-heek - Substation Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	0.1	2.1	Y			Wood Pole Substation Strategy	Page 84	
38	901034	Norgate - Substation Upgrade	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	-	0.5	Y		Page 108	Integrated Planning Report for Capilano and Lynn Valley Substations and Distribution Area Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 51 and 69	
39	92759	Patricia - Substation Upgrade	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	0.3	5.9	Y			Patricia Asset Plan Asset Management Strategy - Section 2.2.2: Circuit Breakers	Pages 51 and 65	
40	900185	Peace Region to Kelly Lake - Reactor Replacement (Phase 2) (Note d)	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	0.6	-	-	-	0.7	N		Page 107	Asset Management Strategy - Section 2.2.10: Shunt Reactors	Page 67	Y
		Protection and Control																							
41	900625	NERC CIP v5 Compliance at Medium Impact T&D Stations	Sustaining	Definition	F2023	F2019	F2018	-		31.2 - 17.7	-	-	-	-	-	4.0	10.5	3.4	3.5	N		Page 109	Asset Management Strategy - Section 2.4.4: Protection & Control Equipment	Page 79	
42	900250	Control PLC984 and RTU Replacement (WSN)	Sustaining	Definition	F2022	F2019	F2017	-		6.9 - 5.4	-	-	-	-	-	0.1	0.3	3.1	1.7	N			Asset Management Strategy - Section 2.4.4: Protection & Control Equipment	Page 79	
43	93687	Control Systems Upgrade (GMS)	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	0.2	0.6	3.2	N			Asset Management Strategy - Section 2.4.4: Protection & Control Equipment	Page 79	
		Stations Auxiliary Equipment																							
44	900787	Wood Pole Substation Rep - MTE	Sustaining	Implementation	F2020	F2018	F2017	6.0	F2020	N/A - In Implementation	6.0	-	-	5.3	-	0.1	2.1	2.9	-	Y			Wood Pole Substation Strategy	Page 64	
45	900788	Wood Pole Substation Rep - PSN	Sustaining	Implementation	F2020	F2018	F2017	5.8	F2020	N/A - In Implementation	5.8	-	-	5.2	-	0.1	2.4	2.6	-	Y			Wood Pole Substation Strategy	Page 64	
46	93690	Stn Service Transfer & AC panels - WSN (Note c)	Sustaining	Implementation	F2019	F2017	F2016	11.8	F2019	N/A - In Implementation	11.8	-	-	10.4	-	3.1	6.6	0.2	-	N			Transformers	Page 81	
47	93685	Wood Pole Substation Rep - BTA (Note c)	Sustaining	Definition	F2020	F2019	F2016	-		N/A	-	-	-	-	5.9	-	1.4	3.8	0.1	N			Wood Pole Substation Strategy	Page 64	
48	900726	Joseph Creek (JOE) Substation Upgrade	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	0.2	0.5	6.2	N			Wood Pole Substation Strategy	Page 64	
49	901244	Cathedral Square - Substation HVAC Upgrade	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	-	0.5	N					
50	900724	Woss - Substation Wood Pole Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	0.1	-	-	-	0.1	N			Wood Pole Substation Strategy	Page 64	
51	901045	Canal Flats - Substation Wood Pole Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	-	0.1	Y			Wood Pole Substation Strategy	Page 64	
52	901048	Lumby #2 - Substation Wood Pole Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	0.1	3.2	N			Wood Pole Substation Strategy	Page 64	
53	901049	Skookumchuck - Substation Wood Pole Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	0.0	-	-	-	0.1	N			Wood Pole Substation Strategy	Page 64	
		Stations Risk Mitigation																							
54	92158	Oil Spill Containment - F17/F18 (ALZ / MDN)	Sustaining	Definition	F2021	F2019	F2017	-		8.3 - 6.5	-	-	-	-	7.2	0.4	0.7	2.5	3.6	N			Asset Management Strategy_Section 2.2.8: Oil Spill Containment	Page 63	
55	900766	Project C	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	4.2	-	-	3.1	1.1	Y					
		Telecommunications																							
56	92183	Vancouver Island Radio System	Sustaining	Implementation	F2021	F2018	F2014	32.5	F2021	N/A - In Implementation	32.5	-	-	-	21.5	1.4	7.8	9.6	1.9	N		Page 111	Asset Management Strategy Section 2.4.1 - 2.4.2: Fibre Optic & Microwave Equipment	Page 78	
57	92863	Underrated Telecom Classifications - NTL	Sustaining	Definition	F2020	F2019	F2018	-		3.4 - 6.1	-	-	-	5.3	0.0	0.6	1.4	3.1	0.0	N			Asset Management Strategy Section 2.4.1 - 2.4.2: Fibre Optic & Microwave Equipment	Page 78	
58	92758	CPM MW Repeater Building Rep	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	5.1	0.1	1.6	2.0	1.4	N			Asset Management Strategy Section 2.4.1 - 2.4.2: Fibre Optic & Microwave Equipment	Page 78	
59	900709	Various Sites - Telecom Analog Private Line Replacement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	0.3	2.3	-	-	0.4	2.8	N					
60	93739	Fraser Valley - Telecom System Reliability Upgrade	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	0.5	4.0	N			Asset Management Strategy Section 2.4.1 - 2.4.2: Fibre Optic & Microwave Equipment	Page 78	
61	92768	Various Sites - Telecom MPLS and DACS Upgrade	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	2.1	10.6	N		Page 112	Asset Management Strategy Section 2.4.1 - 2.4.2: Fibre Optic & Microwave Equipment	Page 78	
		Cable Sustainment																							
62	901002	2L146 - Cable Replacement	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	1.0	1.6	N		Page 113	Asset Management Strategy - Section 2.1.10: Transmission Cables	Page 77	
63	94057	Gulf Islands - Transmission Reinforcement	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	-	5.3	N		Page 115	Asset Management Strategy - Section 2.1.10: Transmission Cables	Page 77	
		O/H Lines Life Extension																							
64	91224	Copper Conductor Replace - Phase 2 (Note c)	Sustaining	Implementation	F2019	F2016	F2014	18.2	F2017	N/A - In Implementation	18.2	-	-	10.6	-	3.1	1.2	0.3	-	N			Asset Management Strategy - Section 2.1.2: Conductors	Page 76	
65	92840	Circuit Refurbishments - F15 - 2L13/14	Sustaining	Definition	F2022	F2019	F2015	-		N/A	-	-	-	-	-	0.1	0.4	2.7	9.9	Y			Asset Management Strategy - Section 2.1.11: Transmission Wood Poles	Page 86	
66	94035	5L63 Telkwa Relocation	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	-	0.4	1.4	3.3	12.2	N		Page 116			
67	900889	2L048 - Long Span Crossing Refurbishment	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	0.1	0.2	-	-	0.1	0.2	N			Asset Management Strategy - Section 2.1.2: Conductors	Page 76	
		OH Lines Risk Mitigation																							
68	901242	2L101 - Structure 67/1 Permanent Restoration	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	6.5	-	0.5	6.0	-	N					

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Stage (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F18	Capital Addition Forecast F19	Capital Addition Forecast F20	Capital Addition Forecast F21	Capital Expenditure Actual F18	Capital Expenditure Forecast F19	Capital Expenditure Forecast F20	Capital Expenditure Forecast F21	Extension Project, Y=Yes, N= No	Current or Potential Application (11)	Appendix J Reference	Name for Appendix K Reference (Summaries of Strategies, Plans & Studies)	Appendix K Reference	Program of Projects
		Add: Projects & Programs Less than $5M												164.5	152.5			146.5	139.4						
		TOTAL Gross Sustaining Capital Additions												**217.9**	**234.2**			**244.4**	**315.6**						
		Less: Contributions in Aid of Construction												(5.0)	(8.7)			(5.2)	(5.3)						
		Net Sustaining Capital Additions												**212.9**	**225.5**			**239.2**	**310.3**						
		Transmission Total																							
		Net Growth Capital Additions												**87.7**	**64.8**			**178.7**	**199.5**						
		Net Sustaining Capital Additions												**212.9**	**225.5**			**239.2**	**310.3**						
		Portfolio Delivery Adjustment												**(22.0)**	**(90.0)**			**(34.0)**	**(39.0)**						
		Total												**278.6**	**200.4**			**384.0**	**470.7**						

Note a: Definition work for the project was completed under the Site C Clean Energy Project
Note b: Given the nature of the project, a definition phase was not undertaken.
Note c: ISA is in the fiscal year following the ISD because of a 3 month span between project in-service and finalization of the in-service additions by Finance
Note d: An Appendix J is provided for the Peace Region to Kelly Lake - Reactor Replacement Program of Projects.

Notes:

(1) Information provided is current as of the established 'Currency Date' which is April 1, 2018. Information for certain projects in progress has been updated for significant events subsequent to this date.

(2) Some projects that are in service or forecast to be in service at the end of fiscal 2019 may have trailing expenditures that result in capital additions in the test period. These expenditures and associated capital additions have been aggregated and included in the line item "Projects less than $5 million".

(3) Project / Program dollars are generally capitalized starting either in the feasibility stage of Identification phase or in the Definition phase.

(4) Forecast ISD is the expected in-service date (as at the Currency Date) when the project goes into service.

(5) Start Date of Construction is the Implementation Approval Date. For projects in Definition, the Start of Construction is the forecasted Implementation approval date.

(6) Fiscal Year that the project received Definition phase approval.

(7) Implementation Approval $ refers to the 'Authorized' total capital cost of the project when it was first approved by BC Hydro for Implementation.

(8) Pre-Implementation phases are: Future, Identification and Definition. See Chapter 6, section 6.4.7.4 to 6.4.7.7 for further discussion on pre-Implementation phases. Pre-Implementation cost estimates are provided where an engineering estimate is available. Engineering estimates are generally completed during the mid-stage of Identification phase. N/A indicates that an engineering estimate is not yet available, or that the project is in Implementation phase.

(9) Amounts reflect only the capital portion of the Authorized amount.

(10) Implementation Approval ISD refers to the in-service date identified when the project was first approved by BC Hydro for Implementation.

(11) Project meets the current threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate as of the Currency Date (See Note 1), or in accordance with BCUC Direction No. G-47-18.

Use of To Be Determined (TBD):

For projects in Future or Identification phase, To be Determined (TBD) is provided for the Pre Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start Date of Construction, for the following reasons:
For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In Identification phase, a number of identified alternative responses are being investigated, and each alternative can result in very different project scope, schedule and cost. As a result, Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start of Construction Date are generally only provided for projects in the Definition phase and later phases.

Appendix I - F2020 - F2021 RRA - Distribution
Projects and Programs greater than $5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F20-F21) as at April 1, 2018 (1), (2)
$ Million

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Stage (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F18	Capital Addition Forecast F19	Capital Addition Forecast F20	Capital Addition Forecast F21	Capital Expenditure Actual F18	Capital Expenditure Forecast F19	Capital Expenditure Forecast F20	Capital Expenditure Forecast F21	Extension Project, Y=Yes, N= No	Current or Potential Application (11)	Appendix J Reference	Name for Appendix K Reference (Summaries of Strategies, Plans & Studies)	Appendix K Reference	Program of Projects
Distribution																									
		Growth Capital Expenditures																							
		Customer Driven																							
1	DY-1543	Customer D	Growth	Definition	F2021	F2019	F2018	-		10 - 7	-	-	-	-	6.1	-	0.3	5.8	-	Y					
2	DY-1563	Customer E	Growth	Definition	F2021	F2019	F2018	-		6 - 4	-	-	-	-	5.1	-	0.1	3.3	1.7	Y					
3	DY-0981	Customer F (note a)	Growth	Definition	F2019	F2019	F2018	-		9 - 7	-	0.1	-	8.8	-	0.2	8.7	-	-	Y					
4	901241	Customer G	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	8.0	-	0.2	6.2	1.6	Y					
5	DY-1545	Customer H	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	1.8	3.5	1.8	Y					
		Add: Projects & Programs Less than $5M												217.7	220.1			213.1	228.9						
		Total Customer Driven												**226.5**	**239.3**			**231.9**	**234.0**						
		System Expansion and Improvement																							
6	93639	12F51 & 53 HPN Voltage Conversion (LM-BBY-048) (note a)	Growth	Implementation	F2020	F2018	F2015	12.1	F2020	N/A - In Implementation	12.1	0.2	-	-	8.3	1.3	2.7	3.9	-	Y			Distribution Planning Practice Sections 6.1 6.4.2		
7	93640	HPN 12F54, 72Q, 73Q, and 324 Voltage Conversion (LM-BBY-051)	Growth	Implementation	F2019	F2018	F2016	14.1	F2019	N/A - In Implementation	14.1	0.4	4.4	5.3	-	1.5	3.3	5.3	-	Y			Distribution Planning Practice Sections 6.1 6.4.2		
8	900749	Bringing additional capacity from ARN to Tilbury (FV-FVW-057)	Growth	Implementation	F2020	F2018	F2017	23.7	F2020	N/A - In Implementation	23.7	-	-	18.8	-	4.5	9.5	4.5	-	Y					
9	93669	Three new MLE Feeders to offload CBN (LM-FVE-607)	Growth	Definition	F2021	Jan / F2020	F2015	-		13 - 8	-	0.1	-	-	8.9	0.1	0.1	1.0	7.5	Y					
10	900306	HPN 77Q, 323, 326 and 327 Voltage Conversion Preparation (LM-BBY-062) (note a)	Growth	Definition	F2020	F2019	F2017	-		18 - 10	-	0.8	-	-	11.0	0.8	4.4	4.9	0.6	Y			Distribution Planning Practice Sections 6.1 6.4.2		
11	900307	LOH 12F68 Voltage Conversion and Transfer to HPN (LM-BBY-064) (note a)	Growth	Definition	F2019	F2019	F2016	-		15 - 11	-	0.4	-	5.7	-	0.4	3.5	1.7	-	Y			Distribution Planning Practice Sections 6.1 6.4.2		
12	900342	Voltage Conversion Prep for RIM Substation (LM-FVW-718) (note a)	Growth	Definition	F2020	May / F2020	F2016	-		8 - 6	-	0.1	-	-	7.3	0.7	0.6	2.3	3.6	Y			Distribution Planning Practice Sections 6.1 6.4.2		
13	900386	New MUR Circuit to Offload MUR 12F66 and MUR 12F84 (LM-VAN-020) (note a)	Growth	Definition	F2020	F2019	F2017	-		13 - 7	-	0.5	-	-	7.7	2.5	1.7	3.5	-	Y			Distribution Planning Practice Sections 6.1 6.4.2		
14	900446	WKA New Substation Bring 4 New Feeders (SI-KAM-001)	Growth	Definition	F2020	F2019	F2018	-		18 - 6	-	0.5	-	13.1	-	0.7	10.8	1.7	-	Y			Distribution Planning Practice Sections 6.1 6.4.2		
15	900452	DUG Extension Along Highway 1 East (SI-KAM-008) (note a)	Growth	Definition	F2019	F2019	F2016	-		8 - 5	-	0.1	-	5.5	-	0.2	4.7	0.5	-	Y			Distribution Planning Practice Sections 6.1 6.4.2		
16	94137	CBL New Feeder South Campbell River (VI-NVI-417)	Growth	Identification	TBD	TBD	TBD	-		TBD	-	-	-	6.4	-	-	0.4	6.0	-	Y			Distribution Planning Practice Sections 6.1 6.4.2		
17	901132	Two Fleetwood feeders to offload McLellan (FV-FVW-723)	Growth	Identification	TBD	TBD	TBD	-		TBD	-	-	-	-	13.3	-	0.6	5.7	7.0	Y			Distribution Planning Practice Sections 6.1 6.4.2		
18	901141	Lower Mainland - George Dickie Feeder Voltage Conversion (LM-VAN-066)	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	5.0	-	0.1	2.3	2.6	Y			Distribution Planning Practice Sections 6.1 6.4.2		
19	901253	George Dickie - Voltage Conversion preparation of 4F54, 4F61, 4F64 and 4F65 and cutover to Sperling 12F64 (LM-VAN-094)	Growth	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	0.6	2.9	Y			Distribution Planning Practice Sections 6.1 6.4.2		
		Add: Projects & Programs Less than $5M												25.0	42.8			23.6	25.8						
		Total System Expansion and Improvement												**79.8**	**104.3**			**67.5**	**50.0**						
		Uneconomic Extension Assistance												**0.6**	**0.6**			**0.6**	**0.6**						
		Total Gross Growth Capital												**306.9**	**344.2**			**300.0**	**284.6**						
		Less: Contributions in Aid of Construction												(130.2)	(135.8)			(133.3)	(132.9)						
		Net Growth Capital Additions												**176.7**	**208.4**			**166.7**	**151.7**						
		Sustaining Capital Expenditures																							
		System Expansion and Improvement																							
20	94143	QNL Voltage Conversion (Ni-NC-160)	Sustaining	Implementation	F2020	F2018	F2016	12.8	F2019	N/A - In Implementation	12.8	1.0	-	9.3	-	3.9	3.1	1.1	-	N			Distribution Planning Practice Sections 6.1 6.4.2		
21	900557	H-Frame Elimination - Chinatown (note c)	Sustaining	Implementation	F2020	F2016	note b	48.4	F2019	N/A - In Implementation	48.4	3.3	17.8	13.9	3.7	10.1	10.9	13.9	3.7	N		Page 118			Y
22	900229	Takla Landing (NI-NEW-287)	Sustaining	Definition	F2020	F2019	F2016	-		14 - 8	-	1.3	-	9.1	0.2	3.6	1.5	0.5	0.2	N					
23	900373	New DGR Circuit for Customer Vaults at Pacific and Howe (LM-VAN-004) (note a)	Sustaining	Definition	F2020	F2019	F2016	-		9 - 5	-	0.1	-	-	6.0	0.1	1.4	4.4	-	N			Downtown Vancouver Electric Supply Plan	Page 54	
24	900374	New DGR Circuit for Customer Vaults at Drake and Howe (LM-VAN-005) (note a)	Sustaining	Definition	F2020	F2019	F2016	-		14 - 8	-	0.9	-	-	9.3	0.5	1.8	3.1	3.4	N			Downtown Vancouver Electric Supply Plan	Page 54	
25	900391	Downtown Vancouver - Underground Murrin Feeders to Eliminate H-Frames in Gastown	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	0.5	4.4	13.2	-	0.5	4.4	13.2	N					Y
		Add: Projects & Programs Less than $5M												28.1	43.9			29.2	38.9						
		Total System Expansion and Improvement												**64.8**	**76.3**			**56.6**	**59.4**						
		Asset Replacement																							
26	900556	Various Sites - LED Street Light Conversion	Sustaining	Identification	TBD	TBD	TBD	-		TBD	-	-	-	3.8	5.8	-	-	4.8	6.1	N		Page 120	Asset Management Strategy – Section 3.1.8 – Street Lighting	Page 88	
		Add: Projects & Programs Less than $5M												125.6	113.3			125.0	110.2						
		Total Asset Replacement												**129.4**	**119.1**			**129.8**	**116.3**						
		Beautification												**1.1**	**1.1**			**1.1**	**1.1**						
		Total Gross Sustaining Capital												**195.3**	**196.5**			**187.5**	**176.8**						
		Less: Contributions in Aid of Construction												(0.8)	(0.8)			(0.8)	(0.8)						
		Net Sustaining Capital Additions												**194.5**	**195.7**			**186.8**	**176.0**						
		Distribution Total																							
		Net Growth Capital Additions												**176.7**	**208.4**			**166.7**	**151.7**						
		Net Sustaining Capital Additions												**194.5**	**195.7**			**186.8**	**176.0**						
		Total												**371.2**	**404.1**			**353.5**	**327.7**						

Note a: ISA is in the fiscal year following the ISD because of a 3 month span between project in-service and finalization of the in-service additions by Finance
Note b: This project was approved directly to Implementation and the Definition Phase Activities were completed under the overall Program Management
Note c: An Appendix J is provided for the H-Frame Elimination - Chinatown Program of Projects.

Notes:

(1) Information provided is current as of the established 'Currency Date' which is April 1, 2018. Information for certain projects in progress has been updated for significant events subsequent to this date.

(2) Some projects that are in service or forecast to be in service at the end of fiscal 2019 may have trailing expenditures that result in capital additions in the test period. These expenditures and associated capital additions have been aggregated and included in the line item "Projects less than $5 million".

(3) Project / Program dollars are generally capitalized starting either in the feasibility stage of Identification phase or in the Definition phase.

(4) Forecast ISD is the expected in-service date (as at the Currency Date) when the project goes into service.

(5) Start Date of Construction is the Implementation Approval Date. For projects in Definition, the Start of Construction is the forecasted Implementation approval date.

(6) Fiscal Year that the project received Definition phase approval.

(7) Implementation Approval $ refers to the 'Authorized' total capital cost of the project when it was first approved by BC Hydro for Implementation.

(8) Pre-Implementation phases are: Future, Identification and Definition. See Chapter 6, section 6.4.7.4 to 6.4.7.7 for further discussion on pre-Implementation phases. Pre-Implementation cost estimates are provided where an engineering estimate is available. Engineering estimates are generally completed during the mid-stage of Identification phase. N/A indicates that an engineering estimate is not yet available, or that the project is in Implementation phase.

(9) Amounts reflect only the capital portion of the Authorized amount.

(10) Implementation Approval ISD refers to the in-service date identified when the project was first approved by BC Hydro for Implementation.

(11) Project meets the current threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate as of the Currency Date (See Note 1), or in accordance with BCUC Direction No. G-47-18.

Use of To Be Determined (TBD):

For projects in Future or Identification phase, To be Determined (TBD) is provided for the Pre Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start Date of Construction, for the following reasons:
For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In Identification phase, a number of identified alternative responses are being investigated, and each alternative can result in very different project scope, schedule and cost. As a result, Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start of Construction Date are generally only provided for projects in the Definition phase and later phases.

Appendix I - F2020-F2021 RRA - Technology
Projects and Programs greater than $2 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F20-F21) as at July 1, 2018 (1), (2)

$ million

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Stage (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F18	Capital Addition Forecast F19	Capital Addition Forecast F20	Capital Addition Forecast F21	Capital Expenditure Actual F18	Capital Expenditure Forecast F19	Capital Expenditure Forecast F20	Capital Expenditure Forecast F21	Extension Project, Y=Yes, N= No	Current or Potential Application, Y=Yes, N= No (11)	Appendix J Reference	Technology Strategy & 5 Year Plan (Appendix L) Business Outcome References	Appendix K Reference	Program of Projects or Related Planning IDs
		Manage Compliance and Security																							
		Projects Over $2 million																							
1	T001549	End of Life Firewall Replacement	Sustaining	Definition	F2020	TBD	F2018	TBD	TBD	3.3 - 1.9	-	-	-	3.6	-	0.3	1.3	2.0	-	N	N	N/A	Resilient and secure IT and OT systems;	N/A	N/A
2	T001390	Data Centre Network Security Improvement	Sustaining	Definition	F2021	TBD	F2018	TBD	TBD	3.7 - 2.1	-	-	-	2.5	-	0.0	0.5	2.0	-	N	N	N/A	Resilient and secure IT and OT systems;	N/A	N/A
3	T002055	NERC Critical Infrastructure Protection (CIP) v7	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	N/A	-	-	-	2.3	-	-	-	2.3	-	N	N	N/A	Resilient and secure IT and OT systems; Physical grid security	N/A	Related projects
		Programs over $2 million																							
4	T001913	Microsoft Enterprise Agreement True Up F20-F21	Sustaining	Future	TBD	TBD	N/A	N/A	N/A	N/A	-	-	-	2.0	2.0	-	-	2.0	2.0	N	N	N/A	Improved employee experience, productivity and collaboration	N/A	Recurring
5	T001909	Infrastructure Software F20-F21	Sustaining	Future	TBD	TBD	N/A	N/A	N/A	N/A	-	-	-	1.7	1.8	-	-	1.7	1.8	N	N	N/A	Improved employee experience, productivity and collaboration	N/A	Recurring
		Projects and Programs less than $2 million	Sustaining									-		7.7	3.8			5.0	4.3	N	N	N/A	(Various)		
		Subtotal (Compliance and Security)												19.7	7.6			14.8	8.1						
		Manage Risk and Sustain Productivity																							
		Projects over $2 million																							
6	T001577	HydroShare HydroWeb Upgrade	Sustaining	Definition	F2020	TBD	F2018	TBD	TBD	6.8 - 3.9	-	-	-	7.3	-	0.3	3.8	3.3	-	N	N	N/A	Resilient and secure IT and OT systems;	N/A	T001577, T001719
7	T001397	Contact Centre Technology Foundation Refresh	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	TBD	-	-	-	-	6.4	-	-	3.2	3.2	N	N	N/A	Resilient and secure IT and OT systems;	N/A	N/A
8	T001070	CIDC Network Refresh	Sustaining	Identification	TBD	TBD	TBD	TBD	TBD	TBD	-	-	-	-	6.0	-	1.5	4.5	-	N	N	N/A	Resilient and secure IT and OT systems;	N/A	N/A
9	T001379	SAP HANA-ECC Upgrade	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	TBD	-	-	-	-	6.0	-	-	-	6.0	N	N	N/A	Resilient and secure IT and OT systems;	N/A	
10	T001105	Next Generation Desktop (Windows 10)	Sustaining	Definition	F2021	TBD	F2018	TBD	TBD	11.1 - 6.3	-	-	-	4.8	0.9	-	1.9	2.8	0.9	N	N	N/A	Resilient and secure IT and OT systems;	N/A	N/A
11	T001877	GE Smallworld GIS 5.x Upgrade	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	TBD	-	-	-	-	4.3	-	-	0.8	3.5	N	N	N/A	Resilient and secure IT and OT systems;	N/A	N/A
12	T002082	Meter Data Management System (MDMS) v9 Upgrade	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	TBD	-	-	-	3.8	-	-	0.8	3.0	-	N	N	N/A	Resilient and secure IT and OT systems;	N/A	N/A
13	T001723	Customer Connect Web Enablement	Sustaining	Identification	F2020	TBD	TBD	TBD	TBD	TBD	-	-	-	2.8	-	-	0.8	2.0	-	N	N	N/A	Resilient and secure IT and OT systems;	N/A	N/A
14	T002083	MDMS Improvements	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	TBD	-	-	-	0.8	1.5	-	-	0.8	1.5	N	N	N/A	Enhanced data access and business intelligence;	N/A	N/A
15	T001402	LodeStar and Enhanced Billing System (Transmission)	Sustaining	Identification	F2020	TBD	TBD	TBD	TBD	TBD	-	-	-	2.2	-	0.3	1.2	0.6	-	N	N	N/A	Resilient and secure IT and OT systems;	N/A	N/A
16	T001719	SharePoint Workspaces Upgrade	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	TBD	-	-	-	-	-	-	-	0.0	2.5	N	N	N/A	Resilient and secure IT and OT systems;	N/A	T001577, T001719
		Programs over $2 million																							
17	T001910	Server Sustainment (Capacity) F20-F21	Sustaining	Future	TBD	TBD	N/A	N/A	N/A	N/A	-	-	-	4.0	4.5	-	-	4.0	4.5	N	N	N/A	Resilient and secure IT and OT systems;	N/A	Recurring
18	T001663	PC Client Refresh F19	Sustaining	Future	TBD	TBD	N/A	N/A	N/A	N/A	-	-	3.8	0.3	-	-	3.8	0.3	-	N	N	N/A	Resilient and secure IT and OT systems;	N/A	Recurring
19	T001911	PC Client Refresh F20-F21	Sustaining	Future	TBD	TBD	N/A	N/A	N/A	N/A	-	-	-	4.5	4.2	-	-	4.5	4.2	N	N	N/A	Resilient and secure IT and OT systems;	N/A	Recurring
20	T001912	Operations PC Inventory F20-F21	Sustaining	Future	TBD	TBD	N/A	N/A	N/A	N/A	-	-	-	1.8	1.8	-	-	1.8	1.8	N	N	N/A	Resilient and secure IT and OT systems;	N/A	Recurring
21	T001667	Storage Capacity Growth F20-F21	Sustaining	Future	TBD	TBD	N/A	N/A	N/A	N/A	-	-	-	3.0	3.5	-	-	3.0	3.5	N	N	N/A	Resilient and secure IT and OT systems;	N/A	Recurring
22	T001915	Provisioning of Mobile Devices F20-F21	Sustaining	Future	TBD	TBD	N/A	N/A	N/A	N/A	-	-	-	1.8	1.8	-	-	1.8	1.8	N	N	N/A	Resilient and secure IT and OT systems; Safety practices integrated into work process on site	N/A	Recurring
23	T002067	Mobile Vehicle Wifi Refresh F20	Sustaining	Future	TBD	TBD	N/A	N/A	N/A	N/A	-	-	-	1.5	-	-	-	1.5	-	N	N	N/A	Resilient and secure IT and OT systems; Safety practices integrated into work process on site	N/A	Recurring
24	T002068	Mobile Vehicle Wifi Refresh F21	Sustaining	Future	TBD	TBD	N/A	N/A	N/A	N/A	-	-	-	-	1.8	-	-	-	1.8	N	N	N/A	Resilient and secure IT and OT systems; Safety practices integrated into work process on site	N/A	Recurring
		Projects and Programs less than $2 million	Sustaining									-	-	34.1	22.9			30.9	17.9	N	N	N/A	(Various)		
		Subtotal (Risk and Productivity)												72.6	65.7			68.8	53.1						
		Enhance Business Capability																							
		Projects Over $2 million																							
25	T001127	Supply Chain Applications (1)	Sustaining	Definition	F2020	TBD	F2016	TBD	TBD	71.8 - 59.2	-	-	-	57.4	-	11.0	23.9	19.0	0.0	N	Y	Page 121	Optimized supply chain function	N/A	N/A
26	T001851	Stations Work Planning, Scheduling and Work Execution	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	TBD	-	-	-	-	6.4	-	0.4	3.5	2.5	N	N	N/A	Operations work planning and scheduling	N/A	N/A
27	T001637	Asset Investment Planning Tool	Sustaining	Future	TBD	TBD	TBD	TBD	TBD	TBD	-	-	-	-	-	-	0.6	4.2	1.0	N	N	N/A	Integrated and optimized investment planning	N/A	N/A
28	T001611	Autodesk Substation Design Suite	Sustaining	Definition	F2020	TBD	F2018	TBD	TBD	3.8 - 2.1	-	-	-	2.4	-	0.2	1.3	0.9	-	N	N	N/A	Enhanced engineering design	N/A	N/A
29	T001035	Dam Safety Information System (DSIS)	Sustaining	Identification	F2121	TBD	TBD	TBD	TBD	TBD	-	-	-	-	2.2	-	0.4	1.0	0.9	N	N	N/A	Enhanced dam safety systems	N/A	N/A
30	T000625	Fleet Telematics	Sustaining	Identification	F2021	TBD	TBD	TBD	TBD	TBD	-	-	-	-	2.2	-	0.3	1.8	0.1	N	N	N/A	Integrated and optimized investment planning	N/A	N/A
		Programs over $2 million																							
		Projects and Programs less than $2 million	Sustaining									-	-	13.5	1.5			4.0	0.4	N	N	N/A	(Various)		
		Subtotal (Business Capability)												73.3	12.3			34.4	4.8						
31		Portfolio Adjustment												(24.6)	(10.5)			(24.6)	(10.5)						
		Total												141.0	75.0			93.5	55.5						

Notes:

(1) Information provided is current as of the established 'Currency Date' which is July 1, 2018**. On October 12, 2018, a** Phase Two Application relating to the Supply Chain Applications project was filed with the Utilities Commission. As shown in Appendix J, the information as of September 27, 2018 was an Implementation phase project with Forecast Capital Cost of $68.0M. Refer to Appendix J for further information at this later date.

(2) Some projects that are in service or forecast to be in service at the end of F2019 may have trailing expenditures that result in capital additions in the test period. These expenditures and associated capital additions have been aggregated and included in the line item "Projects and Programs under $2 million".

(3) Project/ Program dollars are generally capitalized starting in the Definition phase.

(4) Forecast ISD is the expected in-service date (as at the Currency Date) when the project goes into service.

(5) Start Date of Construction is the Implementation Approval Date.

(6) Fiscal Year that the project received Definition phase approval.

(7) Implementation Approval $ refers to the 'Authorized' total capital cost of the project when it was first approved by BC Hydro for implementation. "N/A" is used for recurring programs.

(8) Pre-Implementation phases are: Future, Identification and Definition. See Chapter 6, section 6.XXX, for further discussion on pre-Implementation phases. Pre-implementation cost estimates are provided in Definition phase. N/A indicates that an engineering estimate is not yet available, or that project is in implementation phase.

(9) Amounts reflect only the capital portion of the Authorized amount.

(10) Implementation Approval ISD refers to the in-service date date identified when the project was first approved by BC Hydro for implementation. "N/A" is used for recurring programs.

(11) Project meets the threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate as of the Currency Date (See Note

Use of To Be Determined (TBD):

For projects in Future or Identification Phase, To Be Determined (TBD) is provided for the following: Current Pre-Implementation Cost Estimate, Current Forecast In-service Date (ISD) and Current Start Date of Construction, for the following reasons:

For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In the Identification Phase, a number of identified alternative responses are being investigated, and each alternative can result in a very different project scope, schedule and cost. As a result, Current Pre-Implementation Cost Estimate, Current Forecast In-Service Date (ISD) and Current Start Date of Construction, are only provided for projects in the Definition phase and later phases.

Appendix I - F2020 - F2021 RRA - Other
Projects and Programs greater than $5 million with Capital Expenditures in the Test Period and/or Capital Additions in the Test Period (F20-F21) as at April 1, 2018 (1), (2)

$ Million

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
	Planning ID	Name of Project	Growth or Sustaining Expenditure	Development Stage (3)	Forecast ISD (4)	Start Date of Construction (5)	Definition Approval Date (6)	Implementation Approval $ (7)	Implementation Approval ISD (10)	Pre-Implementation Cost Estimate (8)	Authorized Amount (9)	Capital Addition Actual F18	Capital Addition Forecast F19	Capital Addition Forecast F20	Capital Addition Forecast F21	Capital Expenditure Actual F18	Capital Expenditure Forecast F19	Capital Expenditure Forecast F20	Capital Expenditure Forecast F21	Extension Project, Y=Yes, N= No	Current or Potential Application (11)	Appendix J Reference	Name for Appendix K Reference (Summaries of Strategies, Plans & Studies)	Appendix K Reference	Program of Projects
Properties																									
1	P201701	Pemberton Field Building Redevelopment	Sustaining	Implementation	F2020	F2018	F2017	11.0	F2020	N/A	11.0	-	-	11.0	-	0.6	5.3	4.8	0.0	N	N		N/A	N/A	N
2	P201601	Long Beach Field Building Redevelopment	Sustaining	Definition	F2020	F2019	F2016	-		N/A	-	-	-	7.9	-	0.4	1.3	5.8	0.0	N	N		N/A	N/A	N
3	P201702	Materials Management Building Redevelopment	Sustaining	Definition	F2021	F2019	F2017	-		N/A	-	-	-	-	11.9	0.7	3.6	6.2	1.1	N	N		N/A	N/A	N
4	P201703	Chilliwack Field Building Redevelopment	Sustaining	Definition	F2021	F2019	F2017	-		N/A	-	-	3.8	-	28.2	1.0	5.3	12.4	12.3	N	N	Page 123	N/A	N/A	N
5	P201704	Materials Classification Facility Building Redevelopment	Sustaining	Definition	F2022	F2019	F2017	-		N/A	-	-	-	-	-	0.6	3.1	7.1	23.3	N	N	Page 125	N/A	N/A	N
6	P201901	Kamloops Field Building Redevelopment	Sustaining	Future	TBD	TBD	TBD			TBD	-	-	-	-	-	-	-	1.5	3.0	N	N	Page 127	N/A	N/A	N
7		Projects Less Than $5 Million	Sustaining	Multiple	Multiple	Multiple	Multiple	Multiple	Multiple	Multiple	Multiple			21.1	15.6			21.1	15.6	N	N		N/A	N/A	N
		Total										-	-	39.9	55.6			58.9	55.3						
Other Capital																									
		Other Technology																							
8	900864	Mobile Radio Optimization - LM	Sustaining	Implementation	F2020	F2016	F2016	9.5	F2019	N/A	9.5	-	-	6.6	0.5	0.8	2.4	2.1	0.5	N	N		N/A	N/A	N
9		Fleet/Vehicles	Sustaining	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	29.8	30.2	26.2	27.8	31.0	30.2	26.2	27.8	N	N		N/A	N/A	Y
		Business Support - Other																							
10	901006	Itron OpenWay Systems and Cisco Field Network Director Upgrade	Sustaining	Definition	F2018	F2019	F2017	-		N/A	-	-	6.2	4.7	0.8	1.1	7.5	4.0	0.0	N	N			N/A	N
11	93632	Project B (Property)	Growth	Identification	TBD	TBD	TBD	-		TBD	-	-	-	[redacted]	[redacted]	-	[redacted]	[redacted]	[redacted]	Y	N	Page 93	[redacted]	Page 72	
12	FC-00420	Materials Management - Oil Management Operating Infrastructure	Sustaining	Future	TBD	TBD	TBD	-		TBD	-		-	5.1	8.5	-	1.0	5.1	7.6	N	N		N/A	N/A	N
13	YM-00153	Learning & Development - Energized Training Substation	Sustaining	Future	TBD	TBD	TBD	-		TBD	-	-	-	-	-	-	-	-	5.8	N	N		N/A	N/A	N
14		Projects Less Than $5 Million	Sustaining	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	-	27.2	23.8			26.9	23.5	N	N		N/A	N/A	N
		Total												38.7	43.5			37.4	47.3						
		Total Fleet/Other												64.9	71.3			63.6	75.1						
Site C Project																									
15	1115778		Growth	Implementation	F2024 (Unit 1)	F2016	F2015	7,575.20	F2024 (Unit 1)	N/A	10,005.0	-	-	27.9	189.4	704.8	1,186.8	1530.0	1535.5	Y	Exempt per Clean Energy Act, sec. 7(1)	Page 129	N/A		N

Notes:

(1) Information provided is current as of the established 'Currency Date' which is April 1, 2018. Information for projects in progress has been updated for significant events subsequent to these dates.
(2) Some projects that are in service or forecast to be in service at the end of fiscal 2019 may have trailing expenditures that result in capital additions in the test period. These expenditures and associated capital additions have been aggregated and included in the line item "Projects less than $5 million".
(3) Project / Program dollars are generally capitalized starting either in the feasibility stage of Identification phase or in the Definition phase.
(4) Forecast ISD is the expected in-service date (as at the Currency Date) when the project goes into service.
(5) Start Date of Construction is the Implementation Approval Date. For projects in Definition, the Start of Construction is the forecasted Implementation approval date.
(6) Fiscal Year that the project received Definition phase approval.
(7) Implementation Approval $ refers to the 'Authorized' total capital cost of the project when it was first approved by BC Hydro for Implementation.
(8) Pre-Implementation phases are: Future, Identification and Definition. See Chapter 6, section 6.4.7.4 to 6.4.7.7 for further discussion on pre-Implementation phases. Pre-Implementation cost estimates are provided where an engineering estimate is available. Engineering estimates are generally completed during the mid-stage of Identification phase. N/A indicates that an engineering estimate is not yet available, or that the project is in
(9) Amounts reflect only the capital portion of the Authorized amount.
(10) Implementation Approval ISD refers to the in-service date identified when the project was first approved by BC Hydro for Implementation.
(11) Project meets the current threshold for a CPCN or Section 44.2 Application based on the Project Authorized Cost Amount, or may meet the threshold, based on the planning cost allowance or cost estimate as of the Currency Date (See Note 1), or in accordance with BCUC Direction No. G-47-18.

Use of To Be Determined (TBD):
For projects in Future or Identification phase, To be Determined (TBD) is provided for the Pre Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start Date of Construction, for the following reasons:
For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined. In Identification phase, a number of identified alternative responses are being investigated, and each alternative can result in very different project scope, schedule and cost. As a result, Pre-Implementation Cost Estimate, Forecast In-Service Date (ISD) and Start of Construction Date are generally only provided for projects in the Definition phase and later phases.

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix J

Capital Expenditures > $20 million

Appendix J Summaries

Appendix J, Attachment 1 provides descriptions for capital projects and programs of projects with planned capital expenditures or additions in the test period, with planned total capital expenditures greater than $20 million. Consistent with section 9 of Exhibit B-7 (Compliance with Commission Order No. G-59-18 - Revised Proposal) (**Revised Proposal)**, BC Hydro has included the following additional information in Appendix J:

- A summary of the project's impacts and benefits;
- For projects in the Implementation Phase, the construction start date; and
- A summary of risk(s) and risk treatment for projects in the Implementation Phase.[1]

Consistent our Previous Application, the Appendix J project summaries include information on the key drivers of the capital projects. In this application these key drivers are aligned with the consequence types identified in BC Hydro's Corporate Risk Matrix.

The Corporate Risk Matrix identifies the following "consequence types" or risk impacts:

- Safety – This includes the safety of both the public and BC Hydro workers;
- Environmental – This includes impacts to habitats and species;

[1] Summaries of Implementation Phase risks are provided for those projects in Implementation Phase, with identified high severity and/or high probability consequences, or a combination of moderate severity and probability consequences. The assessment is based on BC Hydro's Project Delivery Risk Matrix which classifies project Implementation risks into three zones, from low (zone 1) to high (zone 3). The Project Delivery Risk Matrix is derived from the Corporate Risk Matrix. As discussed in Chapter 6, sections 6.4.7.7 to 6.4.7.9, project risks are identified starting in the Identification Phase and are finalized in the Implementation Phase.

- Financial Loss (Financial) – This includes direct financial loss or costs;
- Reputational – This includes responses from the public, media and public officials as well as impacts to projects, programs, plans and operations as a result of these responses; and
- Reliability – This includes customer reliability (hours lost per event) and reliability of supply.

The Appendix J capital project summaries identify which of these five categories of consequence types are the key drivers for investments that are risk driven.

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix J

Attachment 1

Descriptions of Capital Projects and Programs of Projects

PUBLIC

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Generation			
Hydroelectric			
Growth			
Revelstoke Install Unit 6	1	Page 1	Page 35
Redevelopment / Rehabilitation			
John Hart Generating Station Replacement	2	Page 3	Page 17
Dam Safety			
W.A.C. Bennett Dam Rip‑Rap Upgrade	4	Page 5	Page 13
Alouette Improve Headworks & Surge Tower Seismic Stability	5	Page 7	Page 3
Bridge River 1 - Mitigate Surge Spill Hazard	6	N/A	Page 7
Bridge River 1 Improve Slope Drainage	7	N/A	Page 7
Comox - Puntledge Flow Control Improvements	8	Page 9	Page 33
Duncan Dam Replace Spillway Gates	9	Page 11	Page 12
John Hart Dam Seismic Upgrade	10	Page 13	Page 1
Ladore Spillway Seismic Upgrade	11	Page 15	Page 1
Peace Canyon Install Piezometers and Drains in Concrete Dam	12	N/A	Page 29
Revelstoke Improve Left Bank Slope Stability	13	N/A	Page 35
Revelstoke Replace Downie Slide Instrumentation	14	N/A	Page 35
Strathcona Upgrade Discharge	15	Page 17	Page 1
W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates	16	Page 19	Page 13
W.A.C. Bennett Dam Seal Low Level Outlets	17	Page 21	Page 13
Alouette - Environmental Flow Discharge Upgrade and LLO Sealing	18	N/A	Page 3
Hugh Keenleyside - Spillway and Low Level Outlets Concrete Upgrade	19	Page 23	Page 15
Mica - Discharge Facilities Seismic and Reliability Upgrades	20	Page 25	Page 26
Terzaghi - Spillway Chute Access Improvement	21	N/A	Page 7
Sustaining - Other			
Bridge River 2 Upgrade Units 5 and 6	23	Page 27	Page 7

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Cheakamus Replace Units 1 and 2 Turbine Inlet Valves	24	N/A	Page 10
Cheakamus Units 1 and 2 Generator Replacement	25	Page 30	Page 10
G.M. Shrum G1 to Control System Upgrade	26	Page 32	Page 13
G.M. Shrum Replace Unit 1-5 Exciter Transformers	27	N/A	Page 13
Kootenay Canal Upgrade Unit Protection and Install Sequence of Events Recorder	28	N/A	Page 20
Mica Replace Fire Alarm System	29	N/A	Page 26
Mica Replace Units 1 to 4 Generator Transformers	30	Page 34	Page 26
Mica Townsite Augment Accommodations Capacity	31	Page 36	Page 28
Mica Upgrade Powerhouse Cranes	32	Page 37	Page 26
Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)	33	Page 38	Pages 10 and 31
G.M. Shrum Replace / Refurbish 500KV Disconnect Switches	34	N/A	Page 13
G.M. Shrum Upgrade HVAC System	35	Page 40	Page 13
Hugh Keenleyside Replace Service Water Piping	36	N/A	Page 15
Kootenay Canal Upgrade Powerhouse Crane	37	N/A	Page 20
Lake Buntzen 1 - Power House Crane Upgrade	38	N/A	Page 24
Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment	39	Page 41	Page 24
Mica Modernize Controls	40	Page 43	Page 26
Mica Upgrade 600V Circuit Breakers	41	N/A	Page 26
Mica Upgrade HVAC System	42	N/A	Page 26
Peace Canyon Upgrade HVAC System	43	N/A	Page 29
Puntledge Recoat Interior and Exterior of Steel Penstock	44	Page 44	Page 31 and 33
Revelstoke - 600V Circuit Breaker Upgrades	45	N/A	Page 35
Seven Mile Replace Unit 1-4 Exciter Transformers	46	N/A	Page 39
Wahleach Recoat Penstock (Interior and Exterior)	48	Page 46	Page 31 and 44
Wahleach Refurbish Generator	49	Page 48	Page 44
Ash River Extend Life of Steel Penstock	50	N/A	Pages 5 and 31

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
Bridge River 1 - Strip and Recoat Penstocks 1-4 Interior	51	Page 49	Pages 7 and 31
Bridge River 1 Replace Units 1-4 Generators / Governors	52	Page 50	Page 7
Bridge River 2 - Strip and Recoat Penstock 2 Interior	53	N/A	Pages 7 and 31
Bridge River 2 Upgrade Units 7 and 8	54	Page 52	Pages 7 and 31
Hugh Keenleyside Recoat Navlock Gates	55	N/A	Page 15
Jordan - Upgrade Governor & PRV Controls	56	N/A	Page 18
Kootenay Canal Modernize Controls	57	Page 54	Page 20
Ladore - Redevelop Unit 1	58	Page 56	Page 22
Ladore Upgrade Protection and Control Systems	59	N/A	Page 22
Lake Buntzen 1 Penstock Exterior Recoat	60	N/A	Page s 24 and 31
Mica - Recoat Intake Maintenance Gates & Draft Tube Maintenance Gates	61	N/A	Page 26
Peace Canyon - 600V Circuit Breaker Upgrades	62	N/A	Page 29
Revelstoke Replace Fire Alarm System	63	N/A	Page 35
Seton - Upgrade Unit	64	Page 57	Page 37
Seven Mile - Replace T1 Transformer	65	N/A	Page 39
Seven Mile Overhaul Units 1 to 3 Turbines	66	Page 59	Page 39
Seven Mile Upgrade Powerhouse Crane Controls	67	N/A	Page 39
Stave Falls - Improve Unit 1&2 Turbine Pitch Assemblies	68	N/A	Page 39
Waneta U3 Life Extension	71	Page 61	N/A
G.M. Shrum - Intake Operating Gate and Intake Maintenance Gate Refurbishment	72	N/A	Page 13
G.M. Shrum - Intake Operating Gate Hydraulic Upgrade	73	Page 63	Page 13
G.M. Shrum - Pauwels Transformer Life Extension	74	N/A	Page 13
G.M. Shrum - Transformers Phase 4 Replacement	75	N/A	Page 13
G.M. Shrum - U1 - U10 Water Passage Refurbishment	76	Page 64	Page 13
G.M. Shrum - U9 - U10 Circuit Breaker Replacement	77	N/A	Page 13

Cross Reference Index for Appendices I, J and K			
	Reference		
Project Name	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Lake Buntzen 1 - Generator Replacement	78	Page 65	Page 24
Mica - Intake Gantry Crane Refurbishment	79	N/A	Page 26
Peace Canyon - High and Low Pressure Piping Replacement	80	N/A	Page 29
Peace Canyon - U1 - U4 Exciter Replacement	81	N/A	Page 29
Revelstoke - U1 - U4 Stator Replacement	82	Page 66	Page 35
Seven Mile - U1 - U4 Controls Upgrade	83	N/A	Page 39
Strathcona - G1 Generator Rewind	84	N/A	Page 42
Transmission			
Growth Capital Expenditures			
Regional System Reinforcement			
Fort St. John and Taylor Electric Supply	1	Page 67	N/A
DVES: West End Strategic Property Purchase	2	Page 69	Page 54
Peace Region Electric Supply (PRES)	3	Page 71	Page 75
Metro North Transmission (MNT)	4	Page 73	Page 60
Bridge River Transmission Project	5	Page 75	Page 50
West Kelowna Transmission and Westbank Upgrade Projects	6	Page 77	Page 83
East Vancouver - Substation Construction	7	Page 79	Page 54
West End - Substation Construction and System Reinforcement	8	Page 80	Page 54
Bulk System Reinforcements			
Peace to Kelly Lake Capacitors	9	Page 82	Page 66
Lower Mainland - Capacitive and Reactive Power Reinforcement	10	Page 84	Page 58
Interior to Lower Mainland - Remedial Action Schemes Installation	11	Page 86	N/A
Station Expansion & Modification			
Capilano Substation Upgrade	12	Page 87	Pages 51 and 69
Mount Lehman Substation Upgrade	13	Page 89	Pages 46 and 51
Clayburn Substation Upgrade	14	Page 91	Pages 46 and 51
Project B (Substation)	15	Page 93	Page 72

Cross Reference Index for Appendices I, J and K			
Project Name	**Reference**		
	Appendix I (Line Number)	**Appendix J (Page Number)**	**Appendix K (Page Number)**
Pemberton - Substation Upgrade	16	Page 95	N/A
Sustaining Capital Expenditures			
Circuit Breakers			
Copper Conductor Replace - Phase 2	22	N/A	Pages 48 and 51
SPG Metalclad Switchgear Replacement	23	Page 97	Pages 51 and 71
Other Power Equipment			
500kV Capacitor Bank P&C Upgrades	24	N/A	Page 79
Barnard 50/60 Feeder Section Replacement	25	Page 98	Page 48
SC Excitation Systems Upgrade - VIT/KLY	26	N/A	Page 74
Synch Condensor Functional Imp - F17/F18	27	N/A	Page 74
VIT & KLY Hydrogen Gas Sys - Safety Upg	28	N/A	Page 74
BR1 T3 & BRT T4A Replacement	29	Page 99	Page 81
Hundred Mile House T1/T2 EOL Replacement	30	N/A	Page 81
JOR T1 & T2 Replacement	31	Page 101	Page 81
KI1 60Kv Renovatin, 4Kv decommission & control room	32	N/A	Pages 51 and 56
Mainwaring Station Upgrade	33	Page 103	Pages 51 and 59
Natal Sub - NTL 60-138 kV Rebuild	34	Page 105	Page s 51 and 62
Newell Substation Upgrade	35	N/A	Pages 51 and 61
Peace Region to Kelly Lake - Reactor Replacement (Phase 1)	36	Page 107	Page 67
Ah-sin-heek - Substation Replacement	37	N/A	Page 84
Norgate - Substation Upgrade	38	Page 108	Pages 51 and 69
Patricia - Substation Upgrade	39	N/A	Pages 51 and 65
Peace Region to Kelly Lake - Reactor Replacement (Phase 2)	40	Page 107	Page 67
Protection and Control			
NERC CIP V5 Compliance at Medium Impact T&D Stations	41	Page 109	Page 79

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
Control PLC984 and RTU Replacement (WSN)	42	N/A	Page 79
Control Systems Upgrade (GMS)	43	N/A	Page 79
Stations Auxiliary Equipment			
Wood Pole Substation Rep - MTE	44	N/A	Page 64
Wood Pole Substation Rep - PSN	45	N/A	Page 64
Stn Service Transfer & AC panels - WSN	46	N/A	Page 81
Wood Pole Substation Rep - BTA	47	N/A	Page 64
Joseph Creek (JOE) Substation Upgrade	48	N/A	Page 64
Woss - Substation Wood Pole Replacement	50	N/A	Page 64
Canal Flats - Substation Wood Pole Replacement	51	N/A	Page 64
Lumby #2 - Substation Wood Pole Replacement	52	N/A	Page 64
Skookumchuck - Substation Wood Pole Replacement	53	N/A	Page 64
Stations Risk Mitigation			
Oil Spill Containment - F17/F18 (ALZ / MDN)	54	N/A	Page 53
Telecommunications			
Vancouver Island Radio System	56	Page 111	Page 78
Underrated Telecom Classifications - NTL	57	N/A	Page 78
CPM MW Repeater Building Rep	58	N/A	Page 78
Fraser Valley - Telecom System Reliability Upgrade	60	N/A	Page 78
Various Sites - Telecom MPLS and DACS Upgrade	61	Page 112	Page 78
Cable Sustainment			
2L146 - Cable Replacement	62	Page 113	Page 77
Gulf Islands - Transmission Reinforcement	63	Page 115	Page 77
O/H Lines Life Extension			
Copper Conductor Replace - Phase 2	64	N/A	Page 76
Circuit Refurbishments - F15 - 2L13/14	65	N/A	Page 86
5L63 Telkwa Relocation	66	Page 118	N/A
2L048 - Long Span Crossing Refurbishment	67	N/A	Page 76
Distribution			
Sustaining Capital Expenditures			
System Expansion and Improvement			
H-Frame Elimination - Chinatown	21	Page 118	N/A

Cross Reference Index for Appendices I, J and K			
Project Name	Reference		
	Appendix I (Line Number)	Appendix J (Page Number)	Appendix K (Page Number)
New DGR Circuit for Customer Vaults at Pacific and Howe (LM-VAN-004)	23	N/A	54
New DGR Circuit for Customer Vaults at Drake and Howe (LM-VAN-005)	24	N/A	54
Various Sites - LED Street Light Conversion	26	Page 120	Page 88
Technology			
Enhance Business Capability			
Projects Over $2 million			
Supply Chain Applications	25	Page 121	N/A
Other			
Properties			
Chilliwack Field Building Redevelopment	4	Page 123	N/A
Materials Classification Facility Building Redevelopment	5	Page 125	N/A
Kamloops Field Building Redevelopment	6	Page 127	N/A
Other Capital			
Project B (Property)	11	Page 93	Page 72

<table>
<tr><td colspan="1">Investment Planning ID:
G000594</td><td colspan="2">Project Name:
Revelstoke Install Unit 6</td></tr>
<tr><td>Forecast Capital Cost:
$569 million to $317 million</td><td>Forecast In-Service:
Fiscal 2030</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Definition</td><td colspan="2">Filing Reference:
2008 LTAP:
• Appendix F1 Resource Options Database (RODAT) Sheets
F11 RRA:
• BCUC IRs 1.5.1, 1.5.1.1 – 1.5.1.3, 1.217.1 Attachment 6, 1.285.6, 1.331.1 Attachments 1 and 2, 2.515.1, 2.545.5 Attachment 1, 2.599.3, 3.669.1;
• IPPBC IR 1.1.6 Attachment 4
Amended F12-F14 RRA
• Amended Appendix I, line 136; Amended Appendix J, page 72
F17-F19 RRA:
• Appendix I, line 1, Appendix J, page 1,
• BCUC IRs 1.70.3, 1.81.1 – 1.81.14, 2.249.8, 2.260.4, BCOAPO IR 1.36.1</td></tr>
<tr><td colspan="3">Description:
The purpose of the Revelstoke Unit 6 project is to install a 500 MW unit in the existing empty Unit 6 bay at the Revelstoke Generating Facility. The scope of the Revelstoke Unit 6 installation project would involve the installation of a sixth penstock, turbine, generator, and all ancillary equipment required in the generating station. In addition, there is a transmission requirement for an additional series capacitor station on the transmission line from Vaseux to Nicola and some enhancements within existing substations.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
There is one remaining empty bay where a sixth unit could be installed to meet the requirement for additional capacity in the BC Hydro system. Revelstoke Unit 6 is the least cost alternative for adding this additional capacity.
Based on the Reference Price Update (December 2018), REV6 is the least cost alternative ($58/kw-yr) for adding additional capacity to the BC Hydro system and, as such, is the next capacity resource option for the BC Hydro system. The load resource balance is in a deficit in fiscal 2023; by fiscal 2028, the load deficit is 500 MW and this increases to 1,250 MW by fiscal 2030.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
Two alternatives were evaluated during Identification phase:
i. Proceed with REV6; and
ii. Defer REV6.
Alternative i. Proceed with REV6 was selected as the preferred alternative based on the 2013 Load Resource Balance (LRB). The project timing has been revised for an In Service Date (ISD) of fiscal 2030 to align with current load growth expectations.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Project Impacts and Benefits: • Provide dependable capacity to meet LRB capacity requirements.	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: "Revelstoke Unit 6, a project to install an additional turbine and related works and equipment at Revelstoke", is an exempt project pursuant to section 7(c) of the *Clean Energy Act*.	

<table>
<tr><td>Investment Planning ID:
G000597</td><td colspan="2">Project Name:
John Hart Generating Station Replacement Project</td></tr>
<tr><td>Forecast Capital Cost:
$1,092.9 million</td><td>Forecast In-Service Date:
Fiscal 2019</td><td>Start Date of Construction:[1]
Fiscal 2014</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference: (Source, July 2017 Appendix J)

2006 IEP – LTAP:
• BCOAPO IR 1.28.1
• TGI IR 2.2.1 Attachment 4

F07/F08 RRA:
• Application, Appendix J
• BCUC IRs 1.5.1 Attachments 1 and 5, 1.83.2
• BCOAPO IR 1.27.2
• IPPBC IRs 1.27.1 and 1.29.1

F09/F10 RRA:
• Application: Appendix I, page 1 and Appendix J, page 28
• BCUC IR 1.5.1, 2.341.1, 2.343.1
• BCOAPO IRs 1.14.1, 2.1.0

F11 RRA:
• Application: Appendix I, page 2, Appendix J, page 32
• BCUC IRs 1.109.2, 1.116.2, 1.199.3, 1.230.2 Attachment 1, 1.257.1, 1.261.1 Attachment 2, 1.265.1 Attachment 1, 1.269.1 Confidential Attachment 1, 1.285.6, 1.331.1 Attachment 1, 1.331.1 Attachment 2, 3.630.1, 3.631.1, 2.398.2, 2.398.4, 2.398.5, 2.401.1 Attachment 1, 2.406.4, 2.459.1, 2.460.1, 2.496.3 Attachment 1, 2.545.5 Attachment 1, 2.2.9 Confidential
• JIESC IR 1.12.4 Confidential Attachment 1, 1.12.4 Attachment 1

John Hart Generating Station Replacement Project CPCN Application
• Decision and Order No. C-2-13

Amended F12-F14 RRA:
• Application: Pages 6-36, 6-37, 6-38; Amended Appendix I, page 12, Amended Appendix J, page 29
• BCUC IRs 1.187.3,.1.197.6, 1.204.1 Attachment 1,1.219 Series,1.220.1, 2.127.1 Series

BC Hydro’s F2014 Annual Report to the BCUC:
• Attachment to Section 8 – Part 2
• Appendix I, line 88
• Appendix J, page 19</td></tr>
</table>

1 Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td></td><td>F17-F19 RRA
• Appendix I, Appendix J, page 2,
• BCUC IRs 1.70.3, 1.82.6 – 1.82.8, 1.170.4, 2.249.8, 2.260.4, 2.283.1.1, 2.307.2, BCSEA IR 1.15.1, CEABC IRs 2.38.1, 2.38.3, 2.40.2, CECBC IR 2.162.1</td></tr>
<tr><td colspan="2">Description:
The purpose of the project is to replace the existing John Hart Generating Station. The age and condition of the John Hart facility indicated the need for significant capital investment in the powerhouse and penstocks to ensure reliable generation from the facility in the long term and to mitigate seismic and environmental risks.
The John Hart Replacement Project includes: replacement of the existing powerhouse with a new three-unit 132.2 MW powerhouse with integrated flow bypass capability. The new facility will provide an additional 11.2 MW dependable capacity (from 121 MW to 132.2 MW).</td></tr>
<tr><td colspan="2">Key Drivers:
• Reliability
• Environmental
• Safety</td></tr>
<tr><td colspan="2">Issues Being Addressed:
The deteriorating condition of the generating facility increased the probability of forced outages with the potential for environmental, safety, and financial impacts.
There was an ongoing risk of flow disruption and impacts to fish and fish habitat in the Campbell River caused by forced outages of the John Hart generating units as there was no adequate flow bypass facility.
The Powerhouse structure did not meet current seismic standards. The wood stave penstocks were located on seismically unstable ground. The existing steel penstocks were also in need of seismic upgrades. The potential consequences of failure could have included injury to employees or the public, environmental damage, disruption of the domestic water supply to the City of Campbell River, and disruption (potentially long term) to plant operations.</td></tr>
<tr><td colspan="2">Discussion of Alternatives:
Please refer to the CPCN Application for a discussion of the alternatives considered.</td></tr>
<tr><td colspan="2">Project Impacts and Benefits:
Project impacts and benefits were summarized in Chapter 2, section 2.2 and Chapter 4, section 8 of the CPCN Application, respectively.</td></tr>
<tr><td>Project Implementation Phase Risk:
Please refer to the John Hart Generating Station Replacement Project Progress Reports to the BCUC for updated risk reporting.</td><td>Risk Treatment:
Please refer to the John Hart Generating Station Replacement Project Progress Reports to the BCUC for updated risk reporting.</td></tr>
<tr><td colspan="2">Additional Information:
On February 8, 2013, the BCUC granted a Certificate of Public Convenience and Necessity (CPCN) for this Project (BCUC Order No. C-2-13).</td></tr>
</table>

Investment Planning ID: **G000656**	**Project Name:** **W.A.C. Bennett Dam Spillway Gate Upgrade**	
Forecast Capital Cost: $47.5 million	**Forecast In-Service Date:** Fiscal 2021	**Start Date of Construction:**[1] Fiscal 2018
Development Phase: Implementation	**Filing Reference:** Amended F12-F14 RRA: • Amended Appendix I, line 76; • Amended Appendix J, page 40 F17-F19 RRA: • Appendix I, line 10, Appendix J page 12, • BCUC IRs 1.70.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1	

Description:

This purpose of this project is to enhance reliability of the existing electrical, mechanical and protection and control equipment of the spillway gate system at the W.A.C. Bennett Dam.

Key Drivers:

- Reliability
- Safety

Issues Being Addressed:

The age, condition and design of the electrical, mechanical, protection and control equipment that support the three radial Spillway Operating gates at G.M. Shrum Generating Facility (**GMS**) do not ensure the reliable and safe operation of the equipment under a wide range of possible conditions. Uncertain outcomes when operating the equipment is due to obsolescence, lack of redundancy in original design, and deficiencies in protection and control systems. Any or all of these factors may result in common-cause or single-point failures that could lead to either inadvertent operation or limits status and alarm indication, making diagnosis of cause more difficult. The project will address 18 identified issues, including condition of the gears and gearbox in the Spillway Operating Gate (**SPOG**) hoist drivetrain, addition of a backup power supply, reliability of gate controls and limit switches, and will mitigate the impacts of inadvertent or uncontrolled gate operation if either should occur.

If the powerhouse is unable to process enough water to limit reservoir elevations due to transmission disruption, post-seismic conditions, unanticipated high inflows or other causes, the only safe way to release this energy is by diverting water down the spillway. This diversion is only possible if the Spillway Operating gates operate on demand.

Discussion of Alternatives:

Four alternatives were considered in Identification Phase to address the deficiencies in the WAC Bennett Dam spillway gate systems:

i. **Do Nothing**;

ii. **Comprehensive project** to address all non-power release facilities at WAC Bennett Dam, including mechanical equipment (spillway gates, low level outlet, and sluice gates), as well as civil infrastructure (the spillway);

iii. **A project to address all aspects of Spillway Operating Gate operation**: including structural integrity, civil components, and mechanical operability, electrical supply, and protection and control concerns; and

iv. **A project limited to Spillway Operating Gate reliability**, and focussing on immediate concerns related to the deteriorated or obsolete equipment in place, as well as design issues that might give rise

[1] Start Date of Construction is the Implementation Approval Date.

to common-cause failures. The scope of this project would be limited to electrical, hoist drive-train mechanical, and P&C issues. Alternative iv, A project limited to Spillway Gate reliability, was selected as the preferred alternative based on a balance of cost and risk-reduction benefits. The first "Do Nothing" alternative was rejected due to the existing identified deficiencies in the SPOG systems, while the second alternative was rejected due to the complexity, costs, and extended delay before it could be undertaken: it will require lengthy studies to determine the best course with both the Sluice Gates and the Low Level Outlet (**LLO**), extending the exposure to the SPOG risks if the three NPR facilities (and possibly the spillway) are combined into a single project. The third alternative, of a comprehensive SPOG rehabilitation project would address all SPOG issues, but would be very expensive, not least due to the need for Single-Device Isolation certification for the spillway stoplogs. It was determined that a limited project as described by the fourth alternative could be implemented at a reasonable cost, while obtaining a significant reduction in the risk that the SPOGs will not operate on demand.
Project Impacts and Benefits: It is anticipated that the Project will fully or partially resolve the following issues including, but not limited to: gear condition, gate control limit switches, gearbox and motor heating systems, reliability of spillway gate controls, alarm on heater failure, hoist rope loading and equalization, and limit switches.

Project Implementation Phase Risk:	**Risk Treatment:**
This project currently does not have any identified Zone 3 Implementation Phase risks	N/A

Additional Information:
N/A

Investment Planning ID: G000011	**Project Name:** Alouette Improve Headworks & Surge Tower Seismic Stability	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Identification	**Filing Reference:** New	

Description:

The purpose of this project is to address seismic deficiencies of the Alouette Dam so that this facility can be relied upon for operations post an earthquake event.

Key Drivers:

- Safety
- Environmental
- Financial Loss
- Reputational

Issues Being Addressed:

The Alouette Dam has been classified as an "Extreme" consequence dam based on BC Dam Safety Regulation. A seismic performance deficiency investigation of the dam and power tunnel was completed in 2011, and it concluded that the spillway would be damaged and cannot be relied upon post maximum design earthquake (**MDE**) to pass the inflow of water. Spilling water through the damaged spillway may lead to its failure and uncontrolled release of water, potentially resulting in fatalities, financial loss, environmental consequences and reputational impact.

With the spillway not being reliable in the event of a MDE, the only means to control elevation in the reservoir would be to use the Alouette power tunnel and adit tunnel to allow a controlled discharge into Stave Lake. The seismic assessment indicated that in the event of a MDE, damage to a number of structures associated with the power tunnel is expected, which could result in the inoperability of the power tunnel and / or adit tunnel. As such, a decision was made to upgrade the power tunnel, and related structures, to ensure safety and reliable operation of Alouette Dam after a MDE.

Discussion of Alternatives:

Three alternatives were evaluated during the Identification Phase:

i. **Do nothing:** defer, either temporarily or permanently, the correction of the seismic deficiencies of the Alouette Dam,
ii. **Upgrade the dam spillway**, and
iii. **Upgrade the power tunnel and related structures,** to allow for water conveyance from Alouette Lake after a MDE.

Alternative iii. Upgrade the power tunnel and related structures was selected as the leading alternative to achieve the project objectives.

Project Impacts and Benefits:

- Improve safety by addressing seismic deficiencies of the power tunnel and related structures, so that this facility can be relied upon for operations post an earthquake event.
- Reduce potential financial loss, environmental consequences and reputational impact due to an uncontrolled release of water from Alouette Reservoir, in the event of a MDE.

[1] Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.
Additional Information:	
N/A	

<table>
<tr><td>Investment Planning ID:
G000657</td><td colspan="2">Project Name:
Comox - Puntledge Flow Control Improvements</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td>Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
BC Hydro’s F2014 Annual Report to the BCUC
• Attachment to Section 8 – Part 2
Appendix I, line 109
Appendix J, page 9
F17-F19 RRA:
• Appendix I, line 15, Appendix J page 16
• BCUC IRs 1.70.3,2.249.8, 2.260.4, BCOAPO IR 1.36.1</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to improve the ability to manage water conveyance at Comox-Puntledge in a controlled and safe manner.</td></tr>
<tr><td colspan="3">Key Drivers:
• Safety
• Reliability
• Environmental
• Financial Loss
• Reputational.</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The water passing through Puntledge Dam goes into one of two parallel watercourses:
• Generation water is conveyed through the power intake and penstock. Most of the water is conveyed through the single turbine to produce power; and
• The balance of the water overflows Puntledge Dam into a public watercourse which is heavily used for recreation, especially in summer.
Appropriate control of both watercourses is imperative for public safety, dam safety, reliable generation and downstream fish migration and habitat. Potential uncontrolled flow impacts could result in fatalities, financial loss and reputational damage.
There are a number of weaknesses within the system which could cause an upset of flow control, such as spurious gate openings or closing, or gates failing to operate on demand at the dam and penstock.
The seriousness of potential public safety issues was highlighted by a June 2002 incident in Ontario when a rarely used gate at the Barrett Chute hydroelectric dam on the Madawaska River was opened to drain off excess water, engulfing a group of sunbathers in a surge of water that swept them over a 10-metre-high cliff. Charges of criminal negligence against Ontario Power Generation and two of its employees were dismissed.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
Eight alternatives were evaluated during Identification Phase, that consisted of various combinations of the following nine “Concept Groups”:
i. Improve Support for Operational Decisions: improve the clarity and certainty in making operational decisions to avoid incidents (such as providing additional tools, training, and data collection and</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

monitoring capability to personnel on site);

ii. **Comox Sluiceway Reliability Improvements:** improve the reliability of the gate controls (such as additional protection and controls equipment and improving the current mechanical gate hoist);

iii. **Generation Conveyance Control System Upgrades:** reduce the probability of a malfunction, lack of function, or other error on the equipment and control systems from the Puntledge intake to the powerhouse (such as improvements to intake trashrack, intake operating gate, fish screen, penstock protection, turbine inlet valve, communication monitoring and control);

iv. **Provide Storage Buffer at Puntledge Diversion Dam:** attenuate the impacts of a stoppage of flow by using available storage in the low gradient Puntledge headpond (such as providing control of discharge at Puntledge Dam in real-time and strengthening the diversion);

v. **Comox Dam Safety Upgrades:** reduce the probability of unusual, very rapid flow increases due to right abutment failure (such as addressing concerns with sloughing of the right bank upstream from the sluiceway and with the robustness to resisting overtopping and piping during extreme floods),

vi. **Modify Puntledge Intake Layout:** Reduce the likelihood of flow control failures in the Puntledge intake and fish screens (such as construction of new fish bypass facilities, new intake bays and penstock work);

vii. **Puntledge Powerhouse By-pass:** Provide flow continuity around the powerhouse (such as construction of a new valve with emergency submerged discharge on the upstream side of the powerhouse);

viii. **Restrict Summer Generation:** Reduce flow control risks; and

ix. **Fully Restrict Generation:** Eliminate flow control risks.

The alternative selected is comprised of Concept Groups i, ii, iii, iv and v above. It was selected as the leading alternative because it meets the project objectives and provides the best balance of flow improvement versus cost to implement. Other combinations of concept groups including Full Restriction are either higher cost than other alternatives that provide an equal or better flow improvement benefit, or provide less flow improvement benefit than alternatives of similar cost. Concept Groups i, ii, iii, iv and v appears at a 'knee' in the cost/benefit curve - to the right of that alternative better scores for flow improvements come at a very high cost, while to the left of and below of the selected relatively small cost reductions are accompanied by relatively large reductions in the flow improvement score.

Project Impacts and Benefits:

- Improve safety by addressing uncontrolled flow at Comox-Puntledge, so that safe downstream recreation can continue.
- Reduce potential financial loss and reputational impact due to uncontrolled flow events.
- Provide long-term operability and maintainability at Comox-Puntledge, at a high level of reliability.
- Minimize environmental risk associated with uncontrolled flow impacts on upstream and downstream fish migration and habitat.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

A related project to improve the public warning sytems for this reach of the Puntledge River was recently implemented to address the unreliability and poor data quality of the Water Level Monitoring System and Public Safety Warning System at Comox-Puntledge. With the exception of the Water Level Monitoring sites at Browns River (Gauge 7), Tsolum River (Gauge 9) and Lewis Park (Gauge 10) the project was placed into service on October 27, 2017. The three final water gauge sites were placed into service on August 1, 2018.

Investment Planning ID: **G000755**	**Project Name:** **Duncan Dam Replace Spillway Gates**	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Identification	**Filing Reference:** F17-F19 RRA: • Appendix I, • BCUC IRs 1.70.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1	
Description: The purpose of this project is to conduct an updated inspection and condition assessment of the Duncan Dam spillway gates to confirm they are fit for purpose and if not provide recommendation for the long-term management of the gates		
Key Drivers: • Safety • Environmental • Financial Loss • Reputational		
Issues Being Addressed: The existing vertical lift spillway gate structures are not designed to facilitate safe maintenance. Their interiors are confined spaces, with asbestos coating and lead paint. Some of the rollers are difficult to access, and challenging to remove for repair or replacement. Due to worker safety risks, proper maintenance has not been carried out over the years, resulting in pervasive corrosion and seized rollers as revealed in recent inspections. Based on a review of the available inspection reports and records of the spillway gate condition in January 2016, Generation Operations site personnel suggested that the spillway gates should not be relied upon for operation beyond five years, unless all re-coating work is completed in accordance with the report (Hatch, 2009; Powertech, 2009) recommendations and a structural engineer confirms that the gates are structurally sound for continued operation. For this reason, it is recommended that the project carry out an updated inspection and condition assessment of the two vertical lift spillway gate structures at Duncan Dam, and to provide recommendations for the long-term management of the gates. The inability to operate the spillway gates would mean that Duncan Dam will have to rely on the two low-level gates for flood routing. Their discharge capacity is inadequate for extreme floods, during which Duncan Dam could overtop potentially resulting in fatalities, environmental impacts and reputational damage. In the event that lack of maintenance renders the spillway gates inoperable (rollers seized) and/or become vulnerable as water barrier (corroded through), the facility will be forced to operate with a much lower maximum normal reservoir level, and may not be able to conform to the Columbia River Treaty (for which Duncan Dam was built). Inability to conform to Columbia River Treaty would lead to significant reputational and financial issues.		

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives: Three alternatives are being evaluated during Identification Phase: i. **Do nothing:** defer any work on the spillway gate structures until 2028, and continue only with monitoring / inspection; ii. **Limited refurbishment** to achieve life extension of the existing gates; and iii. **Replacement** of existing gates. The project is currently in Needs Stage, and an updated inspection and condition assessment was undertaken in 2018. The report will assess the three alternatives and provide recommendations for the long-term management of the gates.	
Project Impacts and Benefits: • Improve safety with gates that are seismically resilient, capable to withstand overtopping, safe and reasonably easy to maintain, inspect and test. • Reduce potential financial loss, environmental consequences and reputational impact by improving the ability to pass water in the event of an extreme flooding even. • Reduce potential reputational impact and financial loss from inability to conform to the Columbia River Treaty, in the event of having to operate with a much lower maximum normal reservoir level.	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: N/A	

<table>
<tr><td>Investment Planning ID:
G000585</td><td colspan="2">Project Name:
John Hart Dam Seismic Upgrade</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td>Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
Amended F12-F14 RRA:
• Application: Amended Appendix I, Page 13, Amended Appendix J, page 57
• BCUC IR 1.205.1 Attachment 1, 1.219.10 Attachment 1, 2.127.1
BC Hydro’s F2014 Annual Report to BCUC:
• Attachment to Section 8 – Part 2
Appendix I, line 98
Appendix J, page 18
F17-F19 RRA:
• Appendix I, line 13, Appendix J, page 13,
• BCUC IRs 1.70.3,1.73.1, 1.73.9, 1.82.1 – 1.82.9, 1.86.6, 2.249.8, 2.260.4, CEABC IRs 1.17.1 - 1.17.5, 2.39.1 – 2.39.4, 2.40.1, 2.40.2, BCOAPO IRs 1.36.1, 1.36.2, CECBC IRs 1.90.1, 2.156.1</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to address seismic deficiencies of the John Hart Dam so that this facility can be relied upon for post-earthquake operation.</td></tr>
<tr><td colspan="3">Key Drivers:
• Safety
• Financial
• Reputational</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The John Hart Dam is classified as an Extreme consequence dam and therefore the expected seismic performance is for no uncontrolled release for the Maximum Design Earthquake (MDE). A seismic performance investigation was carried out and it was determined that the withstand of the various component dams and spillway gate system is less than the MDE. Damage from a seismic event could lead to uncontrolled release of water from the reservoir, potentially resulting in fatalities, financial loss and reputational damage. Therefore, seismic upgrades to the dam and spillway gates system are required.
In addition to the seismic-related deficiencies, there is a risk of overtopping the John Hart dam due to unplanned generation flow imbalance between John Hart and the upstream Ladore facility. A free overflow spillway is planned to address this concern.
The scope of this project includes the design and construction of the following:
• Upgrades to the Middle Earthfill dam and Power Intake Dam;
• Upgrades to the North Earthfill dam;
• Upgrades to the concrete dam, including incorporation of a free overflow spillway; and
• Upgrades to the spillway gates system.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives: Four alternatives are being evaluated: i. **Do nothing:** defer, either temporarily or permanently, the correction of the seismic deficiencies of the John Hart Dam. Could include an interim response plan such as: including availability of 24/7 electricians post-earthquake to control operation of the dam or improving instrumentation at the dam such as addition of cameras in an effort to be able to provide a more rapid evaluation of the state of the dam post-earthquake; ii. **Decommission** the dam; iii. **Permanently lower the reservoir** to reduce loading on the dam; and iv. **Upgrade** the John Hart Dam**,** to ensure: a) no uncontrolled release of reservoir following a MDE; and b) the dam suffers only minor damage such that an immediate deep or prolonged drawdown is not required to maintain post-seismic river flow control. Alternative iv. Upgrade the John Hart Dam was selected as the leading alternative as this is the only alternative that satisfies dam safety requirements. Alternative ii Decommission will not be consistent with the implementation of the John Hart Replacement Project. Alternative iii permanently lowering the reservoir elevation has economic and environmental consequences, as it reduces generation at the John Hart Generating Station due to the reduced head, and exposes the currently inundated reservoir areas. More importantly, on further investigations it was determined that reducing the reservoir elevation would not improve the seismic withstand of the Dam, and nor would it materially reduce the consequences of a Dam failure; hence, reservoir lowering does not represent an adequate response to the current condition of the Dam. The project also considers Special Direction 10.6(2) (February 3, 2012), "In deciding whether to issue a certificate to the authority under section 46 of the Act for the John Hart Generating Station Replacement Project, the commission must assume that the authority requires, in order to meet its electricity supply obligations, the 806 gigawatt hours per year of firm energy and 128 megawatts of dependable capacity that the project is capable of delivering by 2018 and continuing to deliver over the expected life of the project."
Project Impacts and Benefits: • Improve safety by addressing seismic deficiencies of the John Hart Dam so that this facility can be relied upon for post-earthquake operation. • Avoid potential financial loss and reputational impact due to an uncontrolled release of water from the reservoir, in the event of an MDE.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information: As the planning level estimate for this project is over $100 million, BC Hydro expects that BCUC approval will be required for this project. Planning is currently underway for upgrades at the upstream Strathcona and Ladore facilities (Strathcona Discharge Upgrade Project, G000525; and Ladore Spillway Seismic Upgrade Project, G000668). Planning for these two projects is being considered in conjunction with the John Hart Dam Seismic Upgrade project for the following reasons: • The projects are planned with similar and potentially overlapping construction schedules; • The projects are relatively close geographically to one another; • The projects have some similar scope elements that will require similar contractor expertise; and • The projects all reside on the Campbell River and the work will need to be considered from a river system management perspective and coordinated accordingly. The project teams will develop an Integrated Regulatory Strategy for the three projects.

<table>
<tr><td colspan="1">Investment Planning ID:
G000668</td><td colspan="2">Project Name:
Ladore Spillway Seismic Upgrade</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td>Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
Amended F12-F14 RRA:
• Amended Appendix I, line 118; Amended Appendix, page 62
BC Hydro’s F2014 Annual Report to the BCUC:
• Attachment to Section 8 – Part 2
Appendix I, line 118
Appendix J, page 22
F17-F19 RRA:
• Appendix I, line 14, Appendix J, page 15
• BCUC IRs 1.70.3,1.86.1-1.86.4.1, 1.86.5, 1.86.6, 2.249.6, 2.258.1 to 2.258.6, 2.260.4
• BCOAPO IRs 1.36.1, 2.80.1</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to address seismic deficiencies of the Ladore Dam so that this facility can be relied upon for post-earthquake operation.</td></tr>
<tr><td colspan="3">Key Drivers:
• Safety
• Financial
• Reputational</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Ladore Dam is classified as an Extreme consequence dam and therefore the expected seismic performance is for no uncontrolled release for the Maximum Design Earthquake (MDE). A seismic performance investigation was carried out, and it was determined that the withstand of the spillway gates and hoist structure is less than the MDE, and damage could lead to an uncontrolled release of water from the reservoir. Failure of the Ladore gates could lead to a flow imbalance at John Hart Dam, located about 1 km downstream, with potential for overtopping of the John Hart Dam, potentially resulting in fatalities, financial loss and reputational damage.
The scope of this project includes upgrades to the Ladore spillway to ensure that:
• In the event of a MDE, the spillway and water conveyance system act as an integral water barrier to retain the Ladore Reservoir;
• The spillway can release water in a controlled manner after a seismic event up to MDE; and
• Electromechanical systems that operate the spillway have an acceptable level of reliability.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives:

Three alternatives were evaluated during Identification Phase:

i. **Refurbishment** of gates, towers and hoists;

ii. **Replacement** of gates and **refurbishment** of towers and hoists; and

iii. **Replacement** of gates, towers and hoists.

Alternative iii Replacement of the spillway gates, towers and hoists was selected as the leading alternative. Alternative iii. is considered to be the best long term solution because it will provide a more reliable and robust design, increase the ease of maintenance and safety for BC Hydro operation staff, and reduce environmental impacts during and after construction.

Project Impacts and Benefits:

- Improve safety by addressing seismic deficiencies of the Ladore Dam, so that this facility can be relied upon for post-earthquake operation.
- Reduce potential financial loss and reputational impact due to an uncontrolled release of water from the reservoir, in the event of an MDE.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

As the planning level estimate for this project is over $100 million, BC Hydro expects that BCUC approval will be required for this project.

Planning is currently underway for upgrades at the upstream Strathcona facility and downstream John Hart facility (Strathcona Discharge Upgrade Project, G000525; and John Hart Dam Seismic Upgrade Project, G000585). Planning for these two projects is being considered in conjunction with the Ladore Spillway Seismic Upgrade project for the following reasons:

- The projects are planned with similar and potentially overlapping construction schedules;
- They are relatively close geographically to one another;
- They have some similar scope elements that will require similar contractor expertise; and
- They all reside on the Campbell River and the work will need to be considered from a river system management perspective and coordinated accordingly.

The project teams will develop an Integrated Regulatory Plan for all three projects.

<table>
<tr><td>Investment Planning ID:
G000525</td><td colspan="2">Project Name:
Strathcona Upgrade Discharge</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td>Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• Appendix I, line 17, Appendix J, page 17
• BCUC IRs 1.70.3, 1.73.1, 1.73.9, 1.87.1-1.87.6, 2.249.8, 2.259.1, 2.259.2,2.260.4, BCOAPO 1.36.1,1.36.2, 2.80.1, 2.80.2, 2.81.1, CECBC IR 2.156.1</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to provide deep reservoir drawdown capability at Strathcona Dam to mitigate dam safety risks associated with seismic events and seepage deficiencies of the dam, and to enable potential future projects to be undertaken to upgrade the dam itself.</td></tr>
<tr><td colspan="3">Key Drivers:
• Safety
• Financial
• Reputational</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Strathcona Dam is classified as an Extreme consequence category dam and therefore the expected seismic performance is for no uncontrolled release for the Maximum Design Earthquake (MDE). Strathcona Dam has seismic and seepage deficiencies and there is no means of enacting a deep reservoir drawdown. Also, there are reliability and seismic issues with the existing gated spillway that may limit the ability to operate on demand or cause it to fail following a seismic event. In a post-seismic event, there is a potential that the intake gates may not be able to be closed, pressurizing the power intake tunnel underlying the dam, which could result in further damage to the dam or result in uncontrolled release of water. Uncontrolled water release from the reservoir could create significant risk to life and damage to downstream residents, as water would flow downstream toward the City of Campbell River, overtopping and damaging both Ladore and John Hart dams, as the Lower Campbell and John Hart reservoirs are not large enough to contain such a release. This type of event could potentially result in fatalities, financial loss and reputational damage.
The provision of a new Low Level Outlet (LLO), with a new inlet founded on a rock abutment rather than in the earth dam itself, will not only provide emergency deep drawdown of the reservoir, but will allow for future decommissioning of the current intake and water passage, which will provide further protection to the dam.
The project scope also includes conversion of the existing gated spillway to a free-crest spillway at a higher elevation. This conversion will eliminate the need to refurbish the existing spillway gates and reinforce the spillway piers. Ordinary spillway functionality will be provided by sizing the LLO to allow current spillway volumes.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives:

Four alternatives were evaluated during Identification Phase:

i. **Construct a LLO**;
ii. **Build a seismically robust power system:** relocation of current power conduit;
iii. **Rehabilitate existing dam**; and
iv. **Construct a new downstream dam**.

Alternative i Construct a LLO was identified as the leading alternative. It provides dam safety risk reduction at the lowest cost and with the fastest delivery. The project team determined that the LLO should be the first alternative implemented, with a power conduit and dam rehabilitation to follow as future conditions dictate. Alternative iii is not viable as a stand alone project due to the need for reservoir control during construction, but would be viable after either LLO or new powerhouse project is in place. Alternative iv is not economically justified and requires LLO prior to construction.

Project Impacts and Benefits:

- Improve safety by partially addressing seismic deficiencies of the Strathcona Dam, so that this facility can be relied upon for post-earthquake operation.
- Reduce potential financial loss and reputational impact due to an uncontrolled release of water from the reservoir in the event of an earthquake.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

As the planning level estimate for this project is over $100 million, BC Hydro expects that BCUC approval will be required for this project.

Planning is currently underway for upgrades at the downstream John Hart and Ladore facilities (John Hart Dam Seismic Upgrade Project, G000585; and Ladore Spillway Seismic Upgrade Project, G000668). Planning for these two projects is being considered in conjunction with the Strathcona Discharge Upgrade project for the following reasons:

- The projects are planned with similar and potentially overlapping construction schedules,
- The projects are relatively close geographically to one another,
- The projects have some similar scope elements that will require similar contractor expertise, and
- The projects all reside on the Campbell River and the work will need to be considered from a river system management perspective and coordinated accordingly.

The project teams will develop an Integrated Regulatory Plan for all three projects.

Investment Planning ID: **G003554**	**Project Name:** **W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates**	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Identification	**Filing Reference:** F17-F19 RRA: • Appendix I, line 23, • BCUC IRs 1.70.3, 1.85.1 to 1.85.7, 2.249.8, 2.260.4, BCOAPO IR 1.36.1	

Description:

The primary objective of the Project is to address the dam safety risks posed by the deteriorating condition of the sluice gates on the spillway of the W.A.C. Bennett Dam, including considering rehabilitating or decommissioning some or all of the sluice gates.

Key Drivers:

- Safety
- Financial Loss
- Reputational

Issues Being Addressed:

At the time the W.A.C. Bennett Dam was built, there were two intended functions of the sluiceways and slide gates:

i. The spillway, including the contribution from the sluiceways, was designed for a maximum flood level capacity of 325,000 cubic feet per second (**cfs**), including flood inflows from the McGregor River Diversion. The McGregor River Diversion was not constructed and is prohibited under the Clean Energy Act passed in 2010. Without the McGregor River Diversion, the sluiceways are not needed to pass the design flood;

ii. The slide gates were designed to provide compensation flow release during and after the reservoir filling period, and were apparently included in the design to relieve the low level outlets from operation as early as practical. Once the reservoir reached the elevation where the spillway gates could provide the minimum flow release, this back-up role was transferred to the spillway gates.

All nine slide gates have been inoperable since 1987 after issues with opening the gates were experienced as well as leakage after closure. Subsequent inspections have revealed further deterioration of components of the slide gates.

The slide gate bonnet covers are in Poor condition. There is a risk that one or more of the bonnet covers may fail, which would result in uncontrolled water release from the slide gate gallery to the drainage tunnels running below the earth filled dam. The drainage tunnels connect to both the powerhouse and the low level outlets, are generally unlined and are only intended to handle drainage and provide access.

Leakage or failure of one or more of the slide gates would also result in uncontrolled water release to the spillway chute, which may prevent inspection, repair and maintenance of the spillway chute, and ultimately may impair flood discharge capability.

Single device isolation (**SDI**) certification of all nine slide gates is required to access the spillway chute for inspection and maintenance. Continued SDI certification in the longer term will become more difficult and eventually will require refurbishment or replacement of the slide gates or decommissioning the gates to eliminate the hazard.

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives:

Three alternatives were evaluated during Identification Phase:

i. **Do nothing:** the condition and leakage on the slide gates and bonnet covers will continue to be monitored. Decommissioning of the sluiceways or refurbishment (or replacement) of the slide gates and bonnet covers deferred into the future;

ii. **Decommission** nine sluiceways**.** The sluiceways will be plugged with reinforced concrete downstream of the slide gates and the slide gate gallery will be partially filled with reinforced concrete, embedding the slide gate hydraulic cylinder assembly and bonnet covers;

iii. **Rehabilitate** six sluiceways. This alternative recommissions two of the three sluiceways in each of the three spillway bays. For the sluiceways to be recommissioned, the slide gates and hydraulic cylinders will be refurbished or replaced, the slide gate control cabinet will be replaced, and the downstream surfaces of the sluiceways will be repaired. The remaining sluiceways will be permanently decommissioned with a reinforced concrete plug upstream of the slide gate.

Alternative ii, Decommission nine sluiceways, was selected as the leading alternative because it addresses dam safety risks, minimizes capital expenditure, and avoids future inspection, operation and maintenance efforts.

Project Impacts and Benefits:

- Improve safety by addressing deteriorating condition of the sluiceways and slide gates.
- Reduce potential financial loss and reputational impact due to an uncontrolled release of water from the reservoir.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

There are two concurrent projects that may be impacted by this project:

- W.A.C. Bennett Dam Seal Low Level Outlets (G003555)

  This project will decommission the low level outlets under the W.A.C. Bennett Dam. The work will likely involve backfilling by concrete plugs and removing equipment. The project is currently in the Conceptual Design Stage. The targeted project in-service date is January 2024. While resource and laydown conflicts are not anticipated, the projects will coordinate to ensure that any overlaps in construction timing are managed effectively.

- W.A.C. Bennett Dam Spillway Gate Upgrade (G000656)

  This project is implementing upgrades to the spillway operating gates, which are located in the same spillway headworks structure as the sluiceways and slide gates. The “Recommission / Seal Spillway Sluice Gates (G003554)” project team has therefore scheduled its Feasibility field investigations to avoid interfering with spillway operating gate construction planned for F2020, and will coordinate all investigations through the Construction and Contract Management team.

Investment Planning ID: G003555	**Project Name:** GMS Seal Low Level Outlets	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Identification	**Filing Reference:** F17-F19 RRA: • Appendix I, line 24, Appendix J, page 18, • BCUC IRs 1.70.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1	

Description:

The purpose of this project is to safely decommission the three low level outlets under the W.A.C. Bennett Dam to mitigate the hazard (uncontrolled water release from the reservoir) posed by long-term deterioration of the low level outlets.

Key Drivers:

- Safety
- Financial Loss
- Reputational

Issues Being Addressed:

Three low level outlets (**LLOs**) are located beneath the embankment dam, in rock, in the diversion tunnels that were used to divert Peace River during dam construction. The inlets to the tunnels are located at a depth of about 160 m below the surface of the maximum normal operating level of Williston Reservoir. The LLOs were designed as temporary discharge devices for use during first filling and were not intended for use as discharge devices at normal reservoir operating levels. The LLOs are currently out-of-service and regular testing and inspections are not carried out due to worker safety concerns. The condition of these assets, almost 50-years old, is deteriorating, making them a potential hazard to the dam. An uncontrolled release of water due to component structural failures would eventually result in damage to the dam if the flow was not shut off. Such a release would be very difficult to curtail given the high head and depth of the LLOs.

Discussion of Alternatives:

Four alternatives were evaluated prior to the start of this project, as part of a long term strategy for the future role of the LLOs in the operation of the W.A.C. Bennett Dam:

i. **Do Nothing:** maintain the status quo or deferral;
ii. **Refurbishment** of the existing LLOs for flow release as currently designed;
iii. **Re-purposing** the LLOs for reservoir evacuation capability or for installation of additional generating units; and
iv. **Decommissioning** (either permanently or with the option to re-open the LLOs at some time in the future).

Alternative iv, decommissioning, was selected as the only viable alternative. Do Nothing is not considered an acceptable response given the age of the LLOs and their deteriorated condition which would eventually lead to a component failure and uncontrolled release of the reservoir behind an Extreme Consequence dam. No future operating scenario was identified that warrants the refurbishment of the existing LLOs for flow release as currently designed. Based on an engineering study, the technical feasibility of the re-purposing option is uncertain and near term project drivers and/or benefits were not identified.

[1] Start Date of Construction is the Implementation Approval Date.

Project Impacts and Benefits:

- Reduce safety risks by decommissioning the LLOs.
- Reduce potential financial loss and reputational impact due to an uncontrolled release of water from Williston Reservoir.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

There are two concurrent projects that may be impacted by this project:

- W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates (G003554):

  This project will address the dam safety risks posed by the deteriorating condition of the sluiceways and slide gates on the spillway of the W.A.C. Bennett Dam. The project is currently in the Conceptual Design Stage. The targeted project in-service date is November 2022. While resource and laydown conflicts are not anticipated, the projects will coordinate to ensure that any overlaps in construction timing are managed effectively; and
- W.A.C. Bennett Dam Spillway Gate Upgrade (G000656):

  This project is implementing upgrades to the spillway operating gates, which are located in the same spillway headworks structure as the sluiceways and slide gates. The “Recommission / Seal Spillway Sluice Gates (G003554)” project team has therefore scheduled its Feasibility field investigations to avoid interfering with spillway operating gate construction planned for fiscal 2020, and will coordinate all investigations through the Construction and Contract Management team.

Investment Planning ID: G000556	**Project Name:** Hugh Keenleyside - Spillway and Low Level Outlets Concrete Upgrade	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Future	**Filing Reference:** New	

Description:

The objective of this project is to upgrade the damaged concrete structures of the Hugh Keenleyside Dam's spillway and low level outlets, restoring them to original or near-original condition. This upgrade will extend these structures' service lives and permit a wider range of operational options relating to the passage of water over and through the dam.

Refer to Appendix K – Hugh Keenleyside Facility Asset Plan for additional information.

Key Drivers:

- Financial
- Reliability

Issues Being Addressed:

- Since the dam was put into operation in 1968, there has been localized loss of concrete to the spillway and low level outlets due to erosion, abrasion and cavitation. Reinforcing bars are exposed in a number of locations. Low Level Outlets 1 and 4 have sustained the largest amount of damage and are close to the point of being taken out of service.
- Due to loss of concrete in some locations, rates of damage progression are unpredictable, and there is the potential need for a portion of the spillway or low level outlet to be taken out-of-service with little or no advance notice. In this event, immediate repairs implemented under urgent or emergency conditions would be required.
- With the benefit of modern numerical hydraulic modelling, we have implemented operational changes that restrict use of the low level outlets which are expected to slow (but not stop) the progression of damage. The operational changes, however, have reduced operational flexibility in passing flows.
- Maintenance and repairs to the concrete have been carried out over the years, but with limited success. Due to the progression of damage, the required frequency, extent, and cost of repairs (largely underwater) is expected to grow with diminishing effectiveness.

Discussion of Alternatives:

- The option of retaining the status quo and continuing to operate and maintain the spillway and low level outlets as at present is not sustainable, as:
  - Repairs are expected to become increasingly expensive and decreasingly effective over time;
  - These structures comprise a critical safety feature of the dam and cannot be run to failure; and
  - The point in time at which these structures will no longer be fit for safe use cannot be predicted.
- Owing to Hugh Keenleyside Dam's importance to the Columbia River system and its role under the terms of the Columbia River Treaty, decommissioning of the dam or temporarily taking it out of service from a water storage perspective is not viable.

The single remaining viable alternative is to upgrade the concrete structures of the spillway and low level outlets by replacing the damaged portions of reinforced concrete, restoring their condition to as close to "new" as possible. This upgrade is required before the damage progresses to the point where the low level outlets and/or the spillway must be taken out-of-service. The upgrade will require either underwater work or the construction of temporary cofferdams to allow construction "in the dry".

[1] Start Date of Construction is the Implementation Approval Date.

Project Impacts and Benefits:

- Extended life of the spillway and low level outlet structures.
- Reduction of anticipated maintenance costs and outages.
- Elimination of concerns that a sudden progression of damage will force some or all of these discharge facilities to be taken out of service, requiring even more costly interventions under urgent or emergency conditions.
- Increased flexibility of operations to pass flows that preserve the integrity and service life of the structure while mitigating environmental impacts.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

Operations at Hugh Keenleyside Dam have international impacts on flow regulation, power generation and flood control under the terms of the Columbia River Treaty.

Investment Planning ID: G003365	**Project Name:** Mica - Discharge Facilities Seismic and Reliability Upgrades	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Future	**Filing Reference:** New	

Description:

Mica Dam discharge facilities include both a three-gated spillway and a two-gated outlet works. The objective of this project is to upgrade these discharge facilities to provide for continued safe containment of the reservoir during an earthquake, safe discharge of water from the reservoir after such an earthquake, and sufficiently reliable operation for all other service conditions, including during periods of high inflows up to extreme floods.

Refer to Appendix K – Mica Facility Asset Plan for additional information.

Key Drivers:

- Safety
- Reliability

Issues Being Addressed:

- The design earthquake has been updated since the dam's design and construction and demands from the current design earthquake exceeds the original design capacities. Seismic deficiencies have been identified in various spillway and outlet works structures. Moreover, the gates' mechanical, electrical, control and power supply equipment has not been seismically qualified and cannot be relied upon to operate after an earthquake. Inability to safely operate the discharge facilities after an earthquake:
  - Would preclude a drawdown of the reservoir for dam inspections, repairs or other emergency measures; and
  - Could lead to eventual overtopping of the earthfill dam, resulting in erosion and possible dam failure.

  The discharge facilities require a general and extensive seismic upgrade in order that their post-earthquake operability can be relied upon.
- The discharge gates at Mica Dam do not have sufficient reliability to sufficiently ensure operability when needed during periods of high inflows and reservoir levels, such as during freshet and floods. Failure of the discharge facilities to operate during or after floods could lead to eventual overtopping of the earthfill dam, resulting in erosion and possible dam failure. Operational reliability improvements to the gate systems in accordance with current BC Hydro principles—including mechanical, electrical, control and power supply sub-systems—are required in order that they can be relied upon to operate when needed.

Discussion of Alternatives:

Given the safety and reliability issues identified and the extreme consequences of a failure at Mica Dam, long-term retention of the status quo is not acceptable. The only viable alternative is to upgrade the deficient components to meet the current seismic and operational reliability requirements. Specific scope items will be determined in the project's Identification Phase.

[1] Start Date of Construction is the Implementation Approval Date.

Project Impacts and Benefits: • Assured reservoir containment up to and including extreme earthquakes and provision of safe and reliable post-earthquake discharge and drawdown capability to allow for dam inspection, repairs and other emergency measures, as required. • Increased operational reliability to reasonably assure discharge function and prevent dam overtopping during high inflows up to and including extreme flood events.	
Project Implementation Phase Risk: This project is not yet in Implementation.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: Mica Dam provides flow regulation, power generation and flood control under the terms of the Columbia River Treaty.	

<table>
<tr><td>Investment Planning ID:
G000492</td><td colspan="2">Project Name:
Bridge River 2 Upgrade Units 5 and 6</td></tr>
<tr><td>Forecast Capital Cost:
$86 million</td><td>Forecast In-Service Date:
Fiscal 2019</td><td>Start Date of Construction:[1]
Fiscal 2017</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
F07/F08 RRA:
• BCUC IR 1.193.0 Attachment 1
• BCUC IR 2.347.0 Attachment 1
F09/F10 RRA:
• Application: Appendix I, page 1; Appendix J, page 9
F11 RRA:
• Application, Appendix I, page 3; Appendix J, pages 55 and 56
• BCUC IRs 1.192.2, 1.192.3, 1.331.1 Attachment 1 and 2, 2.406.3, 2.545.5 Attachment 1
Amended F12-F14 RRA:
• Application: Amended Appendix I, page 12; Amended Appendix J, page 36
• BCUC IRs 1.200.0, 1.204.1 Attachment 1, 1.211.0
BC Hydro’s F2014 Annual Report to the BCUC:
• Attachment to Section 8 – Part 2
Appendix I, line 108
Appendix J, page 3
F17-F19 RRA:
• Appendix I, line 34, Appendix J, page 22,
• BCUC IRs 1.70.3, 1.88.1 – 1.88.10, 2.249.8, 2.260.4, BCOAPO IRs 1.36.1, 1.64.3</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to restore the reliability of the Unit 5 and 6 generators and other related equipment, and to restore lost water conveyance capacity within the Bridge River system.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Environmental
• Reputational</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Issues Being Addressed:

The primary drivers for this project are the lost capacity, unacceptable condition and unreliability of the Bridge River 2 Generating Units 5 and 6.

The Generating Station is in Poor condition. The Equipment Health Rating of the generators is Unsatisfactory. Both generators have been de-rated by 32 per cent due to multiple winding insulation failures. There is a high risk of further winding failures, which would result in an unplanned unit outage of up to 18 months.

The Equipment Health Rating of the governors is Poor due to their condition, life expectancy, high rate of oil leakage in the distributing valve, and lack of spare parts. Similarly, the unit circuit breakers are rated Poor due to significant wear, lack of spare parts, and declining technical support. The exciters are also rated Poor due to degradation, age and difficulty in obtaining technical support.

The operating regime for both Bridge River 1 and 2 has been impacted by a Dam Safety requirement from February 2015 to lower the maximum elevation of the upstream Downton Reservoir to manage LaJoie Dam seismic safety risks. This change in operations means there is 50 per cent less storage in Downton Reservoir, resulting in increased seasonal inflow to Carpenter Reservoir. Reduced capability to divert water from Carpenter Reservoir to Seton Lake, via the Bridge River generating stations, has increased the likelihood and magnitude of spills from Terzaghi Dam to the Lower Bridge River beyond the Water Use Plan Order (**WUP Order**) targets for annual average flows and those same targets set forth in settlement agreements with the St'át'imc Nation. BC Hydro has been, and currently is, operating under a variance to our Water Use Plan order, approved by the Comptroller of Water rights (February 16, 2017).

Discussion of Alternatives:

Alternatives evaluated during Identification phase:

i. **Do nothing:** Replace components as they fail;

ii. **Minimum refurbishment:** Replace the stator winding, stator core and rotor pole insulation; no uprate of the generators would be achieved. Other equipment required for reliable operation (e.g., governors, circuit breakers, exciters) would also be replaced;

iii. **Refurbish the generators with increased capacity:** Replace most generator components (e.g., stator frame, winding, cores; and rotor insulation, poles, winding) and reuse other generator components (e.g., rotor rim, spider, shaft). Other equipment required for reliable operation would also be replaced (similar to minimum refurbishment); and

iv. **Replace the generators with increased capacity:** Replace all stator and rotor components. Other equipment required for reliable operation would also be replaced (similar to minimum refurbishment).

Alternative iv Replace the generators with increased (historical) capacity (75 MW) was selected as the preferred alternative as it provides a long-term (50 years) improvement to generator reliability, improves water management on the Bridge and Seton Rivers, restores the units historical operating capacity, and is the lowest risk from a construction and future operating perspective.

Project Impacts and Benefits:

- Improve reliability of Bridge River 2 Units 5 & 6.
- Extend the service life of the main generator components by at least 50 years.
- Improve the operating capability at Bridge River 2 Units 5 & 6 from a total of 96 MW to a total of 150 MW (75 MW per unit).
- Provide reliable water conveyance capacity within the Bridge River system.
- Reduce the likelihood and magnitude of spills from Terzaghi Dam to Lower Bridge River, in order to minimize potential effects on fish, riparian habitat, and First Nations values.
- Maintain BC Hydro's relationship with the St'at'imc Nation.
- Reduce potential reputational impact due to spill events.

Project Implementation Phase Risk;	**Risk Treatment;**
If the completion of the Units is significantly delayed into 2019, there is a risk of increased spilling in the Lower Bridge River.	• Drawdown reservoirs prior to the outage. • BC Hydro will continue to engage St'át'imc regarding project status and potential impact on flows. • Monitor progress of construction and accelerate if needed.
Additional Information: The project will be constructed considering the planned outages for Bridge River 2 maintenance and other projects. The Bridge River System lies within the traditional territory of the St'át'imc Nation. BC Hydro and St'át'imc have a set of Agreements (signed in 2011) that settle all past, present and future claims related to the Bridge River facilities and provide legal certainty around continued operations of the Bridge River facilities and inform ongoing relationship development. BC Hydro is engaging the St'át'imc Nation in a manner consistent with our Agreements and continues to work with the St'át'imc to address issues and concerns around this project.	

<table>
<tr><td colspan="1">Investment Planning
ID: G000614</td><td colspan="2">Project Name:
Cheakamus Units 1 and 2 Generator Replacement</td></tr>
<tr><td>Forecast Capital Cost:
$74.2 million</td><td>Forecast In-Service Date:
Fiscal 2020</td><td>Start Date of Construction:[1]
Fiscal 2015</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:

F07/F08 RRA:
• Application: pages 7-65 and 7-76
• BCUC IR 2.347.00 Attachment 1

F09/F10 RRA:
• Application: Appendix I, page 1; Appendix J, page 12

F11 RRA:
• Application: Appendix I, page 2; Appendix J, page 37
• BCUC IRs 1.192.2, 1.192.3, 2.537.1, 1.257.1, 1.265.1 Attachment 1, 1.331.1 Attachment 1, 2.406.3, 2.537.1, 2.537.2 Attachment 1, 2.545.5 Attachment 1, 2.552.2, 2.2.9 Confidential
• JIESC IRs 1.12.4 Confidential Attachment 1, 2.27.1 Attachment 1;
• CECBC IR 1.9.3 Attachment 1

Amended F12-F14 RRA:
• Application: Amended Appendix I, Page 12, Amended Appendix J, Page 36
• BCUC IRs 1.204.1 Attachment 1, 1.219.6 Attachment 1

BC Hydro’s F2014 Annual Report to the BCUC
• Attachment to Section 8 – Part 2
Appendix I, line 84
Appendix J, page 5

F17-F19 RRA:
• Appendix I, line 28, Appendix J, page 20,
• BCUC IRs 1.70.3, 1.89.1 – 1.89.4, 2.249.8, 2.260.4, 2.307.4, BCOAPO IR 1.36.1</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to replace the two generators at Cheakamus which are in Poor condition. The project will also result in an increase in operating capacity from 70 MW to 90 MW for each unit.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Issues Being Addressed: Inspection and testing of one of the generators in 2006 identified three areas of concern: stator core waves, hot spots and sole plate cracking. The two generators were assigned a Poor Equipment Health Rating in 2012 and 2013. Some of the issues which adversely affect the health rating include high stator winding insulation leakage current, deterioration of the stator and rotor insulation, stator core waves, and bearing oil leaks. A failure of a stator winding would likely result in an unplanned unit outage of up to 18 months and lost opportunity costs.	
Discussion of Alternatives: Three alternatives were evaluated during Identification phase: i. **Do nothing:** replace the stator winding, stator core and rotor pole insulation at failure; ii. **Refurbish** the generators via replacement of the stator core, stator winding and rotor pole insulation; no uprate of the generators would be achieved; and iii. **Replace** the generators with increased capacity. Replacing the generators with increased capacity was selected as the preferred alternative based on a net present value analysis and is being implemented.	
Project Impacts and Benefits: • Improve reliability of the generators. • Increase operating capacity from 70 MW to 90 MW for each unit.	
Project Implementation Phase Risk: This project currently does not have any identified Zone 3 (high) Implementation Phase risks.	**Risk Treatment:** N/A
Additional Information: N/A	

<table>
<tr><td>Investment Planning ID:
G000127</td><td colspan="2">Project Name:
G.M. Shrum G1 to 10 Control System Upgrade</td></tr>
<tr><td>Forecast Capital Cost:
$75.0 million</td><td>Forecast In-Service Date:
Fiscal 2023</td><td>Start Date of Construction:[1]
Fiscal 2018</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
Amended F12-F14 RRA:
• Application: Amended Appendix I, Page 12; Amended Appendix J, Pages 101 to 103
BC Hydro’s F2014 Annual Report to the BCUC:
• Attachment to Section 8 – Part 2
Appendix I, line 91
Appendix J, page 10
F17-F19 RRA:
• Appendix I, Appendix J page 24,
• BCUC IRs 1.70.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1</td></tr>
<tr><td colspan="3">Description:
This purpose of this project is to modernize Units 1 to 10 control systems, replace Units 6 to 10 governor control systems, replace Units 9 and 10 exciters, replace the controls for plant auxiliary systems, and replace the control room controls at G.M. Shrum Generating Facility (GMS).</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The GMS Units 6 to 8 governors have an Equipment Health Rating (EHR) of Poor due to the tendency of the analog controls to drift out of calibration, limited technical support, governor frequency control being out of specification during standardized tests, and limited availability of spare parts. The Unit 9 analog governor has an EHR of Poor due to the forced outages attributed to the governor, limited technical support and limited spare parts availability. The Unit 10 analog governor, which is from the same manufacturer as Unit 9, has an EHR of Fair.
The GMS Units 9 and 10 Westinghouse Rapcon exciters have analog controls and are based on obsolete technology. Unit 9 has an EHR of Fair, and Unit 10 has an EHR of Poor. Concerns include component failures, limited availability of spare parts, and limited technical support.
Concerns on all the equipment to be replaced include lack of vendor support due to system age, limited or no availability of spare parts, units drifting off settings due to control deficiencies, and unit outages caused by component failure or misoperation.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
The GMS Controls Upgrade Project Team considered three alternatives:
i. Full-scope,
ii. Controls-only scope, and
iii. Deferral.- continue to operate GMS (and Peace Canyon Generating Facility) in their current condition
Alternative i. Full-scope was selected because it minimizes the total outage time and avoids the need to design and implement interfaces between new and old technology. The project was broken into three identified tranches of work, with a separate approval for each tranche.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date for all Tranches of this project.

- Tranche 1: Units 1 to 5 controls and plant Local Area Network (completed);
- Tranche 2: Units 6 to 10 controls, Units 6 to 10 governor controls, and Units 9 to10 exciters (in Implementation); and
- Tranche 3: Spillway, switchyard and intake controls, and GM Shrum control room (in Implementation).

This approach allows lessons learned on earlier tranches to be adopted in subsequent tranches. More importantly, each tranche will be estimated and scheduled shortly before it enters Implementation Phase, based on current supplier and market understanding, and avoids a commitment to cost and schedule targets over a decade in the future.

It was recognized that due to the long duration of the project, control improvements could be available during the course of the project. BC Hydro has implemented a strategy of evaluating the benefits of any changes in controls, and if warranted, adopts a new control approach both prospectively and retrospectively, updating completed work to match any newly adopted designs. This strategy balances the advantages of new or improved technology with the benefits of standardization across all units in the plant.

Project Impacts and Benefits:

- Allows both local and remote operation of both GMS and the Peace Canyon generating stations.
- Governors on Units 6 to10 and exciters on Units 9 to10 will be new, improving availability of both spares and vendor support.
- New controls and control room will improve the operators' situational awareness and ability to respond to problems.

Project Implementation Phase Risk:	**Risk Treatment:**
There is a risk that the equipment currently deployed by the Generating Operational Asset Architecture Logic (**GOAAL**) standard will not provide the functionality to support the required plant control room alarm management features	This is being avoided by evaluating commercially available Supervisory Control and Data Acquisition (**SCADA**) control packages for the new plant control room design with the intention of including this alarm management capability in the GOAAL standard

Additional Information:

N/A

<table>
<tr><td>Investment Planning ID:
G003207</td><td colspan="2">Project Name:
Mica Replace Units 1 to 4 Generator Transformers</td></tr>
<tr><td>Forecast Capital Cost:
$82.1 million</td><td>Forecast In-Service Date:
Fiscal 2023</td><td>Start Date of Construction:[1]
Fiscal 2018</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• Appendix I, line 67, Appendix J, page 34
• BCUC IRs 1.70.3, 1.92.1-1.92.3, 2.249.8, 2.260.4
• BCOAPO IR 1.36.1</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to replace twelve single-phase generating unit transformers at the Mica Generating facility with explosion-resistant transformers for safe and reliable operation.</td></tr>
<tr><td colspan="3">Key Drivers:
• Safety
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
Twelve single-phase transformers connect the Unit 1 to 4 Mica generators to the transmission network by stepping up the generator output voltage of 16 kV to transmission voltage of 500 kV. The reliability and safety risks associated with these transformers are increasing as the assets age and degrade.
The Equipment Health Rating (EHR) of 10 of the transformers is Poor. After nearly 40 years of service, several of the transformers are showing signs of overheating while others have indications of insulation degradation. The Mica transformers are located in an underground powerhouse, and a failure presents a safety risk for people working in the underground powerhouse in addition to the reliability risks associated a forced outage.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
Three alternatives were considered during Identification Phase:
i. Do nothing: replace transformers at failure;
ii. Refurbishment and partial replacement; and
iii. Replace with new single phase explosion-resistant transformers.
Alternative iii. Replace with new single phase explosion-resistant transformers was recommended as the preferred alternative for the following reasons:
• The Mica Units 5 and 6 Project and Mica GIS Replacement Project have already evaluated the risks associated with working near live oil filled transformers in the underground facility at Mica. This work resulted in the selection of an explosion-resistant transformer design for the new Mica Units 5 and 6;
• Full replacement of the Mica 1 to 4 generator step up transformers is the only technically feasible alternative that met the project objectives; and
• BC Hydro has recently awarded a Master Supply Agreement (MSA) to a vendor for the supply of transformers. This project will be able to take advantage of this MSA as it includes the specifications for explosion-resistant transformers.</td></tr>
<tr><td colspan="3">Project Impacts and Benefits:
• Improve transformer reliability.
• Reduce safety risk.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk:	**Risk Treatment:**
Due to the age of the old transformers, and the work taking place underground while some other units are operating and energized, there is a risk of serious worker injury or fatality in the event of a transformer explosion in the underground chamber.	To mitigate this risk, the project will develop a Safety Plan (conforming with BC Hydro's Contractor Safety Program) and utilize the procedures, knowledge and experience gained from the Mica GIS and Mica 5 and 6 projects as both of these projects performed work in the transformer chamber with energized transformers.
Additional Information:	
N/A	

<table>
<tr><td>Investment Planning ID:
G003362</td><td colspan="2">Project Name:
Mica Townsite Augment Accommodations Capacity</td></tr>
<tr><td>Forecast Capital Cost:
$23.3 million</td><td>Forecast In-Service Date:
Fiscal 2020</td><td>Start Date of Construction:[1]
Fiscal 2018</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• Appendix I, line 54
• BCUC IRs 1.70.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to address the expected housing shortage at Mica Creek and to provide a long-term accommodation solution to support future capital projects housing needs.</td></tr>
<tr><td colspan="3">Key Drivers:
• Financial</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Mica facility is in a remote location, approximately 130 km north of the town of Revelstoke. The Mica Townsite, owned by BC Hydro, consists of a number of permanent buildings for staff accommodation and recreation. The buildings were originally built in the 1960s, and house approximately 50 staff who maintain and operate the plant on an on-going basis.
Additionally, in 2011, a temporary construction camp was built and leased to BC Hydro at the townsite to accommodate up to 400 temporary additional staff working on large capital projects at the Mica facility. The construction camp was scheduled to be removed in 2015 after completing the installation of Units 5 and 6 at Mica. However, with the timing of current and planned capital projects at Mica, there is a need to modify and extend the life of the camp to accommodate project related staff over the next 10 to 15 years.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
Three alternatives were evaluated during Identification phase:
i. Purchase portions of the temporary Mica 5 and 6 dormitory units and the camp kitchen/dining area and renovate them. (This renovated kitchen and dining area is separate from the current main Townsite kitchen and dining area used by existing plant personnel);
ii. Purchase portions of the temporary Mica 5 and 6 dormitory units and renovate them; and expand the existing Townsite kitchen and dining area to accommodate these additional users, for a single kitchen/dining solution; and
iii. Build new accommodation units and expand the existing Townsite kitchen and dining area to accommodate these additional users, for a single kitchen/dining solution.
Alternative ii, Purchase portions of the temporary Mica 5 and 6 dormitory units and renovate them, and expand the existing Townsite kitchen and dining area, was recommended as the preferred alternative as it was the lowest cost alternative and provided a single kitchen solution that re-uses existing dormitory units.</td></tr>
<tr><td colspan="3">Project Impacts and Benefits:
• Deliver long-term solution to accommodation shortage at Mica Creek.
• Support long-term strategy of a consolidated Townsite.</td></tr>
<tr><td>Project Implementation Phase Risk:
This project currently does not have any identified Zone 3 (high) Implementation Phase risks</td><td colspan="2">Risk Treatment:
N/A</td></tr>
<tr><td colspan="3">Additional Information:
N/A</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td>Investment Planning ID:
G003542</td><td colspan="2">Project Name:
Mica Upgrade Powerhouse Cranes</td></tr>
<tr><td>Forecast Capital Cost:
$36.1 million</td><td>Forecast In-Service Date:
Fiscal 2020</td><td>Start Date of Construction:[1]
Fiscal 2018</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• Appendix I, line 57, Appendix J, page 32,
• BCUC IRs 1.70.3, 2.249.8, 2.260.4
• BCOAPO IR 1.36.1</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to upgrade the main powerhouse cranes at the Mica Generating Facility to lift a generator rotor.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The primary drivers for the Project are: 1) the age and poor condition of the existing cranes and runway support structures; and 2) the requirement for two powerhouse cranes, each with a rated load capacity of 525 tons, to lift a generator rotor. Currently, the existing powerhouse cranes have been de-rated to a load capacity of 315 tons each and are inadequate for lifting a generator rotor.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
The following three alternatives were assessed in Identification Phase:
i. Install only the cranes;
ii. Install the cranes and perform runway structure upgrades; and
iii. Do nothing or defer the Project.
Alternative ii, Install the cranes and perform runway structure upgrades, was selected as the preferred alternative as it was the only alternative that would meet the maximum lifting load requirements in the Mica powerhouse.
The new cranes will reduce the risk of control system failure caused by overheating, fire and age related degradation of components. The existing electrical and control systems on the Mica powerhouse cranes are original from when the cranes were installed in 1974 and have reached end of life. As well, safety will be improved with the new cranes as they have braking redundancy, variable speed control and tandem lift synchronization.</td></tr>
<tr><td colspan="3">Project Impacts and Benefits:
This Project will increase the lifting capacity of the powerhouse cranes to 525 tons which will enable the powerhouse cranes to meet the maximum lifting load capacity requirements at Mica. The new crane and runway upgrade are expected to significantly reduce the outage duration if there is a rotor failure.</td></tr>
<tr><td>Project Implementation Phase Risk:
This project currently does not have any identified Zone 3 (high) Implementation Phase risks</td><td colspan="2">Risk Treatment:
N/A</td></tr>
<tr><td colspan="3">Additional Information:
N/A</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: **G000057**	**Project Name:** **Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)**	
Forecast Capital Cost: $45.4 million to $25.7 million	**Forecast In-Service Date:** Fiscal 2023	Start Date of Construction:[1] TBD
Development Phase: Definition	**Filing Reference:** BC Hydro's F2014 Annual Report to the BCUC: • Attachment to Section 8 – Part 2 Appendix I, line 120 Appendix J, page 4 F2017-F2019 RRA: • Appendix I, Appendix J page 30, • BCUC IRs 1.70.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1	

Description:

The purpose of this project is to strip the old failed coatings on the exterior and interior steel surfaces of Cheakamus penstocks 1 and 2, and steel lined tunnel, and recoat them with a new coating system to prevent further corrosion, and extend the life of the penstocks and tunnel.

Key Drivers:

- Reliability
- Safety
- Financial

Issues Being Addressed:

The protective coatings on the exterior and interior of the Cheakamus steel penstocks and steel tunnel liner are exhibiting signs of coating failure. The Equipment Health Rating (**EHR**) is rated as Unsatisfactory.

Without recoating, the extent of corrosion will increase to the the point where recoating is no longer an option and a penstock replacement is required. Over time, continued corrosion will impact the structural integrity of the steel material, impacting the penstock's ability to reliably and safely convey water to the Cheakamus generating units.

Discussion of Alternatives:

The following alternatives were considered in Identification phase:

i. **Do Nothing and Monitor**;
ii. **Strip and Recoat Exterior Surface of Steel Penstocks**;
iii. **Strip and Recoat Exterior and Interior Surfaces of Steel Penstocks**; and
iv. **Complete Replacement of Steel Penstocks**.

Alternative iii. Strip and Recoat Exterior and Interior Surfaces of Steel Penstocks was selected as the preferred alternative as it would address safety and reliability objectives, and extend the penstock life. Alternative i (Do Nothing) or Alternative ii (Strip and Recoat Exterior Penstock Surfaces) would not deliver a significant overall penstock life extension because corrosion of the uncoated and unprotected steel penstock sections would not be achieved. Loss of steel would persist, potentially undermining the structural integrity of the penstock, which are considered high pressure vessels conveying significant volumes of water and are key water passage components used for generation. Penstock failures may cause extensive economic and infrastructure damage.

[1] Start Date of Construction is the Implementation Approval Date.

Project Impacts and Benefits: • Improve equipment reliability and safety. • Extend asset (penstock and steel tunnel) life.	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: Cost savings due to reduced mobilization and de-mobilization are expected to be realized by recoating all exterior and interior surfaces as part of one project.	

<table>
<tr><td>Investment Planning ID:
G000114</td><td colspan="2">Project Name:
G.M. Shrum Upgrade HVAC System</td></tr>
<tr><td>Forecast Capital Cost:
$22 million to $13 million</td><td>Forecast In-Service Date:
Fiscal 2023</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Definition</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• Appendix I,
• BCUC IRs 1.70.3. 2.249.8, 2.260.4, BCOAPO IR 1.36.1</td></tr>
</table>

Description:

The purpose of the G.M. Shrum (**GMS**) Upgrade Heating Ventilation and Air Conditioning (**HVAC**) System project is to address the degrading condition of the HVAC system at the G.M. Shrum Generating Facility.

Key Drivers:

- Reliability
- Safety

Issues Being Addressed:

The project will address the reliability risk of forced unit outages due to HVAC system failures. Recent forced outage reports have indicated that heating systems in the Circuit Breaker Buildings may be a contributing cause to improper operation of the unit circuit breakers. In addition, the cooling coils and related piping for the Low Voltage Lead Shaft powerhouse supply fans are nearing end of life and have been a source of water leaks. Although the HVAC system is classified as an ancillary system, it has impacts to the reliable and safe operation of units at the GMS Generating Facility.

Discussion of Alternatives:

Three alternatives were considered during Identification phase:

i. **Limited Refurbishment** of HVAC System,
ii. **Modernization** of HVAC System, and
iii. **Modernization and Selected Upgrades** of HVAC system.

Alternative iii Modernization (like for like modern equivalent replacements) and Selected Upgrades (upgrade to improve performance of certain components) of the HVAC System was selected as the preferred alternative as it will meet the project objectives of improving reliability, and reducing worker safety risks.

Project Impacts and Benefits:

- Improve reliability by reducing forced outages
- Reduce worker safety risks

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when project reaches Implementation.

Additional Information:

N/A

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td>Investment Planning
ID: G000640</td><td colspan="2">Project Name:
Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment</td></tr>
<tr><td>Forecast Capital Cost:
$48.8 million to $21.0 million</td><td>Forecast In-Service Date:
Fiscal 2022</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Definition</td><td colspan="2">Filing Reference:
F11 RRA:
• Application: Appendix I, Page 3; Appendix J, Page 51
Amended F12 – F14 RRA:
• Application: Appendix I, line 101; Appendix J, page 42
F17-F19 RRA:
• Appendix I, line 39, Appendix J, page 26,
• BCUC IRs 1.70.3, 2.249.8, 2.260.4, BCOAPO IRs 1.36.1, 1.64.4</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to address water conveyance reliability risks associated with the tunnel from Coquitlam Reservoir to Lake Buntzen Reservoir.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Safety</td></tr>
<tr><td colspan="3">Issues Being Addressed:
There are two Intake Operating Gates located in the tunnel to control flow. In addition, one Intake Maintenance Gate is provided for isolating the two Intake Operating Gates and the tunnel. Tunnel isolation is required to complete inspections and maintenance of the tunnel and Intake Operating Gates.
The Intake Operating Gates are original equipment (1908 and 1911) and are in poor condition. The operating gates have experienced failures due to broken rollers and wire ropes and have experienced difficulties opening under high head conditions. Failure of these gates impact BC Hydro’s ability to convey water between the Coquitlam Reservoir and Lake Buntzen. In heavy rain events, this may impact BC Hydro's ability to mitigate downstream flooding in the Coquitlam River and impact BC Hydro’s ability to operate the Lake Buntzen generating facility.
This project will also address issues with the Intake Maintenance Gate and re-certify the gate so that it can be used for Single Device Isolation.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
The following alternatives were considered in the Identification phase:
i. Do nothing: continue to repair the gates as they fail;
ii. Replace Gates: Replace two Intake Operating Gates at the existing location and install the Intake Maintenance Gate at a new location;
iii. Replace Gates in New Location: Enlarge the Intake Operating Gates vertical access shaft and replace the concrete pier to provide a new location for two new Intake Operating Gates and replace the Intake Maintenance Gate with two new gates at the existing location of the two Intake Operating Gates;
iv. Replace Operating Gates and Maintenance Gate: Replace the two Intake Operating Gates and the Intake Maintenance Gate at their existing locations and refurbish the existing Intake Maintenance Gate concrete gate wall; and</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">v. Refurbish: Refurbish the mechanical parts of the two Intake Operating Gates at their existing locations to achieve a 15-year service life, including re-use of gate system components; and replace the Intake Maintenance Gate at its existing location and refurbish the existing Intake Maintenance Gate concrete gate wall.
Alternative v. Refurbish the two Intake Operating Gates and replace the Intake Maintenance Gate, all at their existing locations, was selected as the preferred alternative. This alternative balanced factors such as cost and business risks of spills due to gate failure.</td></tr>
<tr><td colspan="2">Project Impacts and Benefits:
• Improve reliability of the Coquitlam-Buntzen Tunnel gates.
• Reduce public and worker safety hazards.</td></tr>
<tr><td>Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="2">Additional Information:
N/A</td></tr>
</table>

<table>
<tr><td>Investment Planning ID:
G000172</td><td colspan="2">Project Name:
Mica Modernize Controls</td></tr>
<tr><td>Forecast Capital Cost:
$62.9 million to $36.2 million</td><td>Forecast In-Service Date:
Fiscal 2024</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Definition</td><td colspan="2">Filing Reference:
F17-F19 RRA
• Appendix I, line 52, Appendix J, page 31
• BCUC IRs 1.70.3, 1.91.1 – 1.91.4, 2.249.8, 2.260.4, BCOAPO 1.36.1.</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to modernize the original Mica Unit 1 to 4 analog unit and control room controls, alarms and metering; replace the excitation systems; upgrade the governor controls; and replace the unit protection equipment.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Mica Unit 1 to 4 control room equipment; unit protection and control equipment; exciter, and governor controls are all approaching end of life. The control room equipment and exciters are no longer supported by suppliers making it increasingly difficult to maintain and obtain spare parts.
The original electromechanical unit protection systems are in Poor condition and there is an increased risk that the protection relays may fail to operate during an electrical fault.
A major failure of either the governor or exciter could result in a generator forced outage of the affected unit for up to 12 months.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
Three alternatives were evaluated during Identification phase:
i. Do Nothing and Defer: maintain and replace Units 1 to 4 controls as they fail;
ii. Refurbish: refurbish and life extend Units 1 to 4 controls on selected sub-systems; and
iii. Replacement: replace Units 1 to 4 controls including exciters, governor controls, unit controls, control room controls, remote controls and power distribution switchboards.
Alternative iii Replacement was selected as the preferred alternative. This alternative was the only technically feasible alternative that meets the project objectives of reliability, maintainability and operability.</td></tr>
<tr><td colspan="3">Project Impacts and Benefits:
• Improve Protection & Control Reliability
• Improve Exciter Reliability</td></tr>
<tr><td colspan="2">Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="3">Additional Information:
N/A</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: G000241	Project Name: Puntledge Recoat Interior and Exterior of Steel Penstock	
Forecast Capital Cost: $55.9 million to $31.7 million	**Forecast In-Service Date:** Fiscal 2022	**Start Date of Construction:**[1] TBD
Development Phase: Definition	**Filing Reference:** BC Hydro's F2014 Annual Report to the BCUC: • Attachment to Section 8 – Part 2 Appendix I, Appendix J, page 26 F19-F19 RRA: • Appendix I, line 59, Appendix J page 33, • BCUC IRs 1.70.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1	

Description:

The purpose of this project is to address safety and reliability risks associated with the Puntledge Generating Station penstock, and achieve an asset life extension through a strip and recoat intervention.

Key Drivers:

- Reliability
- Safety
- Financial

Issues Being Addressed:

The penstock at the Puntledge Generating Station has been in-service since 1954. The long steel penstock sections are exhibiting signs of coating failure. The Equipment Health Rating (**EHR**) for the long steel sections of the penstock is Unsatisfactory.

Without recoating, the extent of corrosion damage will increase and, over time will impact the structural integrity of the steel material to the point where recoating is no longer an option and a penstock replacement is required. Continued corrosion may require the penstock to be removed from service when it is no longer safe to operate.

Discussion of Alternatives:

The following alternatives were considered in the Identification phase:

i. **Do Nothing and Monitor**;
ii. **Strip and Recoat Only Exterior Surface of Steel Penstocks**;
iii. **Strip and Recoat Exterior and Interior Surfaces of Steel Penstocks**; and
iv. **Complete Replacement of Penstocks**.

Alternative iii Strip and Recoat Exterior and Interior Surfaces of Steel Penstocks is the preferred alternative. It would address safety and reliability objectives, and extend the penstock life. Alternative i (Do Nothing) or Alternative ii (Strip and Recoat Exterior Penstock Surfaces) would not deliver a significant overall penstock life extension because corrosion of the uncoated and unprotected steel penstock sections would not be achieved. Loss of steel would persist, potentially undermining the structural integrity of the penstock, which are considered high pressure vessels conveying significant volumes of water and are key water passage components used for generation. Penstock failures may cause extensive economic and infrastructure damage.

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">Project Impacts and Benefits:
• Extend penstock life.
• Improve equipment reliability and safety.</td></tr>
<tr><td>Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="2">Additional Information:
The water conveyed by the approximately five km penstock is also used by the Comox Valley Regional District, and by Fisheries and Oceans Canada (DFO). Given the penstock’s proximity to municipalities, and DFO’s reliance on the water conveyed by the penstock, it is important that the safety and reliability of the penstock be sustained.</td></tr>
</table>

<table>
<tr><td colspan="1">Investment Planning ID:
G000342</td><td colspan="2">Project Name:
Wahleach Recoat Penstock (Interior and Exterior)</td></tr>
<tr><td>Forecast Capital Cost:
$38.5 million to $21.8 milion</td><td>Forecast In-Service Date:
Fiscal 2021</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Definition</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• Appendix I,
• BCUC IRs 1.70.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1</td></tr>
</table>

Description:

The purpose of this project is to address safety and reliability risks associated with the Wahleach Generation Facility (**WAH**) penstock and achieve an asset life extension through a strip and recoat intervention.

Key Drivers:

- Reliability
- Safety
- Financial

Issues Being Addressed:

The original WAH steel penstock sections are over 60 years old. The steel sections of the penstocks are exhibiting signs of coating failure. The Equipment Health Rating (**EHR**) for the steel sections of the penstock is rated as Unsatisfactory.

Without recoating, the extent of corrosion damage will increase to the point where recoating is no longer an option and a penstock replacement is required. Continued corrosion may also eventually impact the structural integrity of the steel material. Safe and reliabile operation is important, as the WAH facility is close to key infrastructure, including railway lines, pipelines and the Trans-Canada Highway, which could be impacted by a penstock failure.

Discussion of Alternatives:

The following alternatives were considered in Identification Phase:

i. **Do Nothing** and Monitor,
ii. **Strip and Recoat Only Exterior** Surface of Steel Penstocks,
iii. **Strip and Recoat Exterior and Interior** Surfaces of Steel Penstocks, and
iv. **Complete Replacement** of Penstocks**.**

Alternative iii, Strip and Recoat the Exterior and Interior Surfaces Steel Penstocks, was selected as the preferred alternative as it would address safety and reliability objectives and extend the penstock life by up to 20 years at a lower cost than the Complete Replacement alternative. Alternative i (Do Nothing) or Alternative ii (Strip and Recoat Exterior Penstock Surfaces) would not deliver a significant overall penstock life extension because corrosion of the uncoated and unprotected steel penstock sections would not be achieved. Loss of steel would persist, potentially undermining the structural integrity of the penstock, which are considered high pressure vessels conveying significant volumes of water and are key water passage components used for generation. Penstock failures may cause extensive economic and infrastructure damage.

Project Impacts and Benefits:

- Improve equipment reliability and safety
- Extend penstock life

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1 Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: N/A	

<table>
<tr><td>Investment Planning ID:
G000334</td><td colspan="2">Project Name:
Wahleach Refurbish Generator</td></tr>
<tr><td>Forecast Capital Cost:
$67.6 million to $22.0 million</td><td>Forecast In-Service Date:
Fiscal 2022</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Definition</td><td colspan="2">Filing Reference:
New</td></tr>
<tr><td colspan="3">Description:
The purpose of the project is to improve the reliability of the generator at Wahleach Generating Facility.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Equipment Health Rating (EHR) for the Wahleach generator rotor and stator is Poor. Failure of the generator would result in an unplanned outage ranging from six to 24 months.
There is no water bypass at Wahleach which means that if the generator is not operating, the only means of evacuating water from the reservoir is by free spilling over the dam into Jones Creek. Spilling into Jones Creek may lead to erosion of the spillway channel and increases the risk of flooding the community of Laidlaw.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
The following four alternatives were assessed in Identification Phase:
i. Do nothing: Defer,
ii. Rotor Pole Replacement: Replace the rotor poles and retain the rotor spider and rim,
iii. Generator Refurbishment: Replace the stator and rotor poles and refurbish the remaining generator components); and
iv. Generator Replacement: Replace the entire generator.
Alternative iii, Generator Refurbishment, is the preferred alternative because it is the most cost effective solution based on an NPV analysis that will meet the project objectives of ensuring reliable operation of the generator for 40 to 50 years.</td></tr>
<tr><td colspan="3">Project Impacts & Benefits:
• Extend generator life by at least 40 years.</td></tr>
<tr><td colspan="2">Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when project reaches Implementation.</td></tr>
<tr><td colspan="3">Additional Information:
N/A</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: G000485	**Project Name:** Bridge River 1 - Strip and Recoat Penstocks 1-4 Interior	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Identification	**Filing Reference:** New	

Description:

The purpose of this project is to ensure safe and reliable operation of the four steel penstocks at the Bridge River 1 Generating Facility for another 40 years by addressing the active corrosion of the interior which is resulting in loss of metal thickness and strength.

Key Drivers:

- Reliability
- Safety
- Financial

Issues Being Addressed:

The internal coating system on all four penstocks at Bridge River 1 (**BR1**) is failing with significant defects throughout the coated surface. The Equipment Health Rating for the penstocks is Unsatisfactory and they are showing signs of coating failure and corrosion. Stripping and recoating the penstocks will extend their useful life.

If no action is taken, the interior penstock surfaces will corrode. Over time, this will undermine the structural integrity and safety of the penstocks. The penstocks would then need to be replaced when they are no longer safe to operate.

Discussion of Alternatives:

Three alternatives will be evaluated during Identification Phase:

i. **Do nothing:** monitor the corrosion and replace penstocks when no longer safe to operate,
ii. **Defer project** until the next outage opportunity, and
iii. **Strip and recoat penstock interior during a planned outage.**

Project Impacts and Benefits:

- Reduce financial loss by carrying out essential stripping and recoating work during an already planned outage.
- Improve safety by addressing deteriorating condition of the penstocks.
- Reduce potential financial loss due to an uncontrolled release of water from the reservoir.

Project Implementation Phase Risk	**Risk Treatment**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

To minimize lost opportunity costs associated with a long unit outage, it would be beneficial to coordinate with the planned unit refurbishment outage windows for the generator upgrade planned from fiscal 2022 to fiscal 2025.

The Bridge River System lies within the traditional territory of the St’át’imc Nation. BC Hydro and St’át’imc have a set of Agreements (signed in 2011) that settle all past, present and future claims related to the Bridge River facilities and provide legal certainty around continued operations of the Bridge River facilities and inform ongoing relationship development. BC Hydro is engaging the St’át’imc Nation in a manner consistent with our Agreements and continues to work with the St’át’imc to address issues and concerns around this project.

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: **G000776**	**Project Name:** **Bridge River 1 Replace Units 1-4 Generators / Governors**	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Identification	**Filing Reference:** BC Hydro 2014 Annual Report to the BCUC • Attachment to Section 8 – Part 2 Appendix I, page line 139 Appendix J, page 2 F17-F19 RRA • Appendix I, Appendix J, page 28 • BCUC IRs 1.70.3, 2.249.8, 2.260.4 • BCOAPO IR 1.36.1	
Description: The purpose of the project is to improve generation reliability due to the Poor and Unsatisfactory health conditions of the Bridge River 1 Generating Facility Units 1 to 4 generators and related equipment, and to provide reliable water conveyance capacity within the Bridge River system.		
Key Drivers: • Reliability • Environmental • Reputational		
Issues Being Addressed: The four generators in the Bridge River 1 plant are in Poor to Unsatisfactory condition. Unit 4 was re-wound in 1977 but was de-rated after a stator winding failure during testing in 2011. The de-rating of Unit 4 restricts the water flow through the unit, limiting water conveyance capabilities. In addition to the loss in operating capability due to the de-rating of Bridge River 1 Unit 4, the operating regime for both Bridge River 1 and 2 has been impacted by a Dam Safety requirement from February 2015 to lower the maximum elevation of the upstream Downton Reservoir to manage LaJoie Dam seismic safety risks. This change in operations means there is 50 per cent less storage in Downton Reservoir, resulting in increased seasonal inflow to Carpenter Reservoir. Reduced capability to divert water from Carpenter Reservoir to Seton Lake, via the Bridge River generating stations, has increased the likelihood and magnitude of spills from Terzaghi Dam to the Lower Bridge River beyond the Water Use Plan Order (**WUP Order**) targets for annual average flows and those same targets set forth in settlement agreements with the St'át'imc Nation. BC Hydro has been, and currently is, operating under a variance to our Water Use Plan order, approved by the Comptroller of Water rights (February 16, 2017).		

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives:

Four alternatives were evaluated during the Identification Phase:

i. **Do Nothing:** maintain the existing units and replace the generators and other related components upon failure;
ii. **Rewind** the generator stators and replace or refurbish other components, as needed, to ensure each unit can maintain its original 50 MW rating;
iii. **Refurbish** the generators and replace the exciters and governors to match the current capacity of the turbines and operate within the limitations of the existing physical plant and constraints of the existing Water Use Plan Order; and
iv. **Replace** the generators, exciters and governors to match the current capacity of the turbines and operate within the limitations of the existing physical plant and constraints of the existing Water Use Plan Order.

Alternative iv, Replace the generators, exciters and governors, was selected as the leading alternative because it offers improvements to generator reliability and water management capabilities. This alternative also has the longest service life, more extensive warranties from the manufacturer, and minimizes the likelihood of additional scope from as-found conditions that would risk extending the outage schedule and increasing costs versus the refurbish alternative. In addition, this alternative allows for the full utilization of the licensed flow amounts through the generator and management of the Water License Order targets from Terzaghi Dam into the Lower Bridge River.

Project Impacts and Benefits:

- Improve generation reliability by replacing the Units 1 to 4 generators and related equipment;
- Provide reliable water conveyance capacity within the Bridge River system.
- Reduce the likelihood and magnitude of spills from Terzaghi Dam to Lower Bridge River, in order to minimize potential effects on fish, riparian habitat, and First Nations values.
- Maintain BC Hydro's relationship with the St'at'imc Nation.
- Reduce potential reputational impact due to spill events.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when this project reaches Implementation.

Additional Information:

This project, and reinforcement to the transmission system will ensure generation can be delivered at all times of the year in the Bridge River Area, without additional spill at Terzaghi Dam into Lower Bridge River and at Seton River. The reinforcement work is being carried out through the Bridge River Transmission Project (92423).

As the planning level estimate for this project is over $100 million, BC Hydro expects that BCUC approval will be required for this project.

The Bridge River System lies within the traditional territory of the St'át'imc Nation. BC Hydro and St'át'imc have a set of Agreements (signed in 2011) that settle all past, present and future claims related to the Bridge River facilities and provide legal certainty around continued operations of the Bridge River facilities and inform ongoing relationship development. BC Hydro is engaging the St'át'imc Nation in a manner consistent with our Agreements and continues to work with the St'át'imc to address issues and concerns around this project.

<table>
<tr><td>Investment Planning ID:
G000493</td><td colspan="2">Project Name:
Bridge River 2 Upgrade Units 7 and 8</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td>Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• Appendix I, line 44, Appendix J, page 29,
• BCUC IRs 1.70.3, 1.88.1 – 1.88.10, 2.249.8, 2.260.4, BCOAPO 1.36.1</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to restore the reliability of the Unit 7 and 8 generators and other related equipment, and to restore lost water conveyance capacity within the Bridge River system.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Environmental
• Reputational</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The primary drivers for this project are the lost capacity, unacceptable condition and unreliability of the Bridge River 2 generating Units 7 and 8. Bridge River 2 generating Units 7 and 8 were placed into service in 1960. Both Units 7 and 8 were de-rated after an age-related stator winding failure on Unit 6 in 2011. In addition, Unit 8 was further de-rated in 2015 after experiencing a fault. The equipment de-rating restricts the water flow through the units, limiting water conveyance capabilities.
As of April 2018, the Unit 7 generator has a Poor and Unit 8 generator has an Unsatisfactory Equipment Health Rating. A failure of a major component could result in an unplanned unit outage of up to 18 months.
Operating regime for both Bridge River 1 and 2 has been impacted by a Dam Safety requirement from February 2015 to lower the maximum elevation of the upstream Downton Reservoir to manage LaJoie Dam seismic safety risks. This change in operations means there is 50 per cent less storage in Downton Reservoir, resulting in increased seasonal inflow to Carpenter Reservoir. Reduced capability to divert water from Carpenter Reservoir to Seton Lake, via the Bridge River generating stations, has increased the likelihood and magnitude of spills from Terzaghi Dam to the Lower Bridge River beyond the Water Use Plan Order (WUP Order) targets for annual average flows and those same targets set forth in settlement agreements with the St’át’imc Nation. BC Hydro has been, and currently is, operating under a variance to our Water Use Plan order, approved by the Comptroller of Water rights (February 16, 2017).</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
Three alternatives were evaluated during the Identification Phase:
i. Do nothing: repair or replace equipment at failure,
ii. Refurbish generators with a system output of 71 MW per unit, and
iii. Replace generators with a system output of 75 MW per unit.
Alternative iii Replace generators with a system output of 75 MW per unit was selected as the leading alternative as it addresses all project objectives and provides the greatest financial benefit.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Project Impacts and Benefits:	
• Improve generator reliability and restore lost firm capacity of 30 MW. • Provide reliable water conveyance capacity within the Bridge River system. • Reduce the likelihood and magnitude of spills from Terzaghi Dam to Lower Bridge River, in order to minimize potential effects on fish, riparian habitat, and First Nations values. • Maintain BC Hydro's relationship with the St'at'imc Nation. • Reduce potential reputational impact due to spill events.	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when project reaches Implementation.
Additional Information: The Bridge River System lies within the traditional territory of the St'át'imc Nation. BC Hydro and St'át'imc have a set of Agreements (signed in 2011) that settle all past, present and future claims related to the Bridge River facilities and provide legal certainty around continued operations of the Bridge River facilities and inform ongoing relationship development. BC Hydro is engaging the St'át'imc Nation in a manner consistent with our Agreements and continues to work with the St'át'imc to address issues and concerns around this project.	

Investment Planning ID: **000952**	**Project Name:** **Kootenay Canal Modernize Controls**	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Identification	**Filing Reference:** F17-F19 RRA: • BCUC IR 1.73.1, BCOAPO IR 1.36.2	

Description:

The purpose of this project is to improve the long-term reliability, maintainability and operability of the control systems, exciters and governors for all four generating units at Kootenay Canal Generating Station.

Key Drivers:

- Reliability

Issues Being Addressed:

Reliability, technical support and spare parts obsolescence increase the reliability risks associated with the control systems, exciters and governors. Over the past 10 years, Kootenay Canal Generating Station has experienced auxiliary control relay failures, and has experienced five forced outages in the past two years due to the aged control relays, indicating the relays are nearing end of design life.

The exciters are based on obsolete technology and have analogue controls that are reaching end of industry life expectancy (40 years). This model of exciter is no longer manufactured nor technically supported, and spare parts are no longer available from the manufacturer

The governor controls are original and have obsolescence issues (except for the mechanical speed switches which were replaced in 2014). Spare parts are not available from the manufacturer and there is minimal technical support. A failure of the hydraulic control valves may result in an extended outage while parts are reverse engineered.

Discussion of Alternatives:

Three alternatives are being evaluated for the control systems, exciters and governors during Identification Phase:

i. **Do nothing:** continue operating the units under current condition until fail;
ii. **Refurbish:** retains 40-plus-year old design practices which in many cases does not reflect current standards for safety, and does not increase functionality of existing equipment; equipment refurbishment requires custom fabrication or reverse-engineering of obsolete components, and raises issues about future spare part and technical support availability; and
iii. **Replace** the unit control, exciter and governor controls.

Additionally, three alternatives for the unit AC/DC Power Distribution Boards and Governor Mechanical systems are being evaluated during Identification Phase.

i. **Do Nothing:** continue operating the units with current condition and maintain and replace components as they fail;
ii. **Refurbish** system components to extend service life; and
iii. **Replace** system components to extend service life.

Project Impacts and Benefits:

- Improve the long-term reliability, maintainability and operability of the control systems, exciters and governors.

[1] Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.
Additional Information:	
N/A	

<table>
<tr><td>Investment Planning ID:
G000741</td><td colspan="2">Project Name:
Ladore - Redevelop Unit 1</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td>Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• BCUC IR 2.258.2</td></tr>
</table>

Description:

The purpose of this project is to improve the reliability of the Unit 1 generating equipment at the Ladore Generating Facility (**LDR**).

Key Drivers:

- Reliability

Issues Being Addressed:

Unit 1 at the Ladore facility has been in service since 1956. The equipment is mostly original, with the exception of the exciter which was replaced in 2002. There are increased reliability risks associated with the unit. The generator and turbine are in poor condition, increasing the likelihood of an extended forced without a significant intervention.

Discussion of Alternatives:

Five alternatives are being evaluated during Identification Phase:

i. **Do nothing:** run to failure;
ii. **Refurbish** following an evaluation of each asset, re-using as much of the existing equipment as possible;
iii. **Combined refurbish / replacement** by replacing the assets in Poor condition and refurbish those in Fair condition;
iv. **Replacement** of exciter, generator, governor, transformer and turbine except for embedded components. Refurbish embedded components; and
v. **New unit construction** in the Unit 3 bay.

Project Impacts and Benefits:

- Improve reliability at the Ladore Generating Facility

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when project reaches Implementation.

Additional Information:

There are four concurrent projects that may be impacted by this project:

i. GY-0234 LDR Install PH & Tailrace Crane must be, and is scheduled to be, completed to enable construction work for this project, as there is currently no powerhouse crane at LDR. This project is currently in Implementation Phase.
ii. GM-0044 LDR Upgrade Communication Systems should be implemented prior to, or simultaneously with this project. This project is currently in Identification Phase, Needs Stage.
iii. GM-0045 LDR Upgrade Protection & Control System is intricately linked with this project. As a result, a decision was made in Needs stage to merge GM-0045 into this project (G000741, GM-0043).
iv. LDR Redevelop Unit 2 does not yet have a project identifier, but is planned to follow redeveloping Unit 1. Consideration should be given to Unit 2 in design and procurement for Unit 1.

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: G003026	**Project Name:** Seton - Upgrade Unit	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Identification	**Filing Reference:** New	

Description:

The purpose of this project is to upgrade the unit equipment to ensure safe and reliable operation at the Seton Generating Station.

Key Drivers:

- Reliability
- Safety
- Environment
- Reputational

Issues Being Addressed:

The Seton Generating Station is operated almost continuously except for fisheries and maintenance requirements. Both the Seton generator and turbine are original equipment (1956) and are in Poor condition.

Due to the age and condition of the generator and turbine there is a risk that they could fail leading to loss of generation and an extended outage. This would result in high flows down Seton River and Lower Bridge River which could cause deviations to the Bridge/Seton system operating regime. We are engaging St'át'imc Nation and regulators as part of regularly scheduled meetings to discuss flows on these two rivers, and in the event of an unplanned outage we would notify all parties to discuss how to best manage the system. Also, if water needs to be diverted through Lower Bridge River, then this could result in an increased likelihood and magnitude of spills from Terzaghi Dam to Lower Bridge River beyond the Water Use Plan (**WUP Order**) targets for annual average flows and those same targets set forth in settlement agreements with the St'át'imc Nation. BC Hydro has been, and currently is, operating under a variance to our Water Use Plan order, approved by the Comptroller of Water rights (February 16, 2017).

Discussion of Alternatives:

Seven alternatives are being evaluated during Identification Phase:

i. **Do Nothing:** operate to failure;

ii. **Refurbish Unit With Unchanged Nameplate Rating.** It is expected that this approach could extend the unit life another 35 years;

iii. **Replace Unit With Unchanged Nameplate Rating.** It is expected that this approach would result in a new life of 40 to 50 years;

iv. **Refurbish Unit With Increased Nameplate Rating.** It is likely this approach would involve replacement of some elements of the unit and refurbishment of others, and could extend the unit life another 35 years;

v. **Replace Unit With Increased Nameplate Rating.** It is expected that this approach would result in a new life of 40 to 50 years;

vi. **Decommission Unit**, which would see Seton being used for water passage only. The dam, canal, and intakes would be retained. The unit mechanical and electrical components would be removed or reconfigured to provide the energy dissipation needed to discharge the water safely through the powerhouse to Fraser River; and

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">vii. Install Bypass Unit, which would involve installing a powerhouse bypass in a suitable location and of a suitable size to divert water from the main powerhouse during outages and/or in times of high inflows. This would allow the production of power from the bypassed water and also help to dissipate the stored energy before discharging to Fraser River.</td></tr>
<tr><td colspan="2">Project Impacts and Benefits:
• Improve the reliability of the Seton Generating Station;
• Provide reliable water conveyance capacity within the Bridge River system;
• Reduce the likelihood and magnitude of spills from Seton Lake Reservoir to Seton River and from Terzaghi Dam to Lower Bridge River, to minimize potential effects on fish, riparian habitat, and First Nations values;
• Maintain BC Hydro’s relationship with the St’at’imc Nation; and
• Reduce potential reputational impact due to high flow or spill events.</td></tr>
<tr><td>Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="2">Additional Information:
Other capital projects currently underway at Seton Generating Station include:
• G003268 GM-0075 Governor replacement (currently in Definition Phase)
• G000992 GY-0191 Protection and Control Upgrade (currently in Implementation Phase)
Some Generation P&C scope of work was not completed under Seton Upgrade Unit Protection & Control Project (GY0191) or the Seton Replace Governor Project (GM0075). This scope of work will be completed under this project.
The Bridge River System lies within the traditional territory of the St’át’imc Nation. BC Hydro and St’át’imc have a set of Agreements (signed in 2011) that settle all past, present and future claims related to the Bridge River facilities and provide legal certainty around continued operations of the Bridge River facilities and inform ongoing relationship development. BC Hydro is engaging the St’át’imc Nation in a manner consistent with our Agreements and continues to work with the St’át’imc to address issues and concerns around this project.</td></tr>
</table>

Investment Planning ID: **G000796**	**Project Name:** **Seven Mile Overhaul Units 1 to 3 Turbines**	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Identification	**Filing Reference:** F17-F19 RRA: • Appendix I, line 69, Appendix J, page 35 • BCUC IRs 1.70.3, 1.93.1-1.93.6, 2.249.8, 2.260.4, 2.262.1, • BCOAPO IR 1.36.1	

Description:

The purpose of this project is to improve the reliability of the Units 1 to 3 turbines that presently have seal erosion and runner blade cavitation issues at the at the Seven Mile Generating Station.

Key Drivers:

- Reliability
- Financial

Issues Being Addressed:

Seven Mile Units 1 to 3 have been in service for almost 40 years without a major turbine overhaul. The units are now demonstrating an elevated level of wear increasing the risk of turbine failure. The two main issues with the turbines are excessive runner crown and band seal erosion, and runner cavitation requiring cavitation repairs every two years.

The efficiency of the units has also been reduced over time. The Unit 1 to 3 turbines weighted average efficiency was measured in 1984 at 91.0 per cent. This was lower than the original guaranteed weighted average efficiency of 92.7 per cent. It is expected that turbine efficiency has been further reduced since then mainly because of changes in runner blade profile and runner seal erosion (seal clearance is larger than design).

Discussion of Alternatives:

Three alternatives were evaluated during Identification Phase:

i. **Do Nothing:** continue with cavitation weld repairs on turbine runners and routine inspections;

ii. **Turbine Refurbishment:** Refurbish and repair the runner and major components by sandblasting, welding, machining, repainting as applicable; and

iii. **Turbine Upgrade:** Re-design and replace the runner and wicket gates to eliminate cavitation, and achieve higher turbine efficiency and higher maximum capacity. Efficiency gains with a modern designed runner and wicket gates are expected to be in the range of 2.5 per cent to 3 per cent. This alternative would increase the total turbine capacity by 106.5 MW based on future turbine rated output of 213 MW (the existing rated turbine output 177.5 MW) x 3 units.

Alternative iii, Turbine Upgrade, was selected as the only viable alternative for the project. This alternative will adequately improve turbine performance and operating reliability, mitigate cavitation issues, and significantly increase useful life by more than another 50 years. Additionally, this alternative provides an opportunity to increase the efficiency, and possibly the operating range of the turbine runners, resulting in additional energy benefits.

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">Project Impacts and Benefits:
• Improve reliability by resolving the runner seal erosion and runner cavitation issues.
• Reduce operations and maintenance costs by resolving the runner seal erosion and runner cavitation issues.
• Reduce the risk of turbine failure.
• Increase turbine efficiency (by 2.5 per cent to 3 per cent) and operating range (by 106.5 MW).</td></tr>
<tr><td>Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="2">Additional Information:
As the planning level estimate for this project is over $100 million, BC Hydro expects that BCUC approval will be required for this project.
There are a number of capital projects at the Seven Mile Generating Facility scheduled for the next seven to 10 years. These include the intake gate project, Powerhouse (PH) crane synchronization, fire protection upgrade, governor controls upgrade, and cooling water. Some of the projects will need to be completed ahead of the turbine project (e.g., PH crane synchronization, intake gate refurbishment, and fire protection upgrade). Some of the projects are planned to be completed during the same outage as the turbine project and will require scope and boundary definition (e.g., governor controls upgrade and cooling water). The project team will coordinate with the requirements of these other projects.</td></tr>
</table>

<table>
<tr><td colspan="1">Investment Planning ID:
G001047</td><td colspan="2">Project Name:
Waneta Unit 3 Life Extension</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td>Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Identification (Teck Stage Gate 3)</td><td colspan="2">Filing Reference:
New</td></tr>
</table>

Description:

The purpose of this project is to reduce the risk of failure of Waneta Unit 3 hydroelectric generator.

Key Drivers:

- Reliability

Issues Being Addressed:

The primary issue being addressed is the condition of the stator winding and core. Inspections of Unit 3 stator have revealed a number risks:

- Lamination migration – the steel laminations which form the generator stator core have come loose and are moving. This can result in physical damage to the stator winding or contact with the rotor which can result in an electrical fault;
- Loose wedges – the wedges which hold the stator winding in place in the stator core have come loose. This can result in physical damage to the stator winding which can result in an electrical fault;
- Core buckling – the steel laminations which form the generator stator core have come loose and can buckle. This can lead to physical or thermal damage to the stator laminations and winding which can result in an electrical fault
- Loss of circularity – the generator stator core can lose its circularity which can result in hotspots or vibrations which can lead to further damage or an electrical fault.

In addition, Unit 3 suffers from a number of issues which will be considered during this project;

- Runner cavitation – the runner experiences frequent cavitation resulting in extensive welding repairs
- Runner cracking – extensive welding will lead to the build up of thermal stresses which, over time, can lead to cracking of the runner .
- Protection and Controls – the controls are original 1963 electromechanical relays and contain asbestos wiring; and
- Governor – original 1963 mechanical governor. Parts and maintenance support is limited.

Discussion of Alternatives:

Four alternatives were evaluated during Identification phase:

i. **Do nothing:** Replace the stator winding, stator core at failure;
ii. **Re-wedge** the stator winding;
iii. **Re-stack** the stator; and
iv. **Replace** the stator core and windings.

Alternative iv, replace the stator core and windings with a modern design, was chosen as the lead alternative as this is the only alternative that would address the root causes of the major defects reported with the stator.

In addition, the downtime required to address the stator yields the opportunity to replace other major components that are nearing end of life. These components include the runner, governor, protection and controls. Further risk assesments will be completed during Stage Gate 4 to confirm whether or not the following addional components need to be included as well:

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">

- Generator rotor;
- Power transformer;
- Wicket Gates; and
- Exciter.

</td></tr>
<tr><td colspan="2">

Project Impacts and Benefits:

- Improved reliability of the generator.
- Reduced operating and maintenance costs of the generator.

</td></tr>
<tr><td>

Project Implementation Phase Risk:

Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.

</td><td>

Risk Treatment:

To be determined when the project reaches Implementation.

</td></tr>
<tr><td colspan="2">

Additional Information:

On July 26, 2018, BC Hydro became the sole owner of Waneta. Teck Metals Ltd (**TML**) continues to act as the Operator of the facility during the 20-year lease term. In that role, Teck is required to operate, manage, and maintain Waneta in accordance with the terms of the Co-Possessors and Operating Agreement (**COPOA**), which includes capital planning and operating to a prudent owner standard, exercising the degree of care and skill of an experienced dam operator and acting in accordance with Good Utility Practice.

There are a number of projects that TML has agreed to complete as detailed in Schedule C of the COPOA, including this Unit 3 Life Extension project. As Operator at Waneta, TML will oversee the execution of the project and will provide regular updates to BC Hydro's Operating Committee representatives.

BC Hydro will retain an oversight role as part of the Waneta Operating Committee, including reviewing the annual operating plans for Waneta; however, as TML is the Operator of Waneta, processes that BC Hydro generally uses for internal asset management and planning purposes will not be applied.

</td></tr>
</table>

<table>
<tr><td>Investment Planning ID:
G003336</td><td colspan="2">Project Name:
G.M. Shrum - Intake Operating Gate Hydraulic Upgrade</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td>Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Future</td><td colspan="2">Filing Reference:
New</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to address reliability risks associated with operating the hydraulic systems used to raise and lower the 10 Intake Operating Gates (INOGs).
Refer to Appendix K – G.M. Shrum Facility Asset Plan for additional information.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The 10 GMS INOGs are opened and closed by hydraulic systems which consist of hydraulic cylinders, hydraulic power units (HPUs) and hydraulic lines. These are all original plant equipment from the 1970’s. Issues being addressed include: insufficient emergency close hoist capability, pitting corrosion of the hydraulic lines and lack of fail-safe and redundancy for the HPUs.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
Alternatives to be considered in the Identification Phase include:
i. Partial upgrade of targeted hydraulic components:
Upgrade the hydraulic hoisting systems to provide sufficient capacity for emergency closure of the operating gates and refurbish the hydraulic cylinders. This alternative would not address the issue of HPU redundancy; and
ii. Complete upgrade of hydraulic components:
A complete upgrade of the hydraulic hoisting system on Units 1 to 10 including the hydraulic cylinders, the hydraulic lines and individual HPUs for each unit.</td></tr>
<tr><td colspan="3">Project Impacts and Benefits:
• Improve reliability of the INOGs</td></tr>
<tr><td colspan="2">Project Implementation Phase Risk
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="3">Additional Information:
N/A</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: **G000130**	**Project Name:** **G.M. Shrum - U1 - U10 Water Passage Refurbishment**	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Future	**Filing Reference:** New	

Description:

The purpose of this project is to rehabilitate the 10 penstocks at G.M. Shrum.

Refer to Appendix K – G.M. Shrum Facility Asset Plan for additional information.

Key Drivers:

- Financial
- Safety
- Reliability

Issues Being Addressed:

A number of the penstocks have been assessed as Unsatisfactory and Poor based on the condition of the coating. Due to the compromised coatings, sections of the penstock steel liner, penstock exterior and scroll case show signs of deterioration and metal loss. Failure to address the active corrosion in a timely manner will result in loss of additional metal thickness and could lead to more expensive repairs or eventual penstock replacement.

Discussion of Alternatives:

The following alternatives will be explored in Identification:

i. **Replace** (strip and re-coat) the existing protective coating on all penstocks and key water passage components; and

ii. **Replace (strip and re-coat), refurbish (touch-up) or defer intervention** on a component by component basis. This would focus on high priority items in the short-term, and consider deferring lower priority items into the future.

Project Impacts and Benefits:

- Extend the life of the penstocks.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

N/A

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td>Investment Planning ID:
G000168</td><td colspan="2">Project Name:
Lake Buntzen 1 – Generator Replacement</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td>Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Future</td><td colspan="2">Filing Reference:
New</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to improve the reliability of the generator at the Lake Buntzen 1 facility.
Refer to Appendix K – Coquitlam-Buntzen System Facility Asset Plan for additional information.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Lake Buntzen 1 generator (60 MW) was assessed in 2016, and the Equipment Health Rating is Poor. The main issues leading to a Poor health rating include poor condition of the stator windings, stator core, and rotor windings, as confirmed by poor electrical test results, visible signs of deterioration and deformation, and a stator winding insulation failure which resulted in two coils cut-out in 2005.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
Three alternatives will be evaluated during Identification phase:
i. Do nothing;
ii. Refurbish the generator via rewinding; and
iii. Replace the generator.</td></tr>
<tr><td colspan="3">Project Impacts and Benefits:
• Address reliability risks associated with the Lake Buntzen generator.</td></tr>
<tr><td colspan="2">Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="3">Additional Information:
N/A</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: G000252	**Project Name:** Revelstoke - U1 - U4 Stator Replacement	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Future	**Filing Reference:** New	

Description: The purpose of this project is to address reliability risks associated with the Units 1 to 4 generator stator cores, stator windings and frames. Refer to Appendix K – Revelstoke Facility Asset Plan for additional information.
Key Drivers: • Reliability
Issues Being Addressed: The Unit 2 to 4 generators are in Poor condition. The main issues leading to a Poor Equipment Health Rating include poor condition of the stator windings, stator core, and rotor windings, as confirmed by poor electrical test results and visible signs of deterioration and deformation. The generator stator issues have been managed with interventions, operating restrictions and monitoring since 2007. Unit 1 is currently rated as being in Fair condition; however, considering the long lead time associated with this project and the fact that all units are the same age and design, intervention on Unit 1 will be considered within the project alternatives.
Discussion of Alternatives: Planning stage alternatives that have been identified include: i. **Replace** stator components for Units 1 to 4 ii. **Replace, Refurbish or defer** intervention on a unit-by-unit basis. Refurbishment would re-wind, as opposed to replace, the stator core
Project Impacts and Benefits: • Address reliability risks associated with Units 1 to 4 generators at Revelstoke

Project Implementation Phase Risk	**Risk Treatment**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information: N/A

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td>Investment Planning ID:
92525</td><td colspan="2">Project Name:
Fort St John and Taylor Electric Supply</td></tr>
<tr><td>Forecast Capital Cost:
$53.1 million</td><td>Forecast In-Service Date:
Fiscal 2021</td><td>Start Date of Construction:[1]
Fiscal 2016</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• Appendix I, line 7, Appendix J, page 43
• BCUC IRs 1.70.3, 1.81.14, 1.99.1 – 1.99.5, 2.249.8, 2.260.4, BCOAPO 1.36.1</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to remove a portion of the 138kV lines that currently supply the communities of Taylor and Fort St. John to accommodate construction of the Site C 500 kV transmission lines. To continue to supply Taylor and Fort St. John, this project will construct a new 138kV switchyard, including two 500/138 kV transformers, within the future Site C 500 kV substation. The project will also construct six kilometres of new 138 kV transmission line to supply Taylor and Fort St John from the new Site C substation.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
Two 138 kV transmission lines currently occupy the transmission right-of-way reserved for the Site C 500 kV transmission lines and supply the communities of Taylor and Fort St. John from G.M. Shrum Generating Station (GMS). There is insufficient right-of-way available to retain the existing 138 kV lines and construct the new 500 kV lines.
Removal of the 138 kV lines to accommodate construction of the Site C 500 kV transmission lines will result in a 250 MW load supply shortfall in the Fort St. John-Taylor area, therefore the lines are being re-terminated at the new Site C Substation.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
Partially remove the 138 kV lines to enable construction of the new Site C 500 kV transmission lines and re-connect the 138 kV lines to an expanded Site C Substation. This was selected as the preferred alternative as it avoids a load supply shortfall to the Fort St John – Taylor area.</td></tr>
<tr><td colspan="3">Project Impacts and Benefits:
• Line losses will be reduced by removing the 138 kV lines and serving Fort St John and Taylor from an expanded Site C substation which is closer to the load centre.
• Operating and maintenance cost savings.
• Transmission reliability to Fort St John and Taylor will be improved by feeding these communities from a 500 kV substation.
• Future transmission system capacity will be enabled in the North Peace Region by providing capability in the Site C substation to connect additional 500 kV, 230 kV and 138 kV transmission lines.</td></tr>
<tr><td colspan="2">Project Implementation Phase Risk:
This project currently does not have any identified Zone 3 (high) Implementation Phase risks.</td><td>Risk Treatment: N/A</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Additional Information:
N/A

Investment Planning ID: 900219	**Project Name:** DVES: West End Substation - Property Purchase	
Forecast Capital Cost: $80.7 million	**Forecast In-Service Date:**[1] Fiscal 2021	**Start Date of Construction:**[2] Fiscal 2019
Development Phase: Implementation	**Filing Reference:** [redacted]	

Description:

The purpose of this project is to acquire property rights to allow construction of a new substation in the West End of downtown Vancouver to replace the existing Dal Grauer substation.

Refer to Appendix K – Downtown Vancouver Electric Supply Plan for additional information.

Key Drivers:

- Reliability

Issues Being Addressed:

Vancouver's downtown peninsula is currently supplied by three substations; Murrin (**MUR**), Dal Grauer (**DGR**), and Cathedral Square (**CSQ**). All three are approaching their firm capacity, with DGR and MUR approaching end-of-life as they date to 1953 and 1947, respectively. DGR is too physically constrained to allow for expansion or redevelopment while serving load, with no practical means of transferring the load to nearby stations. In addition, DGR is radially supplied by four 69 kV underground circuits fed by two 230/69 kV transformers located at MUR. These circuits and transformers are vulnerable to severe earthquake damage. For these reasons, a replacement station for DGR in a new location is required.

This project secures the property rights to allow the replacement of DGR (195 MVA capacity) with a new substation in the West End (ultimate 400 MVA capacity).

The scope of this project is to acquire property rights to site the new West End Substation, including required transmission and distribution rights-of-ways. Underground property rights for the substation were acquired in August 2018 from the Vancouver School Board at the location presently occupied by the existing Lord Roberts Annex school at 1150 Nelson Street. The acquisition of the remaining required property rights, including distribution and transmission statutory rights-of-way through Nelson Park, is ongoing and is expected to be complete by early fiscal 2021.

A separate project to design and construct the new substation will be initiated later in fiscal 2019 now that the location and attributes of the acquired property are defined.

Discussion of Alternatives:

Eleven potential downtown sites were investigated for the new West End Substation. These were shortlisted to four sites, and eventually BC Hydro made conditional offers on two sites: an underground parcel sited by the existing Lord Roberts Annex, and a private property several blocks to the west. The private property was more expensive than the forecasted property rights at the Lord Roberts Annex, but allowed for the construction of a less expensive above-ground indoor substation when compared to an underground station required at Lord Roberts Annex. With the additional transmission and distribution connectivity costs for the private property factored in, the overall cost of the new West End Substation including all required property rights was estimated to be similar at both sites.

BC Hydro determined that the parcel at Lord Roberts Annex was the preferred alternative given all the benefits that this alternative will provide to the Vancouver School Board and the residents of downtown Vancouver. The avoidance of uncertainty and delay in the acquisition of property rights, and the fact that

[1] Forecast In-Service Date refers to date when required rights of way through Nelson Park are secured.
[2] Start Date of Construction refers to the approval date to acquire the property.

<table>
<tr><td colspan="2">Lord Roberts Annex is closer to DGR which will result in a more efficient transfer of load and de-energization of DGR, were also significant advantages.
The property rights secured at Lord Roberts Annex include an underground parcel on a fee-simple basis which avoids the future expenditure and risk of a long-term leasehold arrangement.</td></tr>
<tr><td colspan="2">Project Impacts and Benefits:
The project will allow the replacement of DGR, and thereby improve security of supply to the downtown peninsula.</td></tr>
<tr><td>Project Implementation Phase Risk:
Rights-of-way on an adjacent property must still be secured - the timing and cost may vary from current expectations.</td><td>Risk Treatment:
Negotiate with property owner, after the stakeholder consultation process, to find a suitable compromise for all parties.</td></tr>
<tr><td colspan="2">Additional Information:
This project will be followed by a project developed under Planning ID 900598 to design and build a substation on this site.</td></tr>
</table>

Investment Planning ID: **92216**	**Project Name:** **Peace Region Electric Supply (PRES)**	
Forecast Capital Cost: $348 million to $197 million	**Forecast In-Service Date:** Fiscal 2022	**Start Date of Construction:**[1] Fiscal 2019
Development Phase: Definition	**Filing Reference:** Amended F12-F14 RRA: • Application: Amended Appendix I, page 17; Amended Appendix J, page 99 • BCUC IRs 1.204.1 Attachment 1, 1.250 series • AMPC IR 1.46.1 • ESVI IRs 1.4 series Dawson Creek/Chetwynd Area Transmission CPCN Application: • BCUC Order Nos. G-144-12 and C-5-13 F2014 Annual Report to the BCUC: • Appendix I, line 48; • Appendix J, page 65. F17-F19 RRA: • Appendix I, line 10, Appendix J, page 47 • BCUC IRs 1.70.3, 1.102.1 – 1.102.8, 2.249.8, 2.260.4, BCOAPO IR 1.36.1, AMPC IRs 1.17.1 to 1.17.6	

Description:

The purpose of this project is to construct two 58 km long 230 kV transmission lines between South Bank substation and Shell Groundbirch substation in the Peace Region. The project also involves constructing a new 230 kV switchyard at South Bank substation including transformation and expanding Shell Groundbirch substation to terminate the new transmission lines in the station.

Key Drivers:

- Reliability
- Reputational

Issues Being Addressed:

The Peace Region is supplied by a network of 138 kV and 230 kV transmission lines originating at the G.M. Shrum Generating Station. According to the May 2016 South Peace Load Forecast – December 2017 update, the load growth in the Peace Region (particularly in the Dawson Creek and Groundbirch areas) is expected to increase by 500 MW by 2028 such that the ability of the transmission system to maintain supply to all customers during system events will be exceeded. In addition to this, based on customer commitments, the ability of the system to supply the growing load under normal conditions is expected to be exceeded by fall 2021. At this point, no further load can be connected in the area without system reinforcement.

In August 2017, the provincial government's Mandate Letter also identified "advancing government's climate action strategies including through fuel switching and electrification initiatives in the transportation, oil and gas, and other sectors" as a key responsibility for BC Hydro. This mandate places an expectation that BC Hydro is in a position to meet the electrification needs of customers in the Peace Region.

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1 Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives:	
The following seven alternatives were assessed in the Identification Phase: i. **Do nothing**; ii. **Construct a new transmission line** from G.M. Shrum Generating Station to Sundance Substation via Sukunka Substation; iii. **Construct a new transmission line** from G.M. Shrum Generating Station to Sundance Substation via Dokie Terminal Substation; iv. **Construct a new transmission line from New Dokie Ridge Substation to Sundance Substation**; v. **Construct a new transmission line from New Pine Valley Substation to Sundance Substation**; vi. **Construct a new transmission line from the Planned South Bank Substation (A 230 kV Switchyard At The Site C Substation) to Shell Groundbirch Substation**;and vii. **Non-wire alternatives:** Non-wire alternatives, such as demand side management and temporary generation were considered for short term needs. Alternative vi, Construct a new transmission line from the planned South Bank Substation, was selected as the preferred alternative because it is the most cost effective solution that addresses the project needs.	
Project Impacts and Benefits:	
• Provide reliable service (N-1) to new and existing customers at the earliest possible in-service date. • Enable electrification of the upstream natural gas industry in the Peace region providing an opportunity to reduce provincial greenhouse gas emissions.	
Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.
Additional Information:	
Order In Council (**OIC**) 101 adds as prescribed undertakings for the purpose of section 18 of the Clean Energy Act investments in infrastructure in Northeast British Columbia that primarily serve natural gas producers and processors (section 4(2) of the Greenhouse Gas Reduction (Clean Energy) Regulation). This includes the Peace Region Electricity Supply (PRES) Project and accordingly, BC Hydro will not be filing an application under section 45(5) of the *Utilities Commission Act* for a Certificate of Public Convenience and Necessity for the PRES Project.	

<table>
<tr><td>Investment Planning ID:
93845</td><td colspan="2">Project Name:
Metro North Transmission (MNT)</td></tr>
<tr><td>Forecast Capital Cost:
$530 million to $300 million</td><td>Forecast In-Service Date:
Fiscal 2025</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Definition</td><td colspan="2">Filing Reference:
Fiscal 2014 Annual Report:
• Appendix I, line 22;
• Appendix J, page 60.
F17-F19 RRA:
• Appendix I, line 8, Appendix J, page 44,
• BCUC IRs 1.70.3, 1.97.7, 1.100.1 – 1.100.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to construct a new 230 kV transmission line between Coquitlam and Vancouver via Port Moody, Anmore and Burnaby, including a new transmission line crossing of Burrard Inlet.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
As a result of load growth in the Metro Vancouver region (which includes Vancouver, Burnaby, New Westminster, Richmond, and the Coquitlam/Tri Cities), a shortfall of supply capacity is anticipated within the next five years in the Metro North 230 kV Transmission System. The constraints on the 230 kV transmission system could result in curtailment of up to 100 MW of load in the Metro Vancouver region (an amount equal to approximately 15 per cent of Downtown Vancouver) to avoid overloading and potentially damaging transmission equipment. An interim operational solution has been identified to temporarily resolve these constraints by reconfiguring the system with real-time switching operation, such that no load curtailment will be required until fiscal 2025, after which time this project is expected to resolve the constraints.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
The following four alternatives were assessed during Identification phase:
i. Do Nothing;
ii. Construct a New Overhead 230 kV Transmission Line from Como Lake Substation to Horne Payne Substation through South Coquitlam/Central Burnaby and install a new underground Transmission Line from Horne Payne Substation to Mount Pleasant Substation;
iii. Construct a new 230 kV Transmission Line with overhead and underground sections from Meridian Substation to Horne Payne Substation via Port Moody/Anmore/ Burnaby and a new crossing of Burrard Inlet, and install a new underground transmission line between Horne Payne Substation and Mount Pleasant Substation; and
iv. Construct a new 230 kV underground transmission line from Como Lake to Mount Pleasant through central Coquitlam, Burnaby and Vancouver.
Alternative iii. Construct a new 230 kV transmission line with overhead and underground sections from Meridian Substation via Horne Payne Substation to Mount Pleasant Substation was selected as the preferred alternative because it is the most cost effective solution that addresses the issues.</td></tr>
</table>

1 Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">Project Impacts and Benefits:
• Increase the supply capability of the Metro North transmission system and provide reliable service to new and existing customers in the Metro Vancouver region.</td></tr>
<tr><td>Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="2">Additional Information:
N/A</td></tr>
</table>

Investment Planning ID: 92423	**Project Name:** Bridge River Transmission Project	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Identification	**Filing Reference:** New	

Description:

The purpose of this project is to reinforce the transmission system to ensure generation can be delivered at all times of the year from the Bridge River Area to South Interior West via 2L90, without requiring curtailment of Bridge River 1 and 2 Generation.

Key Drivers:

- Reliability
- Environment
- Financial Loss
- Reputational

Issues Being Addressed:

The capacity of the Bridge River transmission system is insufficient to accommodate the Bridge River generation at all times of the year. Currently, when the ambient temperature in the area and regional generation are high, 2L90 may overload. The current mitigation for the 2L90 overload is to curtail the output of Bridge River 1 and 2 Generation, which may increase the likelihood and magnitude of spills from Terzaghi Dam to the Lower Bridge River beyond the Water Use Plan Order (**WUP Order**) targets for annual average flows. BC Hydro has been, and currently is, operating under a variance to our Water Use Plan order, approved by the Comptroller of Water rights (February 16, 2017). With the reduction in generating capacity and the loss of storage due to the drawdown of the Downton Reservoir, effective water management in the system is hindered, and is therefore an important driver for reducing the need to curtail Bridge River generation.

Discussion of Alternatives:

Three alternatives will be evaluated during Identification Phase:

i. **Do nothing:** continue to restrict Bridge River generation in order to prevent overload on 2L90;

ii. **Restore thermal rating** of 2L90 to 55°C operation and upgrade it to 90°C operation to provide sufficient capacity; and

iii. **Upgrade Rosedale (ROS) substation** to add a 360/230 kV transformer.

Project Impacts and Benefits:

- Increase transmission capacity in the Bridge River area to meet the higher generation demands of the system.
- Reduce financial losses associated with generation curtailment.
- Provide reliable water conveyance capacity within the Bridge River system.
- Reduce the likelihood and magnitude of spills from Terzaghi Dam to Lower Bridge River, in order to minimize potential effects on fish, riparian habitat, and First Nations values.
- Maintain BC Hydro’s relationship with the St’at’imc Nation.
- Reduce potential reputational impact due to spill events.

[1] Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: This project will be timed in order to meet the higher generation demands associated with another project, Bridge River 1 Replace Units 1 to 4 Generators / Governors (G000776). The Bridge River System lies within the traditional territory of the St'át'imc Nation. BC Hydro and St'át'imc have a set of Agreements (signed in 2011) that settle all past, present and future claims related to the Bridge River facilities and provide legal certainty around continued operations of the Bridge River facilities and inform ongoing relationship development. BC Hydro is engaging the St'át'imc Nation in a manner consistent with our Agreements and continues to work with the St'át'imc to address issues and concerns around this project.	

<table>
<tr><td colspan="1">Investment Planning ID:
94034 and 94032</td><td colspan="2">Project Name:
West Kelowna Transmission and Westbank Substation Upgrade Projects</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td>Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• Appendix I, lines 9 and 35, Appendix J page 46 and page 62
• BCUC IRs 1.70.3, 1.101.1-1.101.6, 2.249.8, 2.249.14, 2.260.4
• BCOAPO IRs 1.36.1, 2.77.1, 2.83.1
• CECBC IR 1.72.3.2,</td></tr>
<tr><td colspan="3">Description:
West Kelowna Transmission Project:
The purpose of the West Kelowna Transmission Project is to build a new secondary 138 kV transmission line to strengthen the transmission network delivering electricity to the City of West Kelowna and the District of Peachland.
Westbank Substation Upgrade Project:
The purpose of the Westbank Substation Upgrade Project is to increase station firm capacity and replace end of life assets on an expanded footprint.</td></tr>
<tr><td colspan="3">Key Drivers:
West Kelowna Transmission Project:
• Reliability
Westbank Substation Upgrade Project:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
West Kelowna Transmission Project
Since 1994 there have been three sustained forced outages; one in 1994 caused by lightning resulting in a six-hour outage; one in October 2007 caused by lightning resulting in a seven-hour outage; and the October 2014 pole-top fire related outage resulting in a nine-hour outage. The single outage in 2014 resulted in significant customer hours lost (CHL) (180,000) for West Kelowna. The CHL consequence due to an outage in the area is significant and indicated that BC Hydro should address this risk. Other factors that contribute to the challenge of restoring power include the length of the existing transmission line, its location in rugged and remote terrain, and it’s susceptibility to forest fires and landslides.
While the existing line is considered to be reliable, adding a new, second transmission line (or cable) will provide redundancy to the system, ensuring continued, reliable power in the event of an outage on the existing line.
Westbank Substation Upgrade Project
The peak summer load at Westbank Substation (WBK) exceeds the firm summer capacity of the station. Several components of the substation are also reaching end of life. This includes one 138 kV oil circuit breaker and one 25 kV oil circuit breaker, two circuit switchers and one voltage transformer.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives:

West Kelowna Transmission Project

Three alternatives were evaluated during Identification Phase for the West Kelowna Transmission Project:

i. **Build a new transmission line to Vernon Terminal Substation** on the west side of Okanagan Lake, connecting Westbank Substation to Vernon Terminal Substation;

ii. **Build a new transmission line to Nicola Substation** connecting Westbank Substation to Nicola Substation using primarily a different route than the existing line; and

iii. **Build a new transmission line to FortisBC** including a submarine cable across Okanagan Lake, connecting Westbank Substation to the FortisBC system.

Alternative ii, Build a new transmission line to Nicola Substation connecting Westbank Substation to Nicola Substation, was selected as the leading alternative as it is more favorable from an overall safety, environmental, socio-economic, cost, geotechnical and wildfire risk perspective compared to the other alternatives.

Westbank Substation Upgrade Project

Three alternatives were evaluated during Identification Phase for the Westbank Substation Upgrade Project:

i. **Upgrade Westbank Substation** to increase firm transformation capacity, replace end of life assets and add space provision to interconnect the new transmission line;

ii. **Build a new substation** to accommodate load growth in the West Kelowna area,; and

iii. **Do nothing:** continue as usual, with curtailment of customer load during transformer contingency.

Alternative i, Upgrade Westbank Substation, is the only viable alternative for the project.

Project Impacts and Benefits:

West Kelowna Transmission Project:

- Improve reliability in West Kelowna by providing redundancy to the system.

Westbank Substation Upgrade Project:

- Increase firm transformation capacity to meet demand.
- Replace end of life assets on an expanded footprint.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

In the BCUC's Decision on our Previous Application, BC Hydro was directed to file a Certificate of Public Convenience and Necessity application for both the West Kelowna Transmission Project and Westbank Substation Upgrade Project. The BCUC also found these two projects to be sufficiently linked that they could be expediently reviewed in one process. The decision provides some flexibility for BC Hydro to have the two projects reviewed in a single process or separately if necessary.

Investment Planning ID: 900266	**Project Name:** East Vancouver - Substation Construction	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Future	**Filing Reference:** New	

Description:

This project will build a new 230/12 kV to 25 kV, 400 MVA (ultimate capacity), station in the Eastside/Strathcona neighbourhood of Downtown Vancouver as part of the second stage of the 30-year Downtown Vancouver Electricity Supply Plan.

Refer to Appendix K – Downtown Vancouver Electric Supply Plan for additional information.

Key Drivers:

- Reliability

Issues Being Addressed:

The Downtown Vancouver area is comprised of the Downtown, West End, Strathcona, and Grandview-Woodland neighbourhoods. The area is supplied by a 230 kV and 69 kV transmission network and three substations:

- Cathedral Square substation (built in 1984);
- Dal Grauer substation (built in 1953); and
- Murrin substation (built in 1947).

There are a number of risks and issues at the ageing Dal Grauer and Murrin substations. More than half of the assets are expected to degrade to poor or very poor condition in the next 10 to 20 years, presenting a reliability risk. Murrin substation is on seismically unstable soil. Approximately half of the 230 kV switchyard, which supplies both Murrin and Dal Grauer loads, is vulnerable to severe earthquake damage from liquefaction and settlement. Physical space constraints at Dal Grauer make redevelopment of the substation in its current location not possible while serving load.

The long term strategy for the area is to mitigate the above reliability and safety risks by replacing Murrin and Dal Grauer substations with new substations. One of these is the new ‘East End Substation’.

Discussion of Alternatives:

The ultimate capacity of the East End substation will be 400 MVA, located in the Strathcona neighbourhood of Vancouver. The project will consider different options for the size of the substation when it is first constructed, given that the 400 MVA capacity may not be required immediately.

Project Impacts and Benefits:

- Improve Eastside/Strathcona Vancouver area reliability.
- Minimize worker safety risks in the area.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when this project reaches Implementation.

Additional Information:

See also Appendix J for the related project:

- Investment Planning ID: 900598; and
- Project Name: West End - Substation Construction and System Reinforcement.

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td>Investment Planning ID:
900598</td><td colspan="2">Project Name:
West End - Substation Construction and System Reinforcement</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td>Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Future</td><td colspan="2">Filing Reference:
Amended F12-F14 RRA:
• Application: pages 6-17, 6-24, 6-63, 6-64
• BCUC IRs 1.181.1 Attachment 1, 1.265.1, 2.101.2, 2.102.1, 2.123.1 Attachment 1
• BCOAPO IR 1.38.1 Attachment 2
• CEC IR 1.25.1 Attachment 1
F2014 Annual Report to the BCUC:
• Appendix I, line 20;
• Appendix J, page 46.
F17-F19 RRA:
• Appendix I, line 14, Appendix J, page 51
• BCUC IRs 1.70.3, 1.104.1-1.104.3, 2.249.8, 2.253.2, 2.260.4, BCOAPO IR 1.36.1</td></tr>
<tr><td colspan="3">Description:
This project will build a new 230/12 kV to 25 kV, 400 MVA (ultimate capacity), underground substation in the West End neighbourhood of Downtown Vancouver as part of the first stage of the 30-year Downtown Vancouver Electricity Supply Plan.
Refer to Appendix K – Downtown Vancouver Electric Supply Plan for additional information.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Downtown Vancouver area is comprised of the Downtown, West End, Strathcona, and Grandview-Woodland neighborhoods. The area is supplied by a 230 kV and 69 kV transmission network and three substations:
• Cathedral Square substation (built in 1984);
• Dal Grauer substation (built in 1953); and
• Murrin substation (built in 1947).
There are a number of risks and issues at the ageing Dal Grauer and Murrin substations. More than half of the assets are expected to degrade to poor or very poor condition in the next 10 to 20 years, presenting a reliability risk. Murrin substation is on seismically unstable soil. Approximately half of the 230 kV switchyard, which supplies both Murrin and Dal Grauer loads, is vulnerable to severe earthquake damage from liquefaction and settlement. Physical space constraints at Dal Grauer make redevelopment of the substation in its current location a challenge.
The long-term strategy for the area is to mitigate the above reliability and safety risks by replacing Murrin and Dal Grauer substations with new substations. The first of these is the new ‘West End Substation’.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives: The ultimate capacity of the underground substation will be 400 MVA, located in the West End neighborhood of Downtown Vancouver. The project will consider different options for the size of the substation when it is first constructed, given that the 400 MVA capacity may not be required immediately.	
Project Impacts and Benefits: • Improve West End Vancouver area reliability. • Minimize worker safety risks in the area.	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: See also Appendix Js for the related projects: • Investment Planning ID: 900266; Project Name: East Vancouver - Substation Construction; and • Investment Planning ID: 900219; Project Name: DVES: West End Substation – Property Purchase.	

Investment Planning ID: 90957	**Project Name:** Peace to Kelly Lake Capacitors	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Identification	**Filing Reference:** New	

Description:

The purpose of the project is to reinforce the transmission system between the Peace Region and Kelly Lake substation to ensure transfer capacity is in place for new generation in the Peace Region.

Key Drivers:

- Reliability.

Issues Being Addressed:

The Peace Region is a major generation source for BC Hydro, generating enough power to meet about 36 per cent of the total energy demand in the province. BC Hydro's Network Integration Transmission Services (**NITS**) Base Resource Plan (**BRP**) Rev 06 released on November 25, 2016 identifies a large amount of hydro generation and other intermittent generation being added by 2024 and through until 2034. The Peace Region to Kelly Lake 500 kV transmission system carries power generated in the Peace Region to load centers in the south of the province. The existing transfer demand on the Peace to Kelly Lake transmission section is near 95 per cent of the transfer capacity of the lines. The addition of Site C and other generation in the Peace Region will cause the required power transfer to exceed the available transmission capacity. System studies show that the transfer capacity of the Peace Region to Kelly Lake 500 kV transmission system is limited by thermal, voltage and transient stability and will require significant reinforcements starting in 2024 to deliver the power from the Peace Region to the south of the province without constraints.

Discussion of Alternatives:

Three alternatives were evaluated during Identification Phase:

i. **65 Per Cent Series Compensation via four new capacitor stations** and decommissioning of Kennedy (**KDY**) and McLeese (**MLS**) capacitor stations;

ii. **65 Per Cent Series Compensation via two new capacitor stations** and addition of series compensation at Williston (**WSN**), and decommissioning of KDY capacitor station; and

iii. **65 Per cent Series Compensation via three new capacitor stations** and decommissioning of KDY capacitor station.

Alternative iii, 65 per cent Series Compensation via three new capacitor stations and decommissioning of KDY capacitor station, was selected as the leading alternative as it meets the project objectives, avoids current restrictions between WSN and KLY, and allows some flexibility to respond to changes in load or planning requirements during project development.

Project Impacts and Benefits:

- Improve reliability through reinforcement of the transmission corridor between the Peace Region and Kelly Lake substation so power from new generation in the Peace Region can be moved south.
- Building capacitor stations will help maintain the voltage levels of the transmission lines, maximizing the amount of electricity the existing lines can move.

[1] Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk	**Risk Treatment**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.
Additional Information: The project will require upgrades to the WSN substation, and will need to coordinate outages with any other planned outages. As the planning level estimate for this project is over $100 million, BC Hydro expects that BCUC approval will be required for this project.	

Investment Planning ID: 900992	**Project Name:** Lower Mainland - Capacitive and Reactive Power Reinforcement	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Future	**Filing Reference:** New	

Description:

Implement sufficient reactive power compensation in the Lower Mainland transmission system to provide voltage support and control to the Lower Mainland transmission system, and to address the Fraser Valley voltage stability constraints.

Refer to Appendix K – Burrard Synchronous Condensers Replacement Study for additional information.

Key Drivers:

- Reliability

Issues Being Addressed:

This project will address the following two issues:

- **Issue 1:** The four Burrard Synchronous Condenser units are reaching end-of-life and are expected to experience reliability issues within the short to medium term. Each unit is rated as -50 MVAr / +100 MVAr. The four units provide capacitive and reactive power to the Lower Mainland transmission system, which allows voltage control and prevents voltage instability during peak load periods.
- **Issue 2:** The 2016 NERC Transmission Planning assessment of the Fraser Valley transmission system identified voltage stability constraints caused by additional reactive power losses within the 10-year planning horizon. The voltage instability would result in voltage collapse and subsequent load loss in the Fraser Valley.

Discussion of Alternatives:

The alternatives being considered include:

i. **Install 230 kV Shunt Capacitor and Shunt Reactor Compensation:** A total of 750 MVAr of capacitive power compensation and a total of 200 MVAr of shunt reactive power compensation would be installed in the Lower Mainland at 230 kV;

ii. **Install 500 kV and 230 kV Shunt Capacitor and Shunt Reactor Compensation:** A total of 750 MVAr of capacitive power compensation would be installed in the Lower Mainland: 250 MVAr at 500 kV, and 500 MVAr at 230 kV. A total of 200 MVAr shunt reactive power compensation would be installed in the Lower Mainland at 230 kV; and

iii. **Restore Burrard Synchronous Condenser Capability and Install Shunt Capacitor Compensation:** Burrard Synchronous Condenser reactive power function would be restored and 500 MVAr of capacitive power compensation would be installed in the Fraser Valley at 230 kV.

Project Impacts and Benefits:

- Maintain BC Hydro’s Lower Mainland bulk transmission system reliability during heavy winter load periods under single contingency conditions.
- Reduce the likelihood of cascading outages to the rest of the WECC system.
- Secure regional Fraser Valley transmission system reliability by compensating for VAr losses during heavy winter load periods under single contingency conditions.

[1] Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: N/A	

Investment Planning ID: **901251**	**Project Name:** **Interior to Lower Mainland - Remedial Action Schemes Installation**	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Future	**Filing Reference:** New	

Description:

This project is to implement a load shedding remedial action scheme (**RAS**) to shed loads at various BC Hydro distribution substations and transmission customer substations in the Lower Mainland and Vancouver Island for certain 500 kV single contingency events during winter heavy load conditions starting as early as 2023. BC Hydro is in the process of developing a new load forecast that will impact the timing for this project.

Key Drivers:

- Reliability

Issues Being Addressed:

Voltage stability constraints would affect the supply reliability of the Interior to Lower Mainland (**ILM**) 500 kV transmission system under certain single contingency events during winter peak load period starting as early as 2023. This timing will be impacted by BC Hydro's new load forecast that is being developed. This is an interim solution and BC Hydro will develop a long-term solution that will be informed by the next IRP.

Discussion of Alternatives:

Alternatives identified for this project include:

i. **Implement a load shedding RAS** to shed loads at various BC Hydro distribution substations and transmission customer substations in the Lower Mainland and Vancouver Island for certain 500 kV single contingency conditions during winter peak load conditions;

ii. **Investigate additional capacity** focused DSM in the Lower Mainland in addition to the current energy focused DSM as an interim solution; and

iii. Do Nothing: This is not considered as BC Hydro will not be able to maintain the system stability in the ILM transmission system during peak load periods under contingency conditions**.**

Project Impacts and Benefits:

- Maintain BC Hydro bulk transmission system reliability.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

N/A

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: **93788**	**Project Name:** **Capilano Substation Upgrade**	
Forecast Capital Cost: $88.0 million to $50.0 million	**Forecast In-Service Date:** Fiscal 2025	**Start Date of Construction:**[1] Fiscal 2020
Development Phase: Definition	**Filing Reference:** Amended F12-F14 RRA: • Application: Amended Appendix I, page 18; • Amended Appendix J, page 125 • BCUC IR 1.204.1 Attachment 1 F2014 Annual Report: • Appendix I, line 113; • Appendix J, page 41. F17-F19 RRA: • Appendix I, line 36, Appendix J, page 63 • BCUC IRs 1.70.3, 2.249.8, 2.253.2, 2.260.4, BCOAPO IR 1.36.1	

Description:

The purpose of this project is to improve the reliability and reduce the safety risks at Capilano Substation (**CAP**).

Key Drivers:

- Reliability
- Safety

Issues Being Addressed:

The CAP substation is over 60 years old and most of its major equipment is near end of life and needs immediate replacement. In particular, the 60 kV bulk-oil and 12 kV air-blast circuit breakers are obsolete and pose worker safety and reliability risks. The Asset Health Index on key equipment in the station such as the Protection and Control System, Instrument Transformers and Disconnect Switches is rated as Poor or Very Poor. In addition, the existing feeder section buildings do not meet current seismic standards and the equipment inside one of the buildings does not meet required safe electrical working clearances.

The new CAP substation will provide 25 kV distribution voltage. The existing 12 kV substation will be decommissioned after the surrounding service area has been converted to 25 kV operation which is planned to align with the construction of the new substation.

Discussion of Alternatives:

During Identification Phase the following alternatives were assessed:

i. **Do Nothing**;
ii. **Upgrade** existing CAP substation;
iii. **Replace** CAP substation on new property; and
iv. **Defer** project beyond fiscal 2022.

Alternative ii, Upgrade existing CAP substation, was selected as the preferred alternative as it meets the project objectives and has fewer issues than the replacement alternative.

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">Project Impacts and Benefits:
• Improve reliability for the North Vancouver area through addressing aging equipment concerns.
• Reduce worker safety risks caused by electrical working clearances and seismic issues.</td></tr>
<tr><td>Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase..</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="2">Additional Information:
N/A</td></tr>
</table>

<table>
<tr><td>Investment Planning ID:
92907</td><td colspan="2">Project Name:
Mount Lehman Substation Upgrade</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td>Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
F2014 Annual Report to the BCUC:
• Appendix I, line 116;
• Appendix J, page 61.
F17-F19 RRA:
• Appendix I, line 33, Appendix J, page 61,
• BCUC IRs 1.70.3, 2.249.8, 2.254.1.1, 2.260.4, BCOAPO IR 1.36.1</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to upgrade the Mount Lehman (MLE) substation to enable decommissioning of the Sumas Way (SMW) substation and serve load in the Abbotsford area.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Safety</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Abbotsford area is currently supplied by the Clayburn (CBN), Gloucester (GLT), MLE and SMW substations. At present, the total capacity of these four stations is 360 MVA. MLE is a 230/25 kV substation and was placed in service in 2007, with a total transformation capacity of 100 MVA.
Expansion of the MLE substation is required to enable decommissioning of the SMW substation. SMW has increased reliability risks due to degrading asset condition and has elevated safety risks due to the non-arc resistant metalclad design of the 25 kV feeder section. The expansion of MLE substation will also enable safety improvements to be undertaken at CBN substation and ensure that load in the Abbotsford area continues to be served over time.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
This project was identified as a result of a 30-year study carried out for the Abbotsford area in 2013 to mitigate safety issues at SMW and CBN substations and address capacity shortage in the Abbotsford area. The area study resulted in three alternative solutions being identified and reviewed. The alternative comparison was a comparison of different implementation strategies to determine not only what should be done, but also timing. Alternatives were re-evaluated during the Identification Phase of this project. A leading alternative was accepted that includes three phases of upgrades and four major projects:
First Phase:
i. MLE Substation Expansion to 170 MVA (ultimate 200 MVA) (this project);
Second Phase:
ii. CBN Substation reinforce to 200 MVA (Investment Planning ID: 92910);
iii. SMW Substation Decommissioning (Project release after fiscal 2023); and
Third Phase:
iv. CBN Substation reinforce to 300 MVA (future project).
The Mount Lehman Substation Upgrade project comprises the first phase of upgrades.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Project Impacts and Benefits:	
• Increase capacity in the Abbotsford area to ensure that BC Hydro can continue to reliably meet the needs of existing and future customers for the next 10 years or more. • Enable safety improvements at CBN substation. • Improve safety by enabling the decommissioning of SMW substation.	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: N/A	

Investment Planning ID: 92910	**Project Name:** Clayburn Substation Upgrade	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Identification	**Filing Reference:** F17-F19 RRA: • Appendix I, line 37 • BCUC IRs 1.70.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1	

Description:

The purpose of the Clayburn Substation Upgrade project is to reduce safety risks, and restore and upgrade the substation's 25 kV feeder capacity to 200 MVA.

Key Drivers:

- Reliability
- Safety

Issues Being Addressed:

The Abbotsford area is currently supplied by the Mount Lehman (**MLE**), Clayburn (**CBN**), Sumas Way (**SMW**) and Gloucester (**GLT**) substations. At present, the total capacity of these four stations is 360 MVA.

The general strategy for the area is to expand the MLE substation, address safety issues at the CBN substation, and decommission the SMW substation.

At CBN substation, the existing 25 kV feeder sections are outdoor compact air insulated switchgear with inadequate clearances to energized equipment. These require extended outages for routine operation and maintenance. However, opportunities to take the required outages at CBN substation have been very limited, due to the unacceptable impact on customers. As a result of the safety issues associated with performing work, coupled with the challenges with finding appropriate outage times, maintenance on the CBN substation feeder sections has been postponed indefinitely.

Discussion of Alternatives:

This project was identified as a result of a 30-year study carried out for the Abbotsford area in 2013 to mitigate safety issues at SMW and CBN substations and address capacity shortage in the Abbotsford area. The area study resulted in three alternative solutions being identified and reviewed. The alternative comparison was a comparison of different implementation strategies to determine not only what should be done, but also their timing. These were re-evaluated during the Identification Phase of the Mount Lehman Substation Upgrade project. A leading alternative was accepted that includes three phases of upgrades and four major projects:

First Phase:

i. MLE Substation Expansion to 170 MVA (ultimate 200 MVA) (Investment Planning ID: 92907);

Second Phase:

ii. CBN Substation reinforce to 200 MVA (this project);

iii. SMW Substation Decommissioning (Project release after fiscal 2023); and

Third Phase:

iv. CBN Substation reinforce to 300 MVA (future project).

The Clayburn Substation Upgrade project is the first project in the second phase of upgrades. It is considered the only viable alternative since no other alternative will meet the objectives of the accepted overall solution for the Abbotsford area.

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">Project Impacts & Benefits:
Improve reliability in the Abbotsford area by restoring the capacity of CBN substation to 200 MVA.
Improve safety at CBN substation.
Improve safety by enabling the decommissioning of SMW substation.</td></tr>
<tr><td>Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="2">Additional Information:
N/A</td></tr>
</table>

[redacted]

[1] Start Date of Construction is the Implementation Approval Date.

[redacted]

Investment Planning ID: 900816	**Project Name:** Pemberton - Substation Upgrade	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Future	**Filing Reference:** New	

Description:

This project will address reliability risks associated with the load exceeding the firm capacity of the Pemberton (**PEM**) Substation, as well as end-of-life and polychlorinated biphenyl (**PCB**) contaminated equipment.

Key Drivers:

- Reliability
- Safety
- Environmental

Issues Being Addressed:

The current load at the PEM Substation exceeds the station's current firm capacity of 22 MVA. This capacity shortfall will be exacerbated in the future, as there are several load interconnection requests from customers.

There are also a number of reliability and safety risks associated with some of the equipment, namely:

- The poor condition of the 230 kV and 25 kV wood pole structures;
- Two 25 kV bulk oil circuit breakers are in poor condition and contain PCB levels above the allowable amounts, requiring phase out by the end of 2025; and
- Limited space between equipment poses safety risks for workers due to limited clearance between energized equipment and ground and lengthy outages are required to safely perform work.

Discussion of Alternatives:

The alternatives being considered include:

i. **Build a new station and decommission existing PEM station:** This alternative will build a new station at a new site, and decommission the existing substation;
ii. **Rebuild the station** at the existing site: This alternative will rebuild the station at the existing site and decommission some of the ageing assets;
iii. **Install a modular substation** This alternative will address growth needs. This alternative would also replace end-of-life and PCB contaminated equipment at the existing site; and
iv. Do nothing.

Project Impacts and Benefits:

- Increase reliability in the area served by PEM station.
- Increase the firm capacity of PEM station.
- Remove equipment with PCB levels at or above 50 ppm by the December 31, 2025 Federal Regulation deadline.
- Address safety concerns at PEM station.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

[1] Start Date of Construction is the Implementation Approval Date.

Additional Information:
N/A

<table>
<tr><td>Investment Planning ID:
900243</td><td colspan="2">Project Name:
SPG Metalclad Switchgear Replacement</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td>Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
New</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to improve the reliability at Sperling Substation (SPG).</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Safety</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The 60 series feeder section consists of 12 kV bulk oil breakers and a lattice steel structure built for 4 kV prior to 1950. The 60 series feeder section and the bulk oil breakers in the 70/80 series feeder section are at end of life. One breaker in the feeder section has failed, and more breaker failures are expected in the near future. The 60 series feeder section also has insufficient Limits of Approach to protect worker safety. The existing lattice structure does not meet current seismic requirements and is at end-of-life due to aging and corrosion.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
Five alternatives were considered during the Needs stage including:
i. Do nothing and defer the work;
ii. Replace only the bulk oil breakers in the 60 series feeder section;
iii. Replace the existing 60 series feeder section, the bulk oil breaker in the 70/80 series feeder section and four end-of-life electromagnetic protection relays in the substation: the non-arc resistant metalclad switchgears would be replaced with new arc-resistant switchgears;
iv. Decommission SPG and transfer load to other stations; and
v. Replace SPG with a new substation.
Alternative iii, Replace the existing 60 series feeder section, the bulk oil breaker in the 70/80 series feeder section and four end-of-life electromagnetic protection relays in the substation, was selected as the preferred alternative. The non-arc resistant metalclad switchgears will be replaced with new arc-resistant switchgears. This was considered to be the only viable alternative to address the reliability and safety issues at SPG.</td></tr>
<tr><td colspan="3">Project Impacts & Benefits:
• Replacement of the 60 series feeder section with indoor switchgear improves reliability
• Addresses the Limits of Approach (Safety) by using a smaller footprint than other options, resulting in fewer space constraints at SPG.</td></tr>
<tr><td colspan="2">Project Implementation Phase Risk
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="3">Additional Information:
N/A</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td>Investment Planning ID:
900575</td><td colspan="2">Project Name:
Barnard 50/60 Feeder Section Replacement</td></tr>
<tr><td>Forecast Capital Cost:
$66.0 million to $37.4 million</td><td>Forecast In-Service Date:
Fiscal 2022</td><td>Start Date of Construction:[1]
Fiscal 2019</td></tr>
<tr><td>Development Phase:
Definition</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• Appendix I, line 46, Appendix J, page 72
• .BCUC IRs 1.70.3, 2.249.8, 2.264.4, BCOAPO IR 1.36.1</td></tr>
<tr><td colspan="3">Description:
The purpose of this project is to replace the 12 kV Feeder Section 50/60 series, 230 kV and 12 kV protection and control equipment and telecommunication assets at Barnard Substation.</td></tr>
<tr><td colspan="3">Key Drivers:
• Reliability
• Safety</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Barnard Substation 50/60 feeder section equipment, installed between 1950 and 1955, has reached end of life, resulting in increased reliability and safety risk. The Asset Health Index rating on the electrical equipment in the feeder section (e.g., bulk oil breakers and disconnect switches) is Very Poor. Failures may cause safety hazards and potentially long outages to impacted feeders. The design of the feeder section is obsolete and there are clearance issues associated with the equipment leading to increased safety risks. Maintenance work cannot be performed safely without significant time and expense to offload feeders.
The identified 230 kV and 12 kV protection and control and telecommunication equipment in the substation is over 50-years old and has reached end of life and need replacement.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
The following alternatives were assessed during Identification Phase:
i. Replace Feeder Section 50/60 and replace aging protection, control and telecommunication equipment; and
ii. Do Nothing.
Alternative i, Replace Feeder Section 50/60 and replace aging protection, control and telecommunication equipment, was selected as the preferred alternative. This was the only alternative that met the project objectives of addressing the reliability risk of the end-of-life equipment and minimizing worker safety risks.</td></tr>
<tr><td colspan="3">Project Impacts and Benefits:
• Improved reliability for customers served through the Barnard Substation.
• Improved worker safety</td></tr>
<tr><td colspan="2">Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="3">Additional Information:
N/A</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: 900247	**Project Name:** BR1 T3 & BRT T4A Replacement	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Identification	**Filing Reference:** New	

Description:

The purpose of this project is to improve the reliability, and reduce the environmental and safety risks associated with transformer T3 and the 12 kV assets at Bridge River 1 Generating Station (**BR1**) and T4 Transformers at Bridge River Terminal (**BRT**).

Key Drivers:

- Reliability
- Environmental
- Safety

Issues Being Addressed:

Reliability risks due to transformer health:

- Phases A, B and spare of transformer T4 at BRT substation are all approaching end of life. Asset health indicators for phases A and B are 'poor'. A significant failure of these phases could cause an extended reduction in the ability to transmit power from the Bridge River system; and
- Transformer T3 at BR1 substation has an asset health indicator of 'very poor' indicating the unit is near end of life.

Environmental risks: A significant failure of transformer T3 may result in an oil release to Seton Lake with environmental impacts.

Other asset reliability and safety issues: The 12 kV system at BR1 requires redevelopment because of aging equipment, limits of approach violations and other safety concerns.

Discussion of Alternatives:

For the BRT – T4 system, three alternatives will be evaluated during the Identification Phase:

i. **Remove phase A** and replace it with a refurbished Phase D, obtain a new spare single phase transformer, add oil containment and passive fire protection;
ii. **Replace phase A & phase B** with new single phase transformers, refurbish phase D for use as a spare transformer, add oil containment and passive fire protection; and
iii. **Replace all three phases of T4** with a new three-phase transformer, obtain an additional new three-phase transformer for use as a spare, add oil containment and passive fire protection.

For the BR1 – T3 the following four alternatives will be evaluated during Identification Phase:

i. Replacement;
ii. Do Nothing;
iii. Deferral; and
iv. Decommissioning.

For the 12 kV system, the following three alternatives will be evaluated during Identification Phase:

i. Replacement;
ii. Do Nothing; and
iii. Deferral.

[1] Start Date of Construction is the Implementation Approval Date.

Project Impacts and Benefits: • Improve reliability of T4 at BRT, as well as transformer T3 and the 12 kV assets at BR1. • Reduce potential environmental risks associated with transformer T3. • Reduce potential safety risks associated with the 12 kV system.	
Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when project reaches Implementation.
Additional Information: The Bridge River System lies within the traditional territory of the St’át’imc Nation. BC Hydro and St’át’imc have a set of Agreements (signed in 2011) that settle all past, present and future claims related to the Bridge River facilities and provide legal certainty around continued operations of the Bridge River facilities and inform ongoing relationship development. BC Hydro is engaging the St’át’imc Nation in a manner consistent with our Agreements and continues to work with the St’át’imc to address issues and concerns around this project	

Investment Planning ID: 93731	**Project Name:** JOR T1 & T2 Replacement	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Identification	**Filing Reference:** New	

Description:

The purpose of the project is to improve the reliability, and reduce the safety and environmental risks at the Jordan River (**JOR**) substation.

Key Drivers:

- Reliability
- Safety
- Environmental

Issues Being Addressed:

Transformers T1 and T2 are 48 years-old and have numerous deficiencies, including the lack of monitoring gauges, lack of effective cooling, leaking bushings and significant oil leakage from the main tanks with no oil containment. T2 is being closely monitored due to elevated levels of combustible gasses which caused an outage in 2015. T1 and T2 are unique transformers with no system spares.

The transformers are in close proximity to each other and other equipment, and there is insufficient clearance between the equipment to allow access for maintenance and fire protection.

The facility was constructed with no fire barriers or oil containment which would reduce collateral or environmental damage in the event of a catastrophic failure. This exposes both units to risk of a single event, such as a failure of either unit or a circuit breaker, reducing both worker safety and expected reliability. Elimination of this risk is a project objective.

Circuit breakers, disconnect switches, instrument transformers and voltage regulators at JOR are in a deteriorated state. The switchyard does not meet current safety, environmental and seismic standards.

Discussion of Alternatives:

Five alternatives were evaluated during Identification phase:

i. **Like for like replacement** of end of life equipment (was considered not viable);
ii. **Transformer replacement with separate distribution transformers** (was considered not viable);
iii. **Transformer replacement and switchyard expansion**;
iv. **Single-phase step-up transformers**; and
v. **Transformer replacement and switchyard expansion and pad mount distribution transformers**. The two step-up transformers will be replaced, and a portion of the switchyard will be rebuilt. Distribution voltage connection would be through two new pad mounted transformers.

Alternative v, Transformer replacement and switchyard expansion and new pad mount distribution transformers, was selected as the leading alternative because it was the lowest cost viable alternative that addressed the reliability and safety risks.

Project Impacts and Benefits:

- Reduce reliability, environmental and safety risks by reconfiguring the substation, expanding the switchyard and replacing the aging equipment.

[1] Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.
Additional Information: Construction on the JOR Upgrade Governor & PRV Controls project (G000158) is likely to occur during the same period. The JOR Upgrade Governor & PRV Controls project requires an outage from March to early September 2021. The substation work will coordinate outages with the JOR Upgrade Governor & PRV Controls project.	

<table>
<tr><td colspan="1">Investment Planning ID:
92478</td><td colspan="2">Project Name:
Mainwaring Station Upgrade</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td>Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Identification</td><td colspan="2">Filing Reference:
2014 Annual Report to the BCUC:
• Appendix I, line 15;
• Appendix J, page 57.
F17-F19 RRA:
• Appendix I, line 43, Appendix J, page 69
• BCUC IRs 1.70.3, 1.110.5, 2.249.8, 2.253.2, 2.254.1.1, 2.260.4, 2.267.2, BCOAPO IR 1.36.1, CECBC IR 1.78.1</td></tr>
</table>

Description:

The purpose of this project is to improve the safety, environmental and reliability issues at Mainwaring Substation.

Key Drivers:

- Reliability
- Safety
- Environmental

Issues Being Addressed:

Transformers T1 and T3 are approximately 60-years old and nearing end of life, resulting in increased reliability risk. Both transformers have no on-load tap changers (**OLTC**) resulting in the need for 40 voltage regulators on the feeder positions. The majority of the voltage regulators are in poor condition.

The feeder sections are nearing end of life resulting in increased reliability and safety risk. Many of the circuit breakers and voltage regulators contain oil with PCB concentrations above the federal PCB regulation threshold and are required to be removed by 2025. The feeder section has clearance issues and poses safety risks for workers.

Discussion of Alternatives:

For transformers T1 and T3, three alternatives were evaluated during Identification Phase:

i. **Ongoing sustainment** of individual assets as they fail or reach end of life;

ii. **Extend and upgrade the existing substation** to replace the T1 and T3 transformers; and

iii. **Build a new substation** in the Metrotown area.

Alternative ii, Extend and upgrade the existing substation, was selected as the leading alternative because it is expected to cost less, have fewer stakeholder issues, and can be completed six years earlier than Alternative iii.

For the 50/60 Series Feeder Section, two alternatives will be evaluated during Identification Phase:

i. **Add** a new indoor gas insulated (**GIS**) feeder section; and

ii. **Refurbish** the existing 50/60 series feeder section.

Project Impacts and Benefits:

- Reduce reliability, environmental and safety risks by extending and upgrading the substation.

[1] Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.
Additional Information:	
N/A	

Investment Planning ID: 900152	**Project Name:** Natal Sub – NTL 60-138 kV Rebuild	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Identification	**Filing Reference:** New	

Description:

The purpose of the project is to improve the reliability and reduce environmental risks at Natal (**NTL**) substation.

Key Drivers:

- Reliability
- Environmental

Issues Being Addressed:

Originally built in 1946, NTL is a transmission substation in southeast B.C. region. NTL is a point of intertie with the Alberta transmission system. NTL is also connected to several other BC Hydro substations at 60 kV, 138 kV, and 230 kV as well as multiple transmission voltage customers.

The main issues and risks at NTL are:

- Reliability: The power transformers, voltage regulators, circuit breakers, disconnect switches, instrument transformers, control building and many protection relays in the 60 kV to 138 kV switchyard are in poor condition; and
- Environmental: Two circuit breakers contain PCB contaminated oil. Current Federal PCB Regulations require the phase out of electrical equipment containing PCB levels of 50 ppm or more by 2025.

Discussion of Alternatives:

Four alternatives were evaluated during Identification Phase:

i. **Within the existing site, replace the NTL 60 kV to 138 kV switchyard,** end of life equipment, and the control building;
ii. **On a new property, replace the NTL 60 kV to 138 kV switchyard,** end of life equipment, and the control building;
iii. **Replace the NTL 60 kV to 138 kV switchyard considering 138 kV to 230 kV transformation** and new, smaller 60 kV switchyard; and
iv. **Do nothing or deferral.**

Alternative i, Within the existing site, replace the NTL 60 kV to 138 kV switchyard, end of life equipment, and the control building, was selected as the leading alternative. This alternative will address the current health and condition of the existing 60 kV to 138 kV station, which poses unacceptable reliability risks. Consideration was given to ensure sufficient space is available on the existing property and the acquisition of new property is not required. This alternative maintains power supply to customers during the construction period.

Project Impacts and Benefits:

- Reduce reliability risks by replacing the NTL Substation 60 kV to 138 kV switchyard, and associated control building.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

[1] Start Date of Construction is the Implementation Approval Date.

Additional Information:
N/A

<table>
<tr><td colspan="4">Program of Projects Name: Peace Region to Kelly Lake - Reactor Replacement</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td colspan="4">Appendix I Reference:
Transmission, page 5, lines 36 and 40.</td></tr>
<tr><td>Investment Planning ID:
900884</td><td colspan="3">Project Name:
Peace Region to Kelly Lake - Reactor Replacement (Phase 1)</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td colspan="2">Forecast In-Service Date: TBD:</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td colspan="2">Development Phase:
Identification</td><td colspan="2">Filing Reference:
New</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td>Investment Planning ID:
900185</td><td colspan="3">Project Name:
Peace Region to Kelly Lake - Reactor Replacement (Phase 2)</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td colspan="2">Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td colspan="2">Development Phase:
Future</td><td colspan="2">Filing Reference:
New</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td colspan="4">Description, Objectives and Scope of Program of Projects:
This program of projects was defined to replace ageing 500 kV shunt reactors from the Peace Region to Kelly Lake Substation. A Program Delivery Strategy will be developed during the Identification phase of Phase 1 of the program. This delivery strategy will focus on identifying the most efficient and cost effective model to deliver the subsequent projects within the program.
The objective of this project is to replace 2 reactors as part of a larger program addressing end-of-life units at G.M. Shrum (5RX1, 5RX2), Williston (5RX2, 5RX3, 5RX4, 5RX5, 5RX7) and Kelly Lake (5RX1, 5RX3) according to a ranked priority that is based on the condition assessment. Most of the reactors are single phase units with the exception of Williston 5RX7.
These reactors are required for the operation of the 500 kV bulk transmission system from the Peace Generation system. Failure of any one of the reactors will result in unacceptably high voltage in the 500 kV system, and affect the continued operation of the 500 kV system.</td></tr>
<tr><td colspan="4">Schedule of Program of Projects:
The program strategy will consider replacement of these reactors over a period of 11 years.</td></tr>
<tr><td colspan="4">Risks and Mitigation Strategies:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.
The risk mitigation will be determined when the project reaches Definition phase.</td></tr>
<tr><td colspan="4">Additional Information:
This is an Appendix J for a Program of Projects as outlined in the Revised Proposal, Appendix B, item 6 (k), filed with the BCUC on June 13, 2018.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: **901034**	**Project Name:** **Norgate - Substation Upgrade**	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Future	**Filing Reference:** New	

Description:

This project will address end of life equipment and remove polychlorinated biphenyl (PCB) contaminated equipment at Norgate (**NOR**) substation.

Refer to the following Appendix Ks for additional information: Integrated Planning Report for Capilano and Lynn Valley Substations and Distribution Area, and Asset Management Strategy – Section 2.2.2: Circuit Breakers for additional information.

Key Drivers:

- Reliability
- Environmental

Issues Being Addressed:

The following are the main issues at the Norgate substation that will be addressed as part of this project:

- The poor condition of three power transformers which are subject to oil leaks;
- The poor condition of the voltage regulators in the feeder section which contain polychlorinated biphenyl (**PCB**) at levels at or above 50 ppm which will be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline;
- The poor condition of a significant portion of the circuit breakers, reactors, protection and control assets, and disconnect switches; and
- Safety issues related to limited clearance between energized equipment and ground in the feeder section.

Discussion of Alternatives:

Alternatives to be considered include:

i. **Do nothing**;
ii. **Address** environmental compliance requirements only;
iii. Replace/Refurbish the transformers and 12 kV feeder section; and
iv. **Transfer** the load to the neighboring stations and decommission the transformers and the feeder section.

Project Impacts and Benefits:

- Address reliability risks at NOR substation.
- Comply with Federal PCB Regulations.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

N/A

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: Multiple	**Program Name:** NERC CIPv5 Compliance	
Forecast Capital Cost:[1] $40.1 million	**Forecast In-Service Date:**[2] In Compliance of NERC CIP v5 requirements by October 2018. In-Service date of fiscal 2023 for non-regulated enhancements.	**Start Date of Construction:**[3] Fiscal 2017
Development Phase: Multiple (In-service and Implementation)	**Filing Reference:** F17-F19 RRA: • Appendix I, line 47, Appendix J, page 73, • BCUC IRs 1.70.3, 1.111.1 to 1.111.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1	

Description:

BC Hydro achieved compliance with NERC CIP Version 5 by October 1, 2018.

The NERC CIP v5 Compliance initiative consists of five projects and work packages covering five business groups (Technology, Physical Security, Generation Stations, Transmission Stations, and Grid Operations) focused on compliance efforts as indicated below:

1. Transmission Stations – addresses Transmission based Cyber Assets;
2. Generation Stations – addresses Generation based Cyber Assets;
3. Grid Operations – addresses Grid based Cyber Assets;
4. Technology – addresses IT and Physical Security Cyber Assets; and
5. Physical Key Management Work Package– addresses physical spaces containing Cyber Assets.

The purpose of the initiative is to upgrade electronic and physical security for computer/electronic equipment used to control and monitor the Bulk Electric System (**BES**) to meet the standard defined by the North American Electric Reliability Corporation (**NERC**).

The Generation, Grid Operations, and Technology projects and related Physical Key Management work are now in-service; with no remaining capital spend in fiscal 2020 or later.

The Transmission Stations project is continuing in Implementation, in order to extend use of the Station Gateway System and automate a number of manual compliance processes to facilitate on-going sustainment. This effort will exceed NERC CIPv5 compliance requirements, and is expected to complete in fiscal 2023.

Key Drivers:

- Reliability
- Reputational
- Financial Loss

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1 Forecast Capital Cost was $40.1 million at December 31, 2018.

2 There are multiple in-service dates within the program, the latest of which is for the automation of processes at Medium Impact T&D Stations in fiscal 2023. All requirements under NERC CIPv5 under this program were met by October 1, 2018.

3 There are multiple Start Dates of Construction (Implementation Approval Dates) the earliest of which was for the Technology NERC CIP v5 project, having Start Date of Construction in fiscal 2017.

<table>
<tr><td colspan="2">Issues Being Addressed:
NERC Critical Infrastructure Protection (CIP) Reliability Standard Version 5 was adopted in B.C. by the Commission in July 2015. Through Commission Order No. R-38-15, BC Hydro reached compliance with Version 5 of the standard by October 2018, which has been met</td></tr>
<tr><td colspan="2">Discussion of Alternatives:
None.</td></tr>
<tr><td colspan="2">Project Impacts and Benefits:
• Meet regulatory (NERC CIP Version 5) requirements.
• Improve overall cyber security of BES Cyber Assets.
• Mitigate risk of financial penalties for non-compliance.</td></tr>
<tr><td>Project Implementation Phase Risk:
The ongoing Transmission Stations project currently does not have any identified Zone 3 (high) Implementation Phase risks.</td><td>Risk Treatment:
N/A</td></tr>
<tr><td colspan="2">Additional Information:
Forecast Program capital cost information is provided as of December 31, 2018 in order to present a recent, consolidated forecast of program costs, reflecting the in-service status of the majority of NERC CIP v5 projects and work packages. The forecast cost of the Transmission Stations portion of the program cost is $31.2 million to $17.7 million as provided in Appendix I.</td></tr>
</table>

<table>
<tr><td>Investment Planning ID:
92183</td><td colspan="2">Project Name:
Vancouver Island Microwave Radio System</td></tr>
<tr><td>Forecast Capital Cost:
$32.5 million</td><td>Forecast In-Service Date:
Fiscal 2021</td><td>Start Date of Construction:[1]
Fiscal 2018</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
New</td></tr>
</table>

Description:

The purpose of this project is to replace discontinued microwave radios and multiplexing equipment and incorporate Multi Protocol Label Switching (**MPLS**) at 31 existing sites on Vancouver Island.

The system will be extended to Gold River Substation (**GLD**) and will replace aging Power Line Carrier (**PLC**) systems, increase the communications bandwidth in this area, and allow for high-speed connectivity into Strathcona (**STR**) and Ladore (**LDR**) generating stations.

Key Drivers:

- Reliability

Issues Being Addressed:

The issues and risks associated with the BC Hydro Telecommunication system on Vancouver Island include:

- Equipment reliability and repair issues due to aging equipment that is no longer manufactured or supported by the manufacturer; and
- Lack of communications capacity in the existing telecommunication system to support the increasing communication needs for the existing plants and the new capital projects in progress and planned on Vancouver Island.

Discussion of Alternatives:

Three alternatives were considered in Identification Phase:

i. **Replace** equipment that will not be supported after 2018 **and extend** the Microwave network to GLD;

ii. **Replace** equipment that will not be supported after 2018; and

iii. **Do nothing:** Continue to use the existing microwave radio, multiplexing, and grooming equipment.

Alternative i' Replace equipment that will not be supported after 2018 and extend the Microwave network to GLD, is the preferred alternative as it will improve system reliability and ensure sufficient capacity on the Vancouver Island Power Line Carrier system. MPLS is a network technology that increases the efficiency of transporting Telemetry and Control (**SCADA**), Corporate LAN, voice, and operational traffic.

Project Impacts and Benefits:

- Improve reliability of the microwave radio system.
- Improve operating capacity of the microwave radio system.
- Improve the capacity of the powerline carrier to GLD by replacing it with a microwave system

Project Implementation Phase Risk:	**Risk Treatment:**
This project currently does not have any identified Zone 3 (high) Implementation Phase risks	N/A

Additional Information:

N/A

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: **92768**	**Project Name:** **Various Sites - Microwave System Project Telecom MPLS and DACS Upgrade**	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Future	**Filing Reference:** New	

Description:

This project will implement a new smaller Digital Access and Cross-connect System (**DACS**) for teleprotection to address end of life issues with the existing DACS equipment, and Multi-Protocol Label Switching (**MPLS**) equipment that will allow for more efficient use of telecom capacity.

Refer to Appendix K – Asset Management Strategy – Section 2.4.1 and 2.4.2: Fibre Optic & Microwave Equipment for additional information.

Key Drivers:

- Reliability
- Safety

Issues Being Addressed:

Key components of the telecommunications system that directly support the reliability and safety of the Transmission system are at end of life, no longer available for replacement, and no longer supported by the vendor. This project will upgrade these components. The project will also ensure that the telecommunications system continues to meet NERC reliability standards.

Discussion of Alternatives:

Alternatives considered for the project include:

i. **Do nothing:** Run until failure. In time, teleprotection, grid control, and remedial action schemes will not operate effectively so the transmission system will not be safe or reliable. This alternative is rejected;

ii. **Defer:** Defer the upgrade of the DACS by five years. Refurbishing and sourcing used products from the reseller market is becoming increasingly difficult. This alternative would allow for the vendor market to evolve the MPLS or other technology solutions to meet the needs of teleprotection and potentially simplify the solution being implemented; and

iii. Upgrade: Implement a new smaller DACS for teleprotection and MPLS equipment.

Project Impacts and Benefits:

- Increase the reliability of the telecommunications supporting the bulk electric system.
- Add telecommunications services (such as corporate LAN) to BC Hydro sites which do not currently have corporate services.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

Additional Information:

N/A

[1] Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: 901002	Project Name: 2L146 - Cable Replacement	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Identification	**Filing Reference:** New	

Description:

The purpose of this project is to address reliability and environmental risks associated with the poor asset health of 2L146 cable.

Key Drivers:

- Reliability
- Environmental

Issues Being Addressed:

Circuit 2L146 is a 230 kV direct buried oil-filled cable that runs 7.1 km between Horsey substation (**HSY**) and Goward substation (**GOW**) in Victoria. It has been in service since 1976 and has a history of leaks. The cable is in proximity to environmentally sensitive areas, fish habitat and salmonid spawning grounds. Continued oil leaks could have ecological impact on such sensitive areas, and impact community base restoration efforts targeted to improve the habitat value. In recent years, there have been at least seven leaks on the circuit, including one which resulted in oil contaminating Colquitz Creek. Many of the circuit's joints were also gassing thus requiring replacement; more replacements are expected to be required in the future.

In addition, 2L146 was identified as being at high risk for failure during an earthquake in the recent seismic review. Currently, the circuit has an asset health index grade of Very Poor. Failure of this cable would mean that Goward, Horsey, or Esquimalt substations would be reliant on a single circuit and would be at risk of total station outages for six weeks to one year if a concurrent outage occurred on any one of the other circuits supplying this area (2L143, 2L144 or 2L145). This represents up to 375 MVA of load in the Victoria area at risk in the event of a concurrent outage on any of the other circuits.

Based on load forecasts for the Southern Vancouver Island region and a desire to prevent overloads on existing circuits, the existing 2L146 cable will not provide sufficient capacity to meet the local load following a single contingency event after fiscal 2025. This would result in load shedding in the Victoria area and a violation of NERC planning standards.

Discussion of Alternatives:

Three alternatives were evaluated during Identification Phase:

i. **Do nothing / deferral:** This option would defer the replacement of the cable for five years, which may lead to a reactive replacement and increased system risk. This increased risk of circuit failure would leave Horsey and other Victoria substations with diminished reliability for extended periods;

ii. **Replace:** Replace the existing cable with a new cable with the existing rating. It would be installed in a new duct bank and use solid dielectric insulation. However, it would not address the overload issues expected in the future; and

iii. **Upgrade:** Upgrade by replacing the existing cable with a new cable capable of meeting load growth in the future. It would be installed in a new duct bank to improve maintainability and would have solid dielectric insulation to eliminate the risk of oil leaks.

Alternative iii, Upgrade the cable, was selected as the only viable alternative for the project that will meet future load growth.

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="2">Project Impacts & Benefits:
• Ensure that future load growth can be met.
• Improve reliability associated with Very Poor asset health.
• Reduce environmental risks associated with the 2L146 cable.</td></tr>
<tr><td>Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="2">Additional Information:
N/A</td></tr>
</table>

<table>
<tr><td colspan="2">Investment Planning ID:
94057</td><td colspan="2">Project Name:
Gulf Islands - Transmission Reinforcement</td></tr>
<tr><td colspan="2">Forecast Capital Cost:
TBD</td><td>Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td colspan="2">Development Phase:
Future</td><td colspan="2">Filing Reference:
New</td></tr>
<tr><td colspan="4">Description:
This investment will reinforce the transmission supply to the Gulf Islands in order to mitigate the risk of failure on circuit 1L18.
For additional information, refer to Appendix K – Asset Management Strategy – Section 2.1.10: Transmission Cables.</td></tr>
<tr><td colspan="4">Key Drivers:
• Reliability</td></tr>
<tr><td colspan="4">Issues Being Addressed:
The Gulf Islands are supplied by a 138 kV circuit, 1L18, which has two sections of submarine cable: one that runs from the mainland to Galiano Island under the Georgia Strait, and a second between Galiano Island and Saltspring Island under Trincomali Channel. Recent inspections have determined that the section of this circuit in the Georgia Strait is reaching end-of-life. This project will ensure the reliability of supply for the Gulf Islands by supplying the Saltspring substation from a second existing circuit.</td></tr>
<tr><td colspan="4">Discussion of Alternatives:
Alternatives identified for this project include:
i. Supply Saltspring substation from circuit 2L129: This alternative would add a second supply to the Saltspring substation by installing a transformer and minor transmission line upgrades;
ii. Replace the Georgia Strait cables: This alternative would replace the existing cables in the Georgia Strait with new cables. This would address the immediate concern with the cable’s condition; and
iii. Replace the Georgia Strait and Trincomali Channel cables: This alternative would replace the existing cables in the Georgia Strait and Trincomali Channel with new cables. This will address the risks related to the cable’s deteriorated condition in Georgia Strait and the aged cables in Trincomali Channel.</td></tr>
<tr><td colspan="4">Project Impacts and Benefits:
• Address reliability risks associated with the end-of-life cable.</td></tr>
<tr><td colspan="3">Project Implementation Phase Risk:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.</td><td>Risk Treatment:
To be determined when the project reaches Implementation.</td></tr>
<tr><td colspan="4">Additional Information:
N/A</td></tr>
</table>

1 Start Date of Construction is the Implementation Approval Date.

Investment Planning ID: **94035**	**Project Name:** **5L63 Telkwa Relocation**	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Identification	**Filing Reference:** F17-F19 RRA: • Appendix I, line 45, Appendix J, page 71 • BCUC IRs 1.70.3, 2.249.8, 2.260.4, BCOAPO IR 1.36.1	

Description:

The purpose of the project is to continue reliable transmission of electricity on 5L63 by relocating the line segment currently situated in an active landslide area.

Key Drivers:

- Safety
- Reliability

Issues Being Addressed:

Northwest British Columbia, including the communities of Prince Rupert, Terrace, Kitimat and Smithers are interconnected by a series of 500 kV transmission lines: 5L61, 5L62 and 5L63. Circuit 5L63, built in 1973 / 74 is a 500 kV radial transmission system between Telkwa Substation (**TKW**) and Skeena Substation (**SKA**). As a radial feed, the reliability of this line is essential for this large region of the province.

A section of transmission line 5L63 crosses the landslide area known as the “bulbous toe”. One tower is located in the geotechnically unstable area which has been gradually sliding downhill for approximately 35 years resulting in the tower moving approximately 0.3 metres per year. The continued movement of the tower is leading to a growing risk of catastrophic failure.

The movement is also creating a safety risk to crews performing maintenance on this tower as they are running out of margin to safely adjust guy wires and insulator strings on the tower. There is also a risk that a sudden landslide would destroy the tower and sever the line resulting in an extended outage in the area.

Discussion of Alternatives:

Four alternatives were evaluated during Identification Phase:

i. **Do nothing,** continue to maintain;
ii. **Defer** risk mitigation;
iii. **Do nothing but acquire spares** and pre-plan an emergency response; and
iv. **Relocate** 5L63 away from landslide area.

Alternative iv, Relocate 5L63 away from landslide area, was selected as the only viable alternative for the project, as the other alternatives would not reduce the reliability and safety risks.

Project Impacts and Benefits:

- Improve the reliability of 5L63 and the large region of the province that it serves.
- Address safety risks associated with the section of 5L63 in a landslide area.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation.

[1] Start Date of Construction is the Implementation Approval Date.

Additional Information:
BC Hydro is targeting completion of the project for March 2021 to accommodate customer load interconnection requirements.

Program of Projects Name: H-Frame Elimination - Chinatown		
Appendix I Reference: Distribution, page 7, line 21.		
Investment Planning ID: **900557**	**Project Name:** **H-Frame Elimination – Chinatown**	
Forecast Capital Cost: $48.4 million	**Forecast In-Service Date:** Fiscal 2020	**Start Date of Construction:**[1] Fiscal 2016
Development Phase: Implementation	**Filing Reference:** F17-F19 RRA: • BCUC IRs 1.77.2, 2.307.3	

Description, Objectives and Scope of Program of Projects:

This Program of Projects will eliminate the safety hazards associated with the distribution lines built on H-Frame structures located in back lanes in the Chinatown area of Downtown Vancouver by constructing new underground feeders and relocating overhead feeders and services to the new underground system. Approximately 110 H-Frame structures have primary conductors that do not meet current safety clearances relative to the existing buildings. This close proximity to fire escapes and windows in the back lanes of buildings poses a significant safety risk to the public. In many of the narrow back lanes, it is not possible to bring the H-Frame system into compliance with current safety clearance codes and standards. The objective of the project is to reduce the risk of public contact incidents from these H-Frames.

The scope of the Program of Projects includes:

- Relocating electrical equipment underground in new civil infrastructure to reduce the potential public electrical contact hazard. This will also mitigate the risk of vandalism as well as improve the visual aesthetics of the area; and
- Aligning the work with the Downtown Vancouver Electric Supply Plan.

Schedule of Program of Projects:

The planned in-service dates for the various projects within the program are summarized as follows:

- Primary System Projects – October 31, 2019
  - Columbia & Pender;
  - Main & Powell;
  - Gore & Pender; and
  - Main & Georgia;
- Secondary System Projects – March 31, 2020:
  - Columbia;
  - Main & Powell;
  - Gore & Pender; and
  - Main & Georgia;
- Automation/Fibre Project – October 31, 2019; and
- Dismantling/Removal Project – March 31, 2020.

[1] Start Date of Construction is the Implementation Approval Date.

Risks and Mitigation Strategies:

Risks include:

- The timely development of new or enhanced equipment standards (e.g., to interconnect in-building switchgear to the primary open loop system) and the procurement of long lead time underground equipment (vaults, submersible transformers and switchgear). Any delays in finalizing standards or procuring equipment may delay construction schedules. This risk is being mitigated by identifying any potential deficiencies or risks in early design phases and by placing early pre-orders of long lead time equipment;
- Identifying acceptable locations for underground vault and above ground control enclosures with the City of Vancouver and impacted stakeholders. This is a challenge due to the congested underground infrastructure in Downtown Vancouver. This risk is being mitigated through regular interactions with the City of Vancouver and impacted stakeholders during the design phase;
- There are challenges with negotiating upgrades to customer-owned secondary electrical infrastructure due to a lack of interest or responsiveness from some customers, or difficulty identifying or contacting building owners (e.g., owners may reside outside B.C. or Canada or the building may be owned by a numbered company). This risk is being mitigated through BC Hydro's Community Engagement team involvement in working with the design team and Key Account Managers to help identify building owners, communicate the project objectives, identify the required building modifications and work to obtain signed new Electric Service Agreements; and
- Other construction challenges include limited resources to perform civil work, management of vehicle and pedestrian traffic, congestion with other underground utilities, and limited working hours for construction. These risks are being mitigated by early and frequent engagement with the City of Vancouver and the local Business Improvement Association.

Additional Information:

- This is an Appendix J for a Program of Projects as outlined in the Revised Proposal, Appendix B, item 6 (k), filed with the BCUC on June 13, 2018 as part of the Capital Expenditures and Projects Review. Individual projects within this Program of Projects do not meet the criteria for inclusion in Appendix I.

Investment Planning ID: **900556**	**Project Name:** **Various Sites - LED Street Light Conversion**	
Forecast Capital Cost: TBD	**Forecast In-Service Date:** TBD	**Start Date of Construction:**[1] TBD
Development Phase: Identification	**Filing Reference:** New	

Description:

This project involves the mass conversion of high pressure sodium (**HPS**) street lights to LED street lights.

For additional information, refer to Appendix K – Asset Management Strategy – Section 3.1.8 Street Lighting.

Key Drivers:

- Reputation
- Environmental

Issues Being Addressed:

This Project will address the following:

- Compliance with federal polychlorinated biphenyl (**PCB**) Regulations,
- Mitigation of increasing support and maintenance costs,
- Improvement of customer service and experience,
- Increased data and billing accuracy.

Discussion of Alternatives:

Four alternatives were considered:

i. **Status quo:** Reactive replacement of failed HPS street lights with new bulbs or fixtures. This alternative was rejected;

ii. **Reactive replacement:** Replacement of failed HPS street lights or HPS street lights containing PCBs in a concentration of 50ppm or more with new HPS street lights;

iii. **Reactive Upgrade:** Conversion of failed (or as they fail) HPS street lights to LED street lights; and

iv. **Proactive Replacement:** Mass conversion of all HPS street lights to LED street lights.

Alternative iv, was selected as the leading alternative. It addresses the four key issues identified above; it meets the regulatory requirement, has the lowest lifecycle costs, provides the best customer service and experience, and is technically superior. It also meets the environmental and safety objectives. The other alternatives considered are less efficient and more costly, and do not necessarily meet regulatory compliance and/or improve customer experience and service.

Project Impacts & Benefits:

The expected outcome of this investment is to convert all existing Rate Schedule 1701 Street Lights and Rate Schedule 1755 Private Outdoor Lights from older less efficient High Pressure Sodium (**HPS**) and Mercury Vapour (**MV**) lights to Light Emitting Diode (**LED**) technology.

Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation.

Additional Information:

N/A

[1] Start Date of Construction is the Implementation Approval Date.

<table>
<tr><td colspan="1">Investment Planning ID:
T001127</td><td colspan="2">Project Name:
Supply Chain Applications</td></tr>
<tr><td>Forecast Capital Cost:
$68.0 million</td><td>Forecast In-Service Date:
Fiscal 2020</td><td>Start Date of Construction:[1]
September 27, 2018</td></tr>
<tr><td>Development Phase:
Implementation</td><td colspan="2">Filing Reference:
Amended F12-F14 RRA:
• Application, page 6-71
• Amended Appendix I, page 25
• Amended Appendix J, page 154
• BCUC IRs: 1.204.1, 1.275.0. 1.280.1, 1.280.1.1, 1.433.5, 2.136.1.1, 2.136.2.1, 2.137 Series, 2.139.3, 2.190.1 – Att. 6
• Intervener IRs: AMPC IRs 1.58.1, 1.58.2.1, 1.58.4 and Attachment 1, 1.58.7.
F17-F19 RRA:
• Appendix I, line 2, Appendix J, page 75,
• BCUC IRs 1.70.3, 1.114.2, 1.114.9, 2.249.8, 2.260.4, BCOAPO IR 1.36.1, CECBC IRs 1.72.3.2, 1.117.1 – 1.117.3, 1.118.1-1.118.4, 1.118.4.1, 1.118.4.2, 1.124.1, 1.125.1, 2.165.3, 2.165.4
• BC Hydro Supply Chain Applications Project Application (Phase One Application)
• Decision and Order G-158-17(Phase One Decision)
• BC Hydro Supply Chain Applications Project Phase Two Application(Phase Two Application)</td></tr>
<tr><td colspan="3">Description:
The Supply Chain Applications project involves the design and implementation of new business processes and information technology to support the acquisition of materials and services from third parties.</td></tr>
<tr><td colspan="3">Key Drivers:
• Increased operational efficiency,
• Reduced material and service costs,
• Risk reduction.</td></tr>
<tr><td colspan="3">Issues Being Addressed:
In 2013, BC Hydro approved a new Supply Chain Business Model. An assessment of BC Hydro’s current capability against requirements for the new model identified 13 capability gaps requiring technology and process changes. The SupplyChain Applications Project is intended to address these capability gaps and achieve operational efficiencies, reduced material and service costs and an overall reduction in risk.
In the Phase One Decision the BCUC found that, given the capability gap issues raised, the current supply chain system employed by BC Hydro is inadequate considering the size and complexity of BC Hydro and determined that there is a need to address this.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Discussion of Alternatives:

BC Hydro employs SAP as the information technology platform for its enterprise resource planning functions and system of record. BC Hydro performed an evaluation comparing a SAP-based technology solution to one based on the existing Ventyx PassPort-based technology. The evaluation indicated that an SAP-based technology solution better supports the Supply Chain Business Model and is expected to provide greater overall net benefits to BC Hydro. Details of BC Hydro's evaluation were provided in Chapter 3 of the Phase One Application filed with the Utilities Commission December 21, 2016.

In the Phase One Decision, the BCUC determined that the work BC Hydro has done to identify and evaluate alternative supply chain applications is reasonable and the selection of an SAP-based system was justified.

Project Impacts & Benefits:

The annual recurring quantifiable benefits of the SCA Project at stabilization are expected to be $34.8 million, with $23 million of this amount monetized. Effort reduction benefits that are quantified but not monetized also have significant value. By redeploying saved time toward other higher-value activities, these effort reduction benefits can help manage increasing workload which may otherwise result in increasing headcount. Additionally there are significant non-quantified benefits, including the ability to close the capability gaps in BC Hydro's Supply Chain function and reduce the current risk profile. Further information on the project benefits and net present value analysis are included in Chapter 3 of the Phase Two Application.

Project Implementation Phase Risk:	**Risk Treatment:**
Scale of business process changes is too large to be absorbed successfully by BC Hydro	• Detailed change management plan. • Extended stabilization period and onboarding plan for implementation and benefits realization. • Strong governance and project management. • Detailed benefit realization plans.
Poor project management	• External quality assurance advisor. • Strong project governance. • Strong project management procedures from the System Integrator.
Poor quality of delivery by systems integrator	• Establish a strong contract with incentives for good quality delivery. • Strong project and contract management. • Robust quality management plan.
Low data quality and or data not being ready according to Project Schedule	• Continue detailed assessment and planning of data conversion requirements in early realization. • Alignment of the data conversion tasks with business transition and resource plans.

Additional Information:

The Phase Two Application relating to the Supply Chain Applications Project was filed with the Utilities Commission on October 12, 2018. The Phase Two Application included a Forecast Capital Cost of $68.0 million based on a Total Expected Capital Cost Estimate of $61.1 million and a Total Capital Project Reserve of $6.9 million. The Authorized Cost estimate (Authorized Cost) is $79.3 million, including capital and operating costs.

<table>
<tr><td>Investment Planning ID:
P201703</td><td colspan="2">Project Name:
Chilliwack Field Building Redevelopment</td></tr>
<tr><td>Forecast Capital Cost:
$32.0 million</td><td>Forecast In-Service Date:
Fiscal 2021</td><td>Start Date of Construction:[1]
Fiscal 2019</td></tr>
<tr><td>Development Phase:
Definition</td><td colspan="2">Filing Reference:
F17-F19 RRA:
• Appendix I, line 15, Appendix J, pages 84-85
• BCUC IRs 1.70.3, 1.116.1, 1.116.2, 1.116.3, 1.116.4, 1.116.5, 2.249.8, 2.260.4, 2.270.1,
BCOAPO IRs 1.36.1, 2.77.1</td></tr>
<tr><td colspan="3">Description:
This project involves the redevelopment of a regional field office located in Chilliwack.</td></tr>
<tr><td colspan="3">Key Drivers:
• Operational Requirements
• Safety
• Reliability</td></tr>
<tr><td colspan="3">Issues Being Addressed:
BC Hydro operations in the Chilliwack area are based at two locations, Chilliwack and Atchelitz. The existing Chilliwack facility is a leased property within a multi-tenanted facility, consisting of approximately 12,000 ft2 of office and warehouse space at 44550 South Sumas Road. The Atchelitz facility is owned by BC Hydro and was built approximately 40 years ago, and comprises about 5,500 ft2 of office space. It is located at 6155 Lickman Rd in Chilliwack, within the Atchelitz substation property boundaries. A total of approximately 35 staff are based at these two sites.
There is a long-term need for a suitable field office to provide post-disaster recovery and emergency operational support and to meet the needs of the almost 100,000 residents served in Chilliwack and the surrounding areas of Atchelitz, Cultus Lake, Sardis, Promontory Heights, Vedder, Yarrow, and Greendale. This includes appropriate outage response, planning and execution of the electric system to support local/regional development, and maintenance and upgrades to infrastructure to ensure ongoing system reliability in the region. The facilities must remain operational to support 24/7 emergency response in the worst weather conditions and in the event of a natural disaster. The Eastern Fraser Valley is continuing to grow at a fast pace. The population of Chilliwack increased 8.6 per cent between 2011 and 2016, and is expected to continue to grow at a similar rate over the next five to 10 years.
The existing facilities have been prioritized for redevelopment due to: the lack of adequate space for current and projected business operations; the inability to expand either the Chilliwack facility, as it is leased, or the Atchelitz location, as it is in close proximity to a substation; as well as the condition and associated seismic concerns of the existing buildings. The key issues are that the facilities:
• Have inadequate space for existing staff and materials, requiring some staff to work out of the Abbotsford facility, approximately 35 km away, and requiring the Abbotsford office to store a large volume of materials, including poles and transformers, for the Chilliwack/Atchelitz operations. This can delay response time, especially in the winter or during emergencies;
• Are inadequate for working, maneuvering and loading line trucks. The location of the Atchelitz office on the same site as a substation prevents office expansion and puts a strain on the safe and efficient use of yard space. It is also difficult to safely move and load line vehicles in the multi-tenanted Chilliwack office complex;
• Are both located in a high seismic region and do not meet requirements for a facility that is expected</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

to be fully functional in a post-disaster situation;

- Have inadequate fire suppression and sprinklers, contain hazardous materials; lack an emergency generator; require the replacement of the Atchelitz end of life roof; and
- Have inadequate office space to support the current and future demands.

Discussion of Alternatives:

The following six alternatives were considered in the Identification phase:

i. **Do nothing:** continue with existing facilities;
ii. **Lease** additional space in the existing Chilliwack facility;
iii. **Renovate and expand** the existing Atchelitz facility, or build new, and maintain the leased Chilliwack facility;
iv. **Construct** a new facility at a new BC Hydro owned location;
v. **Acquire** a new site and construct a new facility; and
vi. **Lease** a new larger facility, long-term.

Alternative v, Acquire a new site and construct a new facility, was selected as the recommended alternative as it best meets the current and anticipated future needs for servicing the Chilliwack region.

Project Impacts and Benefits:

- Project will result in new facility that meets current and anticipated functional and operational needs.
- The new facility will meet all current building codes including post-disaster standards.

Project Implementation Phase Risk:	Risk Treatment:
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	To be determined when the project reaches Implementation

Additional Information:

The Chilliwack Field Building was identified in the Previous Application as one of the high priority sites requiring work during the test period. At the time of the Previous Application, the scope of the project was under development.

Investment Planning ID: P201704	**Project Name:** Material Classification Facility Building Redevelopment	
Forecast Capital Cost: $42.4 million	**Forecast In-Service Date:** Fiscal 2022	**Start Date of Construction:**[1] Fiscal 2019
Development Phase: Definition	**Filing Reference:** F17-F19 RRA: • Appendix I, line 11, Appendix J, pages 82-83 • BCUC IRs 1.70.3, 1.117.1, 1.117.2, 1.117.3, 1.117.4, 1.117.5, 1.117.6, 2.249.8, 2.260.4, 2.270.1, 2.271.1, 2.271.2, BCOAPO IRs 1.36.1, 1.64.5, 2.77.1, CECBC IR 1.72.3.2	

Description:

This project involves the redevelopment of the Material Classification Facility located in Surrey.

Key Drivers:

- Environmental
- Operational Requirements
- Safety

Issues Being Addressed:

The Material Classification Facility is located at 12345 88th Avenue in Surrey, BC on the BC Hydro Surrey campus. The facility comprises the Transformer Shop and Hazardous Waste Operations including salvage and disposal operations and occupies an area of 19,766 ft2 of building area and 8.6 acres of yard space. The buildings were constructed throughout the 1970's and 1980's as business needs required. Approximately 27 employees work out of this facility.

The facility receives recovered electrical equipment and hazardous wastes from BC Hydro's facilities from across the entire province, making it critical in supporting other business units' waste needs. The products are received, drained of any oils, sorted, stored, and packaged or re-packaged prior to being transported offsite for recycling, treatment, or disposal at authorized hazardous waste management facilities.

The Material Classification Facility has been identified as a priority for redevelopment due to the environmental regulation requirements, zoning non-compliance, operational challenges, building conditions, and code compliance.

The key issues are that the facilities:

- Will need to meet the Ministry of Environment's requirements that BC Hydro will implement further environmental protection measures to prevent the release of contaminants of concern and prevent pollution;
- Contravene existing zoning regulations from the City of Surrey;
- Do not provide sufficient enclosed areas to sort and store materials;
- Cannot support current business requirements of oil storage and Paper Insulated Lead Covered cable sampling;
- Do not meet current building code standards, including being located in a high seismic region and meeting less than 50 per cent of the BC Building Code minimum requirements for normal buildings being able to withstand a seismic event; and
- Have numerous building components (building envelope, mechanical and electrical systems) at the end of their useful life and needing replacement.

The environmental regulations, functional limitations, and code issues negatively impact the ability of

[1] Start Date of Construction is the Implementation Approval Date.

staff to perform their duties and support BC Hydro operations from the Material Classification Facility.

Discussion of Alternatives:

The following five alternatives were considered in the Identification phase:

i. **Do nothing:** continue with existing facilities;

ii. **Apply for rezoning and, if approved, renovate** and expand the existing facilities to meet current building code, safety and program requirements;

iii. **Apply for rezoning and, if approved, construct** a new facility on the existing site and demolish the existing building;

iv. **Construct** a new facility at a new location on Surrey campus; and

v. **Acquire** a new site off the Surrey campus and construct a new facility.

Alternative iv, Construct a new facility at a new location on Surrey campus, was selected as the recommended alternative as it is the most cost effective alternative that meets the environmental, operational, and zoning requirements.

Project Impacts and Benefits:

- Project will result in a new facility being compliant with Ministry of Environment's Hazardous Waste Regulations.
- Project will reduce the risk of the release of contaminants of concern and prevent pollution.
- Project will result in a new facility being compliant with City of Surrey zoning regulations.
- Project will result in a new facility that meets operational needs and current building codes.

Project Implementation Phase Risk:	**Risk Treatment:**
Risks are identified starting in the Identification Phase and finalized in the Implementation Phase	To be determined when the project reaches Implementation

Additional Information:

The Materials Classification Facility was identified in the Previous Application as one of the high priority sites requiring work during the test period. At the time of the Previous Application, the scope of the project was under development.

The Fiscal 2017 to Fiscal 2019 Revenue Requirements Application identified a possible linkage between this project and the Construction Services/Lower Mainland Transmission Building Redevelopment project. At the time, we had anticipated submitting a section 44.2 application for the two projects, given their combined capital cost. Subsequently, the Construction Services/Lower Mainland Transmission Building Redevelopment project was deferred due to funding constraints, which is discussed further in Chapter 6, section 6.6.4. A project or projects to address the requirements for the Construction Services group and the Lower Mainland Transmission group will be revisited at a future date after the current test period. As a result, the Materials Classification Facility project is proceeding without any direct linkage to the project(s) to address the Construction Services and Lower Mainland Transmission requirements, and therefore a section 44.2 application for the Materials Classification Facility is not contemplated, as the capital cost for this individual project is anticipated to be below the $50 million threshold where BC Hydro would file a building project application.

<table>
<tr><td>Investment Planning ID:
P201901</td><td colspan="2">Project Name:
Kamloops Field Building Redevelopment</td></tr>
<tr><td>Forecast Capital Cost:
TBD</td><td>Forecast In-Service Date:
TBD</td><td>Start Date of Construction:[1]
TBD</td></tr>
<tr><td>Development Phase:
Future</td><td colspan="2">Filing Reference:
New</td></tr>
<tr><td colspan="3">Description:
This project involves the redevelopment of the high criticality large regional field office located in Kamloops.</td></tr>
<tr><td colspan="3">Key Drivers:
• Operational Requirements,
• Safety</td></tr>
<tr><td colspan="3">Issues Being Addressed:
The Kamloops District Office is located at 1155 McGill Road in Kamloops and was constructed in 1981. The District Office is approximately 34,000 ft2 in size and serves BC Hydro customers in Kamloops and the surrounding areas. The facility currently accommodates approximately 130 staff.
There is a long-term need for a suitable field office to provide post disaster recovery and emergency operational support and to meet the needs of more than 100,000 customers in the surrounding area that spans east to Chase, west to Savona, north to Barierre, and south to Lac Le Jeune. This support includes outage response, planning and execution of the electric system to support local/regional development, and maintenance and upgrades to infrastructure to ensure ongoing system reliability in the region. The facilities must remain operational to support 24/7 emergency response in the worst weather conditions and in the event of a natural disaster.
The existing facility has been prioritized for redevelopment due to a lack of adequate space for current and projected business operations, requirement for seismic and safety upgrades, and to address building condition and code compliance. The key issues are that the facility:
• Does not meet current functional and operational needs, with no room for potential growth, i.e. does not provide sufficient space to accommodate all current staff; does not provide adequate truck bays for truck storage or for Fleet’s current needs; and does not provide sufficient yard space for vehicles and materials;
• Is almost 40-years old, and does not meet current building code standards, including being less than 50 per cent of the BC Building Code minimum requirements for a post disaster resistance building;
• Has inadequate fire protection and accessibility, including non-conforming fire separation between the garage and offices;
• Has inadequate office space to support the current and future demands; and
• Has numerous building components (mechanical, electrical, HVAC, interiors) requiring replacement.</td></tr>
<tr><td colspan="3">Discussion of Alternatives:
Alternatives to be considered in the Identification Phase will include: renovate and expand the existing facility, construct a new facility on the existing site, and build a new facility on a new purchased or leased site.</td></tr>
<tr><td colspan="3">Project Impacts and Benefits:
To be determined when project reaches Definition Phase.</td></tr>
</table>

[1] Start Date of Construction is the Implementation Approval Date.

Project Implementation Phase Risk: Risks are identified starting in the Identification Phase and finalized in the Implementation Phase.	**Risk Treatment:** To be determined when the project reaches Implementation
Additional Information: N/A	

Investment Planning ID: **1115778**	**Project Name:** **Site C Project**	
Forecast Capital Cost: $9.297 Billion*	**Forecast In-Service Date:** November 2024**	**Start Date of Construction:**[1] July 2015
Development Phase: Implementation	**Filing Reference:** Amended F12-F14 RRA: • BCUC IRs 1.27.1 to 1.27.7, 1.108.1, 1.108.2, 1.139.2, 2.37.1 to 2.37.4, 2.78.2 F17-F19 RRA: • Appendix I, Appendix J, page 86 • BCUC IRs 1.5.1 Public, 1.11.1, 1.11.2, 1.32.4, 1.32.5, 1.32.8, 1.57.1, 1.57.5, 1.65.4, 1.70.3, 1.72.1,80.1, 1.80.3, 1.81.14, 1.99.1, 1.99.1.1, 1.99.2 – 1.99.5, 1.106.1-1.106.7, 1.124.11, 1.150.1, 1.182.1, 2.213.3.2, 2.216.2, 2.216.3, 2.222.2, 2.249.8, 2.260.4, 2.317.2, 2.318.1.1,4.5.1, 4.5.1.1, 4.5.1.2, 4.5.2, BCOAPO IRs 1.36.1,2.130.1, AMPC IRs 1.1.5, 1.1.7, 1.2.1, 1.4.8, 1.17.4, CEABC IRs 1.11.1, 1.13.1, 2.36.1, CECBC IRs 1.8.3, 1.8.5, 1.24.2, 1.27.1, 1.27.3, 1.68.3, 1.69.5, 1.70.1, 2.129.1, 2.129.1.1, Richard Landale IR 1.15.3, MoveUP IRs 1.4.1, 1.4.2, Skywind IRs 1.1.1, 2.6.4, Zone II Ratepayers IRs 1.1.1-1.1.8,1.5.2, 1.7.1-1.7.8., 1.7.8.1-1.7.8.4,1.7.9-1.7.11, 2.29.1, 2.30.1, 2.30.2	

Description:

Site C will be a third dam and hydroelectric generating station on the Peace River approximately seven kilometres southwest of Fort St. John. It will be capable of producing approximately 5,100 gigawatt-hours of electricity annually and 1,100 megawatts of capacity.

Key Drivers:

Generation Growth

Issues Being Addressed:

As the third project on one river system, Site C will gain significant efficiencies by taking advantage of water already stored in the Williston Reservoir. This means that Site C will generate approximately 35 per cent of the energy produced at W.A.C. Bennett Dam, with only 5 per cent of the reservoir area.

Discussion of Alternatives:

- Compared to other resource alternatives, Site C is an attractive resource option from the perspective of reliability and cost.
- Site C will be a clean and renewable source of firm electricity for over 100 years.
- Site C will produce among the lowest GHG emissions per GWh, when compared to other forms of electricity generation.

1 Start Date of Construction is the Implementation Approval Date.

Project Impacts and Benefits:

Project Benefits

New resources are required to meet long-term electricity needs in B.C. BC Hydro's long-term energy planning process has found that Site C provides the best combination of financial, technical, environmental and economic development attributes, compared to other electricity-generation options.

The Site C Project will provide key benefits for B.C., including energy, dependable capacity and flexibility, regional economic development, job creation, and benefits for communities and Aboriginal groups.

Project Attributes

- Site C will provide 1,100 megawatts of capacity, and produce about 5,100 gigawatt hours of electricity each year – enough energy to power the equivalent of about 450,000 homes per year in B.C.
- It will be a source of clean and renewable electricity for more than 100 years.
- Site C will have among the lowest GHG emissions, per gigawatt hour, compared to other resource options.
- As the third project on the Peace River, Site C will rely on the existing Williston Reservoir for water storage. This means Site C will generate approximately 35 per cent of the energy produced at the W.A.C. Bennett Dam, with only 5 per cent of the reservoir area.
- Site C will be among the most cost-effective resource options for BC Hydro ratepayers.
- Site C will create approximately 13,000 person-years of direct employment during construction.
- Construction will also provide significant opportunities for businesses of all sizes.
- Construction will contribute $3.2 billion to provincial GDP, including approximately $130 million to regional GDP.
- During construction, Site C will result in a total of $40 million in tax revenues to local governments and, once in operation, $2 million in revenue from grants-in-lieu and school taxes.
- Site C will be a source of affordable power to meet B.C.'s future electricity needs.

Environmental Assessment Process

The Site C Project received environmental approval from the federal and provincial governments in October 2014.

The approval of the project followed a cooperative federal-provincial environmental assessment process by the Canadian Environmental Assessment Agency (**CEA Agency**) and the British Columbia Environmental Assessment Office (**BCEAO**). The process started in August 2011 and took approximately three years to complete.

The environmental assessment process for Site C was thorough and independent and included multiple opportunities for timely and meaningful participation by the public, Aboriginal groups, all levels of government, and other interested stakeholders.

As part of the environmental assessment, BC Hydro undertook multi-year studies to identify and assess potential project effects and proposed comprehensive mitigation measures. All of this information was documented in more than 29,000 pages in the Site C Environmental Impact Statement (**EIS**) and associated documentation. The extensive review process included two months of public hearings in several regional and Aboriginal communities under an independent Joint Review Panel.

Community Benefits and Mitigation Measures

To date, BC Hydro has reached a regional legacy benefits agreement with the Peace River Regional District and community agreements with:

- District of Chetwynd
- District of Taylor
- City of Fort St. John
- District of Hudson's Hope

Among the benefits to local communities from the Site C Project are a regional legacy benefits agreement, infrastructure improvements, recreation and tourism opportunities, and affordable housing.

Project Implementation Phase Risk, Impact & Response Plan

Risk Category(s)	Risk Description	Impact and Response Plan Summary
Geotechnical Construction Execution	On the left bank diversion tunnels: Risk that contractor productivity does not meet plan and/or differing geotechnical conditions.	**Impact:** Potential schedule delay and increased cost. **Response:** Contractor has increased tunnel construction labour and equipment; contractor has improved work methods and/or additional subcontractors; BC Hydro has provided production incentives through settlement agreement with contractor.
Construction Execution	Risk that productivity for roller-compacted concrete is lower than planned.	**Impact:** Project schedule not achieved; potential interface issues may arise with other contractors. **Response:** Physical progress is captured and reported on a weekly basis for key work fronts. Key interface milestones are monitored and discussed on a regular basis. Meetings are held with the contractor on a regular basis.
Risk Category(s)	**Risk Description**	**Impact and Response Plan Summary**
Construction Cost – Labour	Risk that contractor labour rate increases in excess of budgeted amount.	**Impact:** BC Hydro has included provisions in the major contracts that allows for labour escalation to a prescribed amount, as well as a cost / savings sharing formula based on general industry rates above / below the prescribed amount. Increased pressure on the labour market would likely drive labour wage rates higher, potentially resulting in general industry increases beyond the prescribed amounts **Response:** BC Hydro has defined contract labour escalation formulas in all major contracts.
Safety	Risk of a safety incident resulting in fatality or disabling injury.	**Impact:** Serious worker injury or fatality; project delays and associated costs. **Response:** Implemented senior-level safety steering committee with all prime contractors to address shared safety issues and opportunities, hired permanent senior field safety manager, and holding regular on-site safety conferences.
Geotechnical Construction Execution	For work fronts other than the left bank diversion tunnel: Risk of differing geotechnical conditions.	**Impact:** Potential schedule delay and increased cost. **Response:** Completed detailed geotechnical investigations prior to construction; close monitoring and quick intervention to manage construction risk if geotechnical issues arise.
Litigation Indigenous Relations	Risk that Indigenous Nations do not support the project.	**Impact:** Indigenous Nation's file legal challenges (e.g., Injunction Applications) or engage in protest actions that could delay or stop the project work and/or increase costs. **Response:** Project team to fully support the development of legal response documents; follow court order requirements, if applicable; continue to negotiate Impact Benefit Agreements.

Construction Execution	Risk that reservoir clearing not completed for diversion.	**Impact:** Reservoir not cleared causing diversion delay; Outstanding 2018/19 seasonal work moved into next season (2019/20) using up float and increased cost to expedite. **Response:** Award Contracts at start of clearing season (November 2018); carry remaining work into 2019/20 season; hire additional contractors/resources for each clearing season.
Construction Execution	Risk that Highway 29 not completed on time for inundation.	**Impact:** Highway incomplete impacting inundation schedule; additional costs. Response: Increase design resources in peak periods; utilize schedule float; proactively respond to geotechnical issues; proponents to secure steel supply contracts during bid; use Ministry of Transportation Infrastructure specifications; support First Nations contractors to work with qualified builders.
Risk Category(s)	**Risk Description**	**Impact and Response Plan Summary**
Labour Relations and Stability	Risk that project cannot attract and retain sufficient skilled workers.	**Impact:** Contractors may not be able to adequately source, supply, attract, and retain sufficient project labour due to workforce demographics, increased competition for labour from other major projects, and the requirement for specialized workers. This may result in potential impacts to schedule, safety, productivity and cost. **Response:** Contractors provide labour sourcing and supply plans, provide advance notice of foreign workers, and participate in local job fairs. BC Hydro will encourage and facilitate capacity-building initiatives, monitor employee turnover rates and other projects labour conditions.
Foreign Exchange Rate, Interest and Taxes	Risk that BC Hydro's borrowing costs for project are higher than budgeted.	**Impact:** Rising interest rates increase the project's interest costs above the amount budgeted. Response: BC Hydro has hedged interest rates on approximately 50 per cent of future debt placements through fiscal 2024, to reduce the potential impact. The need for additional interest rates hedges is being assessed.

Additional Information:

The Site C Project received environmental approvals from the federal and provincial governments in October 2014. In December 2014, the project received approval from the provincial government to proceed to construction. In December 2017, the government decided to proceed with the Site C Project.

Project components include:

- Access roads and a temporary construction access bridge across the river at the dam site;
- A worker accommodation camp at the dam site;
- Upgrades to roads and realignment of segments of Highway 29;
- Two new 500 kV transmission lines connecting Site C to the existing Peace Canyon Substation, along an existing right-of-way;
- Shoreline protection at Hudson's Hope;
- An 800-metre roller-compacted concrete buttress to improve foundation stability and seismic protection;
- An earthfill dam, approximately 1,050 metres long and 60 metres high above the riverbed;

- A generating station with six 183 MW generating units, and spillways; and
- An 83-kilometre-long reservoir that would be, on average, two to three times the width of the current river.

*Total capital forecast cost presented excludes the Project Reserve of $708 million (established by Government to account for events outside of BC Hydro's control that could occur during construction) which is held by the Treasury Board. The approved total project costs (including Project Reserve, and Regulatory and Operating expenditures) is $10.7 billion

**Planned in-service date for the final unit. This timeline is subject to change based on reviews of the construction schedule.

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Appendix K

Summaries of Capital Project Strategies
Plans and Studies

Table of Contents

1 Introduction

This appendix includes summaries of Power System strategies, plans or studies that are linked to specific projects included in Appendix I[1]. Where applicable, the strategy, plan or study linked to a specific project has been identified in column W of Appendix I.

The summaries in this Appendix are consistent with the template provided in Appendix E of Exhibit B-7, filed by BC Hydro as part of the Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding.

This appendix is organized as follows:

- Section 2 provides an overview of the current state of BC Hydro's Power System;
- Section 3 explains BC Hydro's strategic planning process and the types of documents that are included in this appendix; and
- Attachment 1 provides summaries of 54 Power System strategies, plans and studies.

2 BC Hydro's Power System

2.1 Overall System

As described in Chapter 6, BC Hydro's generation, transmission and distribution systems form the Power System, generating electricity and delivering it to our customers throughout B.C. In December 2018, the Auditor General of British Columbia reviewed "whether BC Hydro is managing its assets well through appropriate information, practices, processes and systems. [The Auditor General]

[1] A Technology Strategy and Five-Year Plan is included as Appendix L. Specific strategies are not developed for the Properties, Fleet or Business Support/Other asset categories.

found that it is. BC Hydro has good asset management practices, not by accident, but as a result of a decade-long plan and associated efforts."

Through BC Hydro's capital investments over the last decade, system capacity has been increased, the effective life of several of the critical assets in the system has improved and many of the most critical Dam Safety risks have been mitigated.

BC Hydro continues to provide reliable, affordable, clean electricity throughout B.C. as a result of our asset management and capital investment strategies. As shown in section 6.3.2, BC Hydro's customer reliability, as measured by two industry-standard metrics, System Average Interruption Duration Index (**SAIDI**) and System Average Interruption Frequency Index (**SAIFI**), has performed consistently and BC Hydro's Customer Satisfaction Index indicate that customers continue to be satisfied with the level of reliability they are receiving.

Over time, the condition and performance of existing assets degrade, regulatory and safety requirements change and new assets are required to address load growth and connect new customers. Together, these factors create new issues, risks and opportunities to be addressed through continued maintenance and capital investment.

The following sections provide an overview of the current state of BC Hydro's Power System, with remaining issues, risks and opportunities highlighted. More detailed descriptions of the risks, issues and opportunities are discussed through the summaries of strategies, plans or studies in Attachment 1 of this appendix.

2.2 The Generation System

BC Hydro's generation assets include 83 generating units at 31 hydroelectric generating facilities as well as 81 dams located at generating stations and at additional locations to provide water storage and water diversion functions. Generation assets also include two storage dams, three gas-fired units at

BC Hydro's two thermal generating stations, and four synchronous condenser units at a dedicated synchronous condenser station. These facilities are categorized as "Key", "Strategic" or "Available" according to the significance of the facility to BC Hydro's system. BC Hydro has adopted life cycle asset management practices as its approach to managing generating assets. The objective is to maximize the economic return on physical assets over their life by achieving desired performance outcomes, while effectively managing the risks inherent in owning, managing and operating a large asset base.

2.2.1 Key Facilities

BC Hydro's seven "Key" generating facilities represent the largest hydroelectric facilities on the BC Hydro system and produce approximately 90 per cent of BC Hydro's average annual energy supply. In the past decade BC Hydro completed the installation of Unit 5 at Revelstoke and Units 5 and 6 at Mica generation stations which have added a total of 1500 MW of clean energy to the Power System. In addition, BC Hydro completed a number of sustaining investments to address end of life condition and reliability risks associated with critical equipment, including turbine overhauls and stator /exciter/ runner replacements.

In the coming years, BC Hydro will continue to focus on preserving reliability at the Key facilities, by directing investments towards mitigating the risks associated with the major equipment at these facilities currently rated as Poor and Unsatisfactory. Under this strategy, within 10 years all major equipment at Key facilities will have been, or will have work underway to be, restored to Good or Fair condition. The result of this is that, in aggregate, the reliability of Key facilities will be maintained at or slightly above the average of similar facilities, as reported by the Canadian Electricity Association.

The Bridge River facility contains 30 per cent of all Key facility equipment currently rated as Poor and Unsatisfactory. A number of capital projects are underway at

Bridge River, including the replacement of two of the eight generating units, which are anticipated to be in service in fiscal 2019. This will result in an improvement of asset condition at Key facilities.

The current state of the Key facility assets is also heavily influenced by a number of transformers at GM Shrum (**GMS**) that have been assessed as Poor, and issues with the stators at the Revelstoke facility (500 MW units). Plans are in place to address the deficiencies with the GMS transformers, and the risks with the Revelstoke stators are being addressed, with interim mitigating operating and maintenance strategies prior to proposed capital intervention.

2.2.2 Strategic Facilities

BC Hydro's 18 "Strategic" facilities represent all generating stations on Vancouver Island, all stations located on cascading systems, all thermal generation stations, and generating stations required to provide voltage support to the transmission network. These facilities produce approximately 9 per cent of BC Hydro's average annual energy and provide significant additional value to BC Hydro due to their geographic location and system support services.

In recent years there have been considerable investments in Strategic facilities. Overall, under BC Hydro's Capital Plan, the condition of Strategic hydroelectric facilities has improved. BC Hydro redeveloped the Ruskin and John Hart facilities, which went into service in fiscal 2018 and fiscal 2019, respectively. BC Hydro is restoring the health of the Cheakamus facility through investments in the generating equipment. With the completion of the generator replacement at Cheakamus expected shortly, this facility will see an improvement in its effective life.

Looking out over the next 10 years, equipment in Poor or Unsatisfactory condition at Strategic facilities will either be refurbished or replaced, will have work underway to be refurbished or replaced, or will have a long-term plan developed to mitigate the risk of equipment failure. Discrete investments are being made at Strategic facilities (including thermal generating facilities) to address the highest risks. However, a number of the smaller strategic facilities (e.g., Clowhom and Ash River) will receive limited investment and may experience extended forced outages, or be forced out of service prior to reinvestment. This strategy means that, in aggregate, the reliability of Strategic facilities will be maintained at or restored to the average of similar facilities, as reported by the Canadian Electricity Association.

2.2.3 Available Facilities

BC Hydro's seven "Available" facilities represent those facilities that are of lower strategic importance and produce less than 1 per cent of BC Hydro's average annual energy. 24 per cent of the assets at Available facilities (excluding Elko which is currently out of service) are rated as Poor and Unsatisfactory. The worst assets are located at the four smallest and oldest of these facilities (Shuswap, Elko, Falls River and Spillimacheen). The Elko facility (12 MW) and one of the units at Shuswap (3 MW) are out of service. Based on the current plan, these facilities will not be restored in the next 10 years. BC Hydro expects to continue to provide reliable electricity service to customers with these small facilities out of service.

Overall, Available facilities will receive minimal capital investment and will be taken out of service when they are no longer able to safely generate electricity. BC Hydro will perform regular maintenance and inspection on these assets to keep them safe and inform investment and operating decisions. Options to re-furbish, redevelop or decommission Available facilities that have been taken out of service will be developed as required. There is a high likelihood that a number of these facilities will experience long outages, or be forced out of service over the next 10 years. Over time, this strategy may result in a gradual reduction of the energy produced by Available facilities. However, in the long term this strategy will be revisited if the energy and capacity from these facilities is required, in light of their small contribution.

2.2.4 Dam Safety

BC Hydro operates 81 dams at 43 different sites. Safe operation of a dam considers more than just the physical structure that retains water within the reservoir; it also considers:

- The structures and devices that control and convey water over, through or around the dam leading up to or around the generating station, e.g., spillways, tunnels, penstocks, and gates and valves;
- The natural structures, slopes and barriers that support the dam and surround the reservoir; and
- The supporting infrastructure and instrumentation required to monitor and maintain these various constructed and natural features.

In managing its dams BC Hydro monitors, maintains and, as necessary and practicable, upgrades all of these structures and devices, natural features and supporting infrastructure. A recent audit of BC Hydro’s Dam Safety Program found that “BC Hydro has a well-established Dam Safety Program that is in line with international practices with some aspects operating at best practice levels” and that “BC Hydro continues to be a leader in risk assessment in the international dam safety community with a transparent, systematic and robust risk assessment process.”

BC Hydro’s dams are diverse in character. They range in size from a few very small dams that are upstream of no or only a few persons, to some of the largest dams in the world with that are upstream of several thousands of persons. These dams are classified by the potential consequences of their failure in accordance with the BC Dam Safety Regulation. Of BC Hydro’s 81 regulated dams:

- 28 are classified as being of Extreme consequence;
- Eight are classified as being of Very High Consequence;
- 15 are classified as being of High Consequence;
- 21 are classified as being of Significant Consequence; and
- Nine are classified as being of Low Consequence.

BC Hydro's dams vary in age from just over 10 years old to over 100 years old, with most being between 40 and 70 years old. The dams are situated in a demanding environment, frequently being stressed by extremes in temperature and high inflows. This leads to continuing and expected deterioration of the structures, in particular the spillways requiring ongoing maintenance and occasional capital investments to extend their service lives.

The dams' age also contributes to a state where some equipment is at its end-of-life or where design approaches in use at the time of their construction are no longer considered to be adequate. This is particularly true when it comes to the operational reliability of spillway gates and other flow control equipment, which presents a risk of malfunction that could lead to gates or valves failing to open when needed to route flood inflows or misoperation that could cause sudden changes in downstream flows and endanger the public. BC Hydro actively manages this risk through its continuing program to upgrade and rehabilitate its spillway gates systems.

BC Hydro's dams are located in a part of the world that is subject to natural hazards such as earthquakes and landslides. In response, BC Hydro has developed an industry-leading model to calculate seismic hazards at its dam sites and inform the needs and criteria for seismic upgrades. BC Hydro also maintains a program to monitor the slopes along its reservoirs, which includes instrumentation and drainage infrastructure in some slopes of key interest. Investments are regularly required to replace or remediate this instrumentation and drainage as it ages and loses effectiveness.

BC Hydro has made significant investments in safety upgrades to its dams since 2005, including:

- Approximately $400 million on upgrades to spillway gates systems at various dams;
- Over $200 million in upgrades to Ruskin Dam to address seismic and seepage deficiencies, to increase its flood discharge capacity and to replace its spillway gates systems;
- $120 million to replace the deteriorated rip rap on the upstream face of W.A.C. Bennett Dam;
- $65 million to rebuild Coquitlam Dam; and
- $55 million to perform upgrades to the spillway structure at W.A.C. Bennett Dam and stabilize the rock slope above it.

These investments were prioritized to address the biggest identified risks related to BC Hydro’s dams. Many other, smaller-scale investments in upgrades to the dams and their infrastructure, such as monitoring instrumentation, have also been made in recent years.

Overall, BC Hydro aims to improve or at least maintain the current level of risk across its entire fleet of dams, which we believe is well within the limits of what is considered to be tolerable. Our strategy considers the availability of the necessary expert engineering services (both internal and external) and experienced construction services, as well as our capacity to oversee this work. Our planned level of investment in dam upgrades is primarily driven by our ability to execute these upgrades effectively. On this basis, required investments in upgrades to

BC Hydro's dams have been prioritized over the coming decade and beyond. In the coming years, major investments in BC Hydro's dams will target the biggest current contributors to risk and will be made in the following areas:

- Major upgrades to improve seismic resistance, reservoir discharge capability and spillway gate reliability at the three main dams in the Campbell River system, namely John Hart Dam, Ladore Dam and Strathcona Dam;
- Continued upgrades to W.A.C. Bennett Dam to improve the operating reliability of its spillway gates systems, to decommission disused and deteriorating low level outlets and sluice gates—eliminating two potential weaknesses in the dam's water barrier—and the dam's network of monitoring instrumentation; and
- Improvements in the seismic resistance and operating reliability of the spillways and gates at and Mica Dam and Revelstoke Dam.

We are also just beginning to investigate conceptual alternatives to address deficiencies at La Joie Dam regarding its seismic resistance and excessive seepage that have led to an extended drawdown of its reservoir. Another notable, but smaller, project is being launched to remediate the rockfall hazard in the Terzaghi Dam spillway and provide for safe entry for inspections and repairs to that structure. Smaller investments will also be made to improve or replace dam infrastructure such as reservoir booms and miscellaneous instrumentation.

2.3 The Transmission and Distribution System

The overarching strategy for the Transmission and Distribution system is to maximize the long-term value of the system while minimizing the total life cycle costs of assets and ensuring safety and maintaining reliability. The strategy is accomplished by finding the optimal balance between efficiency, performance, cost, risk, security, regulatory requirements, and environmental and social aspects.

2.3.1 Transmission System

BC Hydro's bulk transmission system includes the 500 kV transmission system, parts of the 230 kV system, the transmission connections to Vancouver Island, and interconnections with other utilities through transmission interties. These lines connect the large remote generating stations in the Peace River and Columbia River areas with the major load centres of the Lower Mainland and Vancouver Island, which together represent over 70 per cent of the BC Hydro load.

Four regional transmission systems transfer energy within four specific geographic areas of the province: the Lower Mainland, Vancouver Island, Northern and the Southern Interior regions. The regional systems generally consist of 230 kV, 138 kV, and 60 kV transmission networks that connect local generation and deliver power to distribution utilities or transmission customers located within the region.

Long-term planning related to bulk and regional transmission needs are typically associated with moving energy over long distances. Long-term planning considers a wide range of supply-side and demand-side options, resulting in an integrated system plan. BC Hydro conducts assessments to evaluate the transfer capability of the system while still meeting North American Electric Reliability Corporation Transmission System Planning Performance and Western Electricity Coordinating Council requirements at all voltage levels. Investments are identified that are necessary to fund transmission system capacity additions.

2.3.1.1 Lower Mainland and Vancouver Island

In the last decade BC Hydro has made significant investments to increase the capacity of the bulk transmission system including the Interior to Lower Mainland and Vancouver Island Transmission Reinforcement projects. These investments have enhanced BC Hydro's ability to continue to serve the electricity needs of our customers in the highest density areas of the province.

With the completion of the Interior to Lower Mainland transmission line, installation of Mica Units 5 and 6 and the third transformer at the Meridian substation, the natural gas fired, peak generation capability from the Burrard Generating Station is no longer required to meet critical loads in the Lower Mainland. Accordingly, Burrard is instead being operated to provide voltage support for the transmission system in the Lower Mainland, using its capability to operate in synchronous condense mode. The four Burrard Synchronous Condenser units are now reaching end of life and are expected to experience reliability issues within the short to medium term. The near term focus of capital investment in the Lower Mainland transmission system will be to maintain BC Hydro's Lower Mainland bulk transmission system reliability during heavy winter load periods under single contingency conditions.

Ensuring the reliability of service in the region also requires addressing reliability risks associated with the end of life condition of 230 kV high voltage cables in the short term. These include the cable between Horsey substation (**HSY**) and Goward substation (**GOW**) in Victoria, as well as the segment of 138kV cable that supplies the Gulf Islands from Vancouver Island.

2.3.1.2 Northern Region

In recent years, BC Hydro has made significant investments in the northern region of the province, with projects such as the 230 kV Dawson Creek Area Transmission line and the 287 kV Northwest Transmission Lines projects, which provide regional transmission reinforcement to serve the growing regional load requirements.

In the next decade, BC Hydro will continue to invest in the Northern transmission system to address load and system growth requirements driven primarily by the development in the Oil and Gas sector in the Peace and North Coast regions. Investments will include completing the 230 kV Peace Region Electric Supply project, reinforcing the 500 kV Peace to Kelly Lake corridor to increase its transfer capability to the Lower Mainland, and interconnecting major industrial customer loads in this region.

Due to the continued economic activities expected in the Liquefied Natural Gas and Oil and Gas sectors, there are potentially significant additional upgrades to the transmission system in the North Coast and Peace region that may be required in the short to medium term which are not included in BC Hydro's Capital Plan. BC Hydro will work with customers in the area to define the need and scope of future projects. Projects will proceed once there is a formal commitment from potential customers. Expanding the capacity of the electricity supply in this region of the province will enable BC Hydro to supply reliable power to our industrial customers and help reduce greenhouse gas emissions by enabling customers to use clean electricity rather than fossil fuels to power their operations.

BC Hydro will also be investing to improve customer reliability in the region through investments such as the 5L63 Telkwa Relocation project, which will relocate a segment of the radial line that serves customers on the north coast and is currently situated in an active landslide area.

2.3.1.3 Southern Interior Region

BC Hydro recently completed the Merritt Area Transmission project to meet the increased demand for power in the Merritt area. BC Hydro is continuing to invest in the transmission system in the Southern Interior region of the province to provide reliable service to our customers. However, we are not expecting any major investments to serve load growth in the medium to long term as there is sufficient capacity to meet the load forecast in this region.

2.3.2 The Regional Substation and Distribution System

BC Hydro has four regional systems (the Lower Mainland; the Northern Interior; the Southern Interior; and Vancouver Island) which connect the transmission system to the local distribution systems. The substation and distribution network are made up of over 300 stations and 68,000 kilometres of distribution circuits in order to serve customers throughout the province.

In the past decade, BC Hydro has built 28 new substations within these regions, including 12 distribution substations enabling BC Hydro to supply more than 900 MVA additional load at distribution voltages. The most significant investments have been in the Lower Mainland and on Vancouver Island. Projects have included building an indoor 230/12 kV substation in the Mt. Pleasant area of Vancouver and two new underground 230 kV transmission lines connecting the new substation, as well as two new substations in the Courtenay and Nanaimo areas of Vancouver Island. In addition to the increased capacity, these new substations have improved the operational flexibility of the system. In some cases, the addition of new substations has facilitated the load transfer from other substations that were reaching end of life or ultimate capacity. This approach helps BC Hydro minimize the total cost of capital investment and maintenance over the life cycle of the substations.

We have also completed the Smart Metering and Infrastructure Program, which included the installation of 1.9 million smart meters in homes and businesses across the province. This provides an advanced telecommunications infrastructure to support electricity system management and customer applications, and information technology to support customer billing, load forecasting and outage management systems.

Our investments in the regional systems mean that BC Hydro's capacity to reliably serve the forecast load growth in many areas of the province has enhanced. Load growth in certain areas of the province, particularly the Fraser Valley, will require continued investment in new substation and distribution infrastructure to reliably supply customers.

BC Hydro will continue to mitigate end-of-life, safety and environmental risks by investing in new substations, such as the new West End Substation in downtown Vancouver. This new substation will enable the load transfer from Dal Graur (**DGR**) and Murrin (**MUR**) substations, which have reached end of life, and have many risks including safety and seismic. For other existing stations, such as Mainwaring in South Vancouver, our current strategy is to replace assets on a component by component basis as needed, considering factors such as condition, rate of deterioration, the operating environment, and criticality. One of the key considerations in determining the timing and strategy of investments is the requirement to replace equipment with polychlorinated biphenyl (**PCB**) levels at or above 50 ppm by the December 31, 2025 Federal Regulation deadline.

3 BC Hydro's Strategies, Plans and Studies

As part of its planning practices, BC Hydro identifies investments required on the Power System by evaluating the issues, risks and opportunities related to Power System assets. Long term planning information is captured in planning documents such as strategies, plans and studies. For the Power System, documents such as these help BC Hydro to assess system needs and develop solutions based on a region or area, river system, a facility or group of facilities, and asset classes. These planning documents provide context with respect to the rationale for investments that are either underway, or planned to start in the future. However, changing underlying factors, such as adjustments to load growth forecasts, resource or financial constraints, and new information and priorities can change the original scope of projects or solutions proposed in these planning documents. This means that while the planning documents capture the essence of the approach, the plans and investments proposed may change in response to new information. These changes will be reflected in the planning documents during the next update of the strategy, plan or study.

The process through which Power System strategies, plans and studies are developed is explained in detail as part of the bottom-up planning process descriptions included in section 6.4.2 (Generation) and section 6.4.4 (Transmission & Distribution).

Where applicable the strategy, plan, or study for the investments listed in Appendix I has been identified in column W. Not all projects in the Capital Plan may be related to an underlying strategy, plan or study. A summary of the identified strategies, plans and studies are provided in this appendix, following the example provided in Appendix E of Exhibit B-7. These documents can cover a period of up to 30 years or longer in some cases. Within each of the summaries in this appendix, the following principles were applied for identifying investments within the Short, Medium and Long Term time frames:

- **Short-Term:** Investments with expenditures within the fiscal 2020 to fiscal 2021 test period are defined in the Short-Term Solution;
- **Medium-Term:** Investments with expenditures anticipated to start within the next 10 years, but after the fiscal 2020 to fiscal 2021 test period are outlined in the Medium-Term Solution; and
- **Long-Term:** Investments with potential expenditures beyond the next 10 years are summarized in the Long-Term Solution.

The summaries within this appendix generally belong to one of the following five categories:

1. **Generation Facility Asset Plans:** Generation facility asset plans summarize the issues, risks and opportunities faced by a specific facility and outline the proposed long-term investment strategy that is believed to offer the best value at a specific time. Facility Asset Plans are key inputs to the fleet planning process. The investment strategies that are proposed in discrete facility asset

plans are reviewed collectively, and prioritized to provide the most appropriate suite of investments across the fleet given resource and financial constraints, outage planning, and other considerations;

2. **Dam Safety System Studies:** These studies are initiated to identify options that would permit the optimal risk management and investment strategy for the system using a Systems Engineering approach. A Systems Engineering approach provides a framework to manage complexities within the constraints of the river system to ensure technical coordination across a broad range of disciplines;

3. **Transmission and Distribution Asset Strategies:** BC Hydro has documented Asset Strategies for most of its Transmission and Distribution asset classes. These Asset Strategies provide a fleet approach to the management of each asset class across the entire system, and over their entire asset lifecycle;

4. **Transmission and Distribution Substation Asset Plans:** These plans are developed when a substation requires major investments to address end-of-life and other sustaining needs. The longer term capacity needed at the substation is also integrated in Substation Asset Plans; or

5. **Transmission and Distribution Area Studies:** These area plans are typically prepared, or updated, when capacity additions are required in an area, which is defined by interoperability of the area assets. Other known needs in the area, including sustaining issues at the area's substations, are integrated in the Area Studies.

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Appendix K

Attachment 1

Power System Strategies, Plans and Studies

PUBLIC

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Ladore Spillway Seismic Upgrade	11	Page 15	Page 1
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Revelstoke Improve Left Bank Slope Stability	13	N/A	Page 35
Revelstoke Replace Downie Slide Instrumentation	14	N/A	Page 35
Strathcona Upgrade Discharge	15	Page 17	Page 1
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W.A.C. Bennett Dam Seal Low Level Outlets	17	Page 21	Page 13
Alouette - Environmental Flow Discharge Upgrade and LLO Sealing	18	N/A	Page 3
Hugh Keenleyside - Spillway and Low Level Outlets Concrete Upgrade	19	Page 23	Page 15
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Cross Reference Index for Appendices I, J and K			
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G.M. Shrum Replace Unit 1-5 Exciter Transformers	27	N/A	Page 13
Kootenay Canal Upgrade Unit Protection and Install Sequence of Events Recorder	28	N/A	Page 20
Mica Replace Fire Alarm System	29	N/A	Page 26
Mica Replace Units 1 to 4 Generator Transformers	30	Page 34	Page 26
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Name of Capital Strategy, Plan or Study:
Campbell River Systems Engineering Assessment

Summarize Issue:

The Campbell River hydroelectric system on Vancouver Island consists of three reservoirs and dams (Strathcona, Ladore and John Hart) which are close-coupled and in series on the Campbell River. All three facilities are categorized as Extreme Consequence per the BC Dam Safety Regulation. The Campbell River system is an important water resource that makes a major contribution to power generation on Vancouver Island, supports valuable fish habitats and spawning grounds and provides a wide range of community and recreational services in the area. The objective of the Campbell River System study was to identify the preferred risk management strategy for the Campbell River System in view of the potential for future redevelopment.

Previous investigations into dam safety deficiencies in the Campbell River system identified that:

- John Hart Dam and Strathcona Dam have wide-ranging seismic deficiencies. At Strathcona Dam these deficiencies are compounded by the seismically deficient powerhouse and generation water passage that runs beneath the dam;
- The spillway gates system at Ladore Dam has insufficient resistance to seismic loads; and
- The spillway gates systems at all three dams have operational reliability deficiencies.

Owing to their common period of original design and construction, the seismic deficiencies at these dams make all of them vulnerable to failure in an earthquake of intensity expected to occur, on average, once every 500 to 1000 years. Given that these are all Extreme consequence dams, current expectations – as outlined in the Canadian Dam Association's Dam Safety Guidelines – are that they should be able to withstand an earthquake of intensity expected to occur once every 10,000 years.

In 2009, knowing that significant reliability and dam safety investments on this system were going to be required, BC Hydro initiated a top-down Systems Engineering assessment that investigated the full range of options for the development of the river system in order to identify how investments should be prioritized to deliver safe and sustainable long-term management of the river system assets. The range of configurations was bounded at one end by full or partial decommissioning and at the other end by a complete re-configuration and redevelopment of the entire system.

Conceptual solutions included the following considerations:

- Least total risk (to people, property and the environment) configuration;
- Maximum peak demand availability; and
- Maximum total energy output per year.

The Campbell River Systems Engineering Assessment concluded that the river system should not be substantially reconfigured and confirmed that redevelopment of the generating capability at John Hart would be appropriate. It further concluded that improvements in seismic withstand and operational reliability of the flood discharge systems at all three main dams are required and, finally, that protection against flooding is best achieved through adequate storage upstream of Stathcona Dam.

Summarize Solution:

The Campbell River System Study (completed in 2012) prioritized and recommended sequencing of the capital projects by reviewing the relative costs of the projects vs the anticipated risk reductions. A preferred strategy for sequencing of the risk reductions was refined during development of the capital plan, considering technical resource availability along with our understanding of the precedent project timelines and numerous site and project timing and schedule requirements.

One of the projects considered within this strategy, the John Hart Generating Station Replacement, is now in service.

Short-Term:

A number of projects dealing with the highest priority dam safety issues and risks are already underway. These projects will address the inadequate seismic withstand of various components of John Hart and Ladore Dams and establish a deep drawdown capability at Strathcona Dam for post-earthquake response. These projects will also address reliability deficiencies in the three dams' spillway gates

systems. They are: • John Hart - Dam Seismic Upgrade; • Ladore - Spillway Seismic Upgrade; and • Strathcona - Upgrade Discharge.
Medium-Term: In the medium term, risks posed to Strathcona Dam by the inadequate seismic withstand of the generating station water passage under the dam and of the dam itself will be addressed in turn by decommissioning and redeveloping the existing generating station—including the water passage—and upgrading the dam. The Strathcona – Upgrade Discharge project must be completed before implementation of the following can commence. • Strathcona - Dam Improvements – New Powerhouse; and • Strathcona - Dam Improvements – Embankment Dam.

Name of Capital Strategy, Plan or Study:
Alouette Facility Asset Plan

Summarize Issue:

The single unit, 9 MW Alouette facility is located in the Fraser Valley and was commissioned in 1928. It forms part of the Stave River system, with Stave Falls and Ruskin facilities located downstream. It consists of the Alouette Lake Reservoir, Alouette Dam, Power Tunnel from Alouette Reservoir to Stave Lake Reservoir, and Alouette Generating Station. Alouette is a Strategic facility for asset management purposes and Alouette Dam is an Extreme consequence dam per the BC Dam Safety Regulation. The original dam was replaced in 1983 when the current earthfill dam was constructed immediately downstream of the original dam. Alouette Generating Station has been out of service since 2010, due to condition and reliability issues with the majority of the generating equipment; however, the water conveyance components of the facility remain an important mechanism for conveying water to the Stave Falls and Ruskin facilities.

Although Alouette Generating Station is currently out of service, investments are being made to ensure safety, water conveyance, and environmental risks are mitigated. BC Hydro has invested over $5 million over the past 10 years. These investments include safety upgrades, and operating gate and trashrack replacements. The most significant remaining issues and risks associated with the Alouette facility include:

- Dam Safety:
  - Potential damage to the dam’s spillway in a major earthquake expected to occur once every 1,000 to 2,500 years that would render it unsafe for spills or drawdowns after the earthquake;
  - Potential failure of the dam’s right abutment foundation in a major earthquake expected to occur once every 2,500 years, which would lead to the eventual failure of the concrete weir structures that regulate flow over the spillway;
  - Expected failure of the power tunnel’s headworks and surge tower structures and ancillary equipment in an earthquake expected to occur once every 100 to 200 years, which could block the post-earthquake discharge of water from Alouette Reservoir to Stave Lake Reservoir; and
  - Potential rupture in a major earthquake of the seismically deficient low level outlet conduit (having unquantifiable withstand) that runs under the dam and provides environmental flows into the Alouette River downstream of the dam, which introduces the risk of internal erosion damage to the dam.

Summarize Solution:

The Alouette Facility Asset Plan presents short and long term investment strategies to mitigate risks related to dam safety, water conveyance, and the environment. In the short term, investments at Alouette will focus on addressing deficiencies related to post-earthquake discharge of the reservoir and associated risks posed to the dam by ensuring post-earthquake operability of the power tunnel leading from Alouette Lake Reservoir to Stave Lake Reservoir, and by constructing a new passage for passing environmental flows past the dam and down the Alouette River. The medium to longer-term focus will be to preserve the operational capability and infrastructure and, when appropriate, restore generation.

Short & Medium-Term:

- Dam Safety:
  - Headworks and Surge Tower Seismic Stability Improvement; and
  - Environmental Flow Discharge Upgrade and Low Level Outlet Sealing.

Long-Term:

- Generating Equipment:
  - Powerhouse Redevelopment.

The following are retained risks that are intended to be managed by completion of the Headworks and Surge Tower Seismic Stability Improvement project that is presently underway. These include:

- Seismic deficiency of the dam’s right abutment foundation and spillway weir; and

- Seismic deficiency of the dam's spillway.

On completion, this project will provide post-earthquake reservoir discharge into Stave Lake Reservoir via the power tunnel, thereby protecting these potentially damaged dam and spillway assets. Prior to the project's completion, Alouette Lake Reservoir will be operated in a manner that provides sufficient time to provide emergency response following a major earthquake.

Name of Capital Strategy, Plan or Study:
Ash River Facility Asset Plan

Summarize Issue:

The single unit, 28 MW Ash River facility is located on Vancouver Island and was commissioned in 1959. It consists of Elsie Lake Reservoir, Elsie Main Dam, four Saddle Dams, Elsie Spillway Dam, and Ash River Generating Station. Ash River is classified as a Strategic facility for asset management purposes and the dams are classified per BC Dam Safety Regulation as follows:

- Elsie Main Dam – Extreme consequence;
- Saddle Dam 1 – Extreme consequence;
- Saddle Dam 2 – Very High consequence;
- Saddle Dam 3 – Significant consequence;
- Saddle Dam 4 – Significant consequence; and
- Elsie Spillway Dam – High consequence.

Investments totaling over $5 million have been made to address safety and reliability concerns at the facility over the past 10 years. Completed capital investments have included upgrading the fire protection system, extending the life of the pressure regulating valve, improving security at Elsie Dam and upgrading the powerhouse crane.

The most significant remaining issues and risks associated with the Ash River facility include:

- Generating Equipment:
  - Unsatisfactory condition of the generator, elevating the reliability risks associated with the single unit and increasing the likelihood that the facility may experience an extended forced outage; and
  - Obsolete and deteriorating protection and controls and metering systems pose a reliability risk and could result in misoperation, equipment damage, and forced outages.
- Dam Safety:
  - The coatings on the steel penstock have failed which will lead to corrosion and metal loss of the underlying material, thereby reducing the life of the penstock. A finite window of opportunity exists to re-coat the assets before a much more extensive replacement / refurbishment is required; and
  - The ongoing deterioration and accelerated decay of the woodstave penstock is reducing its ability to continue to safely convey water which may prematurely impact ongoing generation from the facility.

Summarize Solution:

The Ash River Facility Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed) considering factors such as condition, rate of deterioration, the operating environment and criticality.

In the short term, activities to address the risks with the steel penstock, generator, and protection and control and metering systems will be undertaken in order to address reliability and power supply risks. In the medium-term, risks with the woodstave penstock will be mitigated. In the longer-term, work on other major unit components will be undertaken in order to mitigate reliability risks.

Short-Term:

- Generating Equipment:
  - Generator upgrade; and
  - Protection and control and metering systems upgrade.
- Dam Safety:
  - Steel penstock re-coat.

Medium-Term:

- Dam Safety:
  - Woodstave penstock replacement.

Long-Term:

- Generating Equipment:
  - Turbine overhaul;
  - Governor replacement.

Name of Capital Strategy, Plan or Study:
Bridge River Facility Asset Plan

Summarize Issue:

The eight-unit, 500 MW Bridge River facility is located approximately 60 km west of Lillooet and forms part of the Bridge River system with the La Joie facility and the Seton facility located upstream and downstream, respectively. The facility consists of:

- Carpenter Lake Reservoir;
- Terzaghi Dam, which was completed in 1960;
- The four-unit, 200 MW Bridge River 1 Generating Station, which was commissioned in 1954; and
- The four-unit, 300 MW Bridge River 2 Generating Station, which was commissioned in 1960.

The Bridge River facility is classified as a Key facility for asset management purposes and Terzaghi Dam is classified as an Extreme consequence dam per the BC Dam Safety Regulation.

BC Hydro has made a number of investments in the Bridge River facility over the past 10 years, totaling over $100 million. Investments in the generating equipment have included: Bridge River 1 (**BR1**) Transformer replacements, BR1 Switchgear Replacement, BR1 Penstock Leak Detection, BR1 Powerhouse Piping Replacement, Bridge River 2 (**BR2**) Unit 7 and 8 Unit Circuit Breaker replacement and BR2 Penstock Inlet Valve Hydraulic Control Upgrade. Other key investments have included: the Bridge River Town Site redevelopment and reliability upgrades of the Terzaghi Dam Spillway Gates.

The overriding concern in the Bridge River System is that of water management and operating in accordance with the water licenses that have been issued to BC Hydro. The system is heavily constrained with limited allowable flows past Terzaghi Dam into the lower Bridge River. At present, the generating capacities of all four units at Bridge River 2 have been de-rated due to degrading equipment condition, reducing the flow of water that can be routed through that generating station and hindering BC Hydro’s ability to prevent excessive flows in the lower Bridge River. This is compounded by the fact that Downton Reservoir behind La Joie Dam at the upstream end of the system has been drawn down to manage dam safety risks at that facility, removing a portion of the system’s available storage buffer and flexibility. Restoring reliable generation to historic levels, at both the Bridge River 1 and Bridge River 2 generating stations, will enable more effective water management throughout the system, and also mitigate reliability risks associated with lost generation.

The most significant remaining issues and risks associated with the Bridge River facility include:

- Generating Equipment:
  - Poor and Unsatisfactory condition of the Bridge River 1 and Bridge River 2 generators, elevating the reliability and water management risks associated with the generating units and increasing the likelihood that the facility may experience an extended forced outage;
  - Poor condition of three Bridge River 2 circuit breakers, elevating the risk of forced outages;
  - Poor condition of two Bridge River 2 exciters and obsolescence of the Bridge River 1 exciters, elevating the risk of forced outages;
  - Poor condition of six of the Bridge River 1 and 2 Governors, elevating the risk of forced outages; and
  - Poor condition of two Bridge River 2 turbines, elevating the risk of forced outages.
- Dam Safety:
  - Failed coatings on the steel penstocks which will lead to corrosion and metal loss of the underlying material, thereby reducing the life of the penstocks. A finite window of opportunity exists to re-coat the assets before a much more extensive replacement or refurbishment is required.
  - Deficiencies in the seismic withstand and operational reliability of the low level outlet gates at Terzaghi Dam, which could result in their failure to open as needed in a flood event or following an earthquake, for which the risk is managed in part by regular testing and maintenance of the gate system;

- Deficiencies in the seismic withstand of the two intake towers on Carpenter Reservoir, which would likely be damaged in an earthquake somewhat smaller than that expected to occur once every 500 years, limiting or disrupting their ability to direct water to the Bridge River 1 and Bridge River 2 powerhouses for generation and managing the reservoir level;
- Stability of the Bridge River 1 penstock slope and powerhouse foundation, especially during an earthquake, comprising a risk that slope or powerhouse movement could cause a penstock rupture. Slope stability is a retained risk that is managed at the powerhouse with wells and sensors to control and monitor groundwater pressures and a leak/rupture detection system on the Bridge River 1 penstocks; and
- Rock fall hazard in the Terzaghi Dam spillway chute, due to which the spillway chute cannot be safely entered without significant preparatory work such as rock scaling and installation of protective structures. Lack of safe access to the spillway chute impedes the inspection, maintenance and assurance of safe condition of the spillway.

Summarize Solution:

The Bridge River Facility Asset Plan presents a strategy to replace assets on a component by component basis considering factors such as condition, rate of deterioration, the operating environment and criticality.

Investments requiring outages have been consolidated to reduce the impact on water management in the system. In the short term, the focus will be on higher priority investments required for water management and safe and reliable generation. The medium to longer-term activities will focus on the low level outlets at Terzaghi Dam and the penstocks at Bridge River 1.

Short-Term:

- Generating Equipment:
  - The units at Bridge River 2 are in relatively worse condition, and will be addressed first:
    - Units 5 & 6 require the most urgent attention – the project will address issues with the generators, governors, circuit breakers and exciters (the forecast in service date is fiscal 2020); and
    - Units 7 & 8 will be addressed next – the project will mitigate issues with the generators, circuit breakers and turbines.
  - Once the highest priority units have been addressed at the Bridge River 2 generating station, attention will turn to remediating risks with the remaining four units at Bridge River 1:
    - The project will address the issues with generators, exciters and governors on the four units. The worst of these is Unit 4, which will be prioritized first.
  - Completion of this work at the Bridge River 1 and Bridge River 2 generating stations will mean that the units are reliable, can run at historic levels and can be used as a reliable mechanism for conveying water.
- Dam Safety:
  - Bridge River 2 interior penstock recoating;
  - Bridge River 1 interior penstock recoating;
  - Bridge River 1 slope stability improvement;
  - Terzaghi Dam spillway chute safe access improvements; and
  - Bridge River 1 Mitigate Surge Spill Hazard.

Medium-Term:

- Dam Safety:
  - Bridge River 1 exterior penstock recoating; and
  - Terzaghi Dam low level outlet reliability improvements.

Long-Term:

- Generating Equipment:
  - Bridge River 1 and 2 major valve replacements.
- Dam Safety:
  - Bridge River 1 and 2 intake seismic stability improvements.

Name of Capital Strategy, Plan or Study:
Cheakamus Facility Asset Plan

Summarize Issue:

The two unit, 158 MW Cheakamus facility is located near Squamish and was commissioned in 1957. It consists of Daisy Lake Reservoir, Cheakamus Dam and Cheakamus Generating Station. Cheakamus is classified as a Strategic facility for asset management purposes and Cheakamus Dam is classified as an Extreme consequence dam per the BC Dam Safety Regulation.

BC Hydro has made substantial progress restoring the health of this generating facility over the past 10 years through a number of investments totaling over $100 million. Investments in the generating equipment have included the turbine runner upgrades, powerhouse crane refurbishment, sump controls upgrade, and an improvement of the plant's fire protection and security. Dam Safety investments have included spillway gate reliability improvements.

The most significant remaining issues and risks associated with the Cheakamus facility include:

- Generating Equipment:
  - Poor condition of the Unit 1 and Unit 2 generators which increases the reliability risk of the generating units and could result in an extended forced outage;
  - Failed interior and exterior coatings on Unit 1 and Unit 2 penstocks, which will lead to corrosion and metal loss of the underlying material thereby reducing the life of the penstock; and
  - Unsatisfactory condition of the Unit 1 and Unit 2 Turbine Inlet Valves which increases the operational risks associated with the generating units;
- Dam Safety:
  - Seepage and potential internal erosion of the dam at high reservoir levels which is currently mitigated by maintaining a reduced maximum reservoir elevation;
  - Insufficient resistance to seismic loads that may lead to failure of the dam, spillway, spillway gates and/or penstock pedestals in a major earthquake occurring, on average, about once every 1,000 years or more;
  - Residual deficiencies in the reliability of the upgraded spillway gates system, notably the lack of "black start" capability of the system's uninterruptible power supply (**UPS**) that would restore electrical power to the gates in the event of a local blackout. The risk of the gates failing to operate as required in such events is currently mitigated by maintaining and testing back-up diesel generators on site; and
  - Potential for a landslide at the Barrier and 4th Lobe slopes to impact the dam and downstream channel.

Summarize Solution:

The Cheakamus Facility Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. In the short-term, the focus will be on higher priority investments required for safe and reliable generation that are sequenced to minimize outages. The medium to longer-term activities will focus on the dam and spillway facilities.

Short-Term:

- Generating Equipment:
  - Units 1 and 2 generator replacement (planned In Service Date fiscal 2019);
  - Units 1 and 2 penstocks recoat (interior and exterior); and
  - Units 1 and 2 turbine inlet valves replacement.

Medium- and Long-Term:

- Dam Safety
  - Spillway seismic upgrade;
  - Dam seepage and seismic upgrade.
  - Penstock pedestals and slope improvement; and
  - Spillway gates reliability improvement.

The retained risk associated with a landslide at the Barrier and 4th Lobe slopes is managed by ongoing inspection and monitoring of the slopes.

Name of Capital Strategy, Plan or Study:
Duncan Dam Facility Asset Plan

Summarize Issue:

Duncan Dam is located immediately upstream of the confluence of the Duncan and Lardeau Rivers, and approximately 10 kilometers upstream of the North Arm of Kootenay Lake. Duncan Dam was commissioned in 1967 under the terms of the Columbia River Treaty to provide storage for flood control and to maximize hydro generation in both the United States and Canada. The facility includes Duncan Lake Reservoir and Duncan Dam. There is no generating station at this facility. Duncan Dam is classified as an Extreme consequence dam per the BC Dam Safety Regulation.

BC Hydro has made progress in restoring the health of this facility over the past 10 years through a number of Dam Safety investments totaling over $35 million, including the refurbishment of the low level outlet gates, targeted spillway gate system upgrades (not including the gates themselves), upgrades to dam instrumentation to measure seepage through the dam and foundations, and the installation of a steel sheet pile cutoff wall to upwardly extend a portion of the dam's core that was discovered to be 6 feet to 8 feet below its design elevation.

The most significant remaining Dam Safety issues and risks associated with the Duncan Dam facility include:

- Poor structural condition of the spillway gate bodies;
- Potential liquefaction of the dam's foundation in a major earthquake that would be expected to occur, on average, once every 3000 years, which could lead to large enough deformations for the dam to be overtopped;
- Deficiencies in the operational reliability of the reservoir discharge (spillway and low level outlets) systems that could result in their failure to open as needed during high inflows, for which the risk is managed by regular testing and maintenance of these systems; and
- Poor condition of the riprap on the dam's upstream face which could allow erosion of the dam's shell and a consequential failure of the dam's upstream slope, for which the risk is currently managed by semi-annual inspections and provision for localized repairs as need arises.

Summarize Solution:

The Duncan Dam Facility Asset Plan presents a strategy to mitigate risks related to safe storage and reliable passage of water under normal and unusual (e.g., flood and earthquake) conditions.

Short-Term:

- Spillway gates replacement.

Medium-Term:

- Seismic stability improvement; and
- Riprap replacement.

Long-Term:

- Discharge facilities reliability upgrade.

Name of Capital Strategy, Plan or Study:
G.M. Shrum Facility Asset Plan

Summarize Issue:

The 10-unit, 2,917 MW G.M. Shrum facility is located 23 km upstream of Peace Canyon Dam and approximately 160 km from the Alberta border. It was commissioned in stages from 1968 through 1980. It is comprised of the Williston Reservoir, W.A.C. Bennett Dam and the G.M. Shrum Generating Station. G.M. Shrum is classified as a Key facility for asset management purposes and W.A.C. Bennett Dam is classified as an Extreme consequence dam per the B.C Dam Safety Regulation.

BC Hydro has made substantial progress in maintaining and improving the health of this generating facility over the past ten years through a number of investments totaling about $750 million. Investments in the generating equipment have included replacement/refurbishment of many of the original key components, including units 1 to 5 turbine upgrade, units 1 to 4 stator replacement, increased capacity of units 6 to 8, three of four phases of transformer replacements, and station service replacement. Significant Dam Safety investments have included: stabilization of the rock slope above the dam's spillway, resurfacing and other upgrades to the concrete lining of the spillway chute, upgrades to the rip rap on the upstream face of the dam, and upgrades to the dam's core including rehabilitation of instrumentation wells.

The most significant remaining issues and risks associated with the G.M. Shrum facility include:

- Generating Equipment:
  - Poor condition of eight of the 30-unit transformers, combined with emerging deficiencies on some of the unit transformers, poses an operational reliability risk;
  - Poor condition of the unit 5 generator, elevating the reliability risks associated with the unit and increasing the likelihood of an extended forced outage;
  - Failed coatings of the intake operating gates and intake maintenance gates, which could lead to corrosion and metal loss of the underlying material, thereby reducing the life of the gates;
  - Deficiencies in the hydraulic systems of the intake operating gates that could result in operational reliability risks; and
  - Degrading condition of various coatings in the water passages, including penstocks, scroll case, and coupling chamber, which could lead to corrosion and metal loss of the underlying material, thereby reducing the life of the assets.
- Dam Safety:
  - Deficiencies in the operational reliability of the spillway gates that could result in their failure to operate as needed during high inflows, the risk of which is currently managed by regular testing and maintenance of the gates system;
  - Unknown but presumably deteriorating condition of now-disused low level outlets situated within the construction-period diversion tunnels, failure of which would lead to uncontrolled release of Williston Reservoir;
  - Deteriorating, non-functioning and disused sluice gates below the spillway gates, failure of which would lead to uncontrolled release of Williston Reservoir;
  - Continued erosion of the rock face above the spillway approach channel which is beginning to undermine the storage location of the spillway's maintenance stoplogs, the risk of which is managed by ongoing surveillance of the slope and progression of erosion; and
  - Presumed seismic deficiency of the spillway's structures and electrical and mechanical equipment (presently the subject of a Dam Safety Investigation).

Summarize Solution:

The G.M. Shrum Facility Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed) considering factors such as condition, rate of deterioration, the operating environment and criticality. In the short-term, projects are staged to prioritize investments in key generating equipment and high risk dam safety components. In the medium to long-term, projects are staged to address the next highest risks in the generating equipment, including upgrade of units 9 and 10, and improve reliability and seismic performance of the flood discharge system.

Short-Term:

- Generating Station:
  - Unit 5 stator replacement;
  - Unit 9 and Unit 10 circuit breaker replacement;
  - Transformer replacement (phase 4);
  - Pauwels transformer life extension;
  - Intake operating gate and intake maintenance gate refurbishment;
  - Intake operating gate hydraulic upgrade; and
  - Water passage refurbishment.
- Dam Safety:
  - Spillway gate reliability upgrade;
  - Sealing of the low level outlets; and
  - Recommissioning or sealing the spillway sluice gates.

Medium-Term:

- Generating Station:
  - Unit 9 and Unit 10 turbine overhaul; and
  - Unit 9 rewind stator.
- Dam Safety:
  - Spillway seismic upgrade; and
  - Spillway approach channel upgrade.

Long-Term:

- Generating Station:
  - Unit 7 and Unit 8 Stator Replacements.
- Dam Safety:
  - Spillway Gate Electrical and Mechanical Improvements.

Name of Capital Strategy, Plan or Study:
Hugh Keenleyside Facility Asset Plan

Summarize Issue:

The Hugh Keenleyside facility is located on the Columbia River, about 8 km upstream of Castlegar. Hugh Keenleyside Dam was commissioned in 1968 under the terms of the Columbia River Treaty to provide storage for flood control and to maximize hydro generation in both the United States and Canada. The major components of the Hugh Keenleyside facility include the Arrow Lakes Reservoir, Hugh Keenleyside Dam comprising an earthfill dam and a concrete gravity dam with spillway and low level outlets, and a Navigation Lock to provide a passage for commercial and recreational marine traffic through the dam. The Hugh Keenleyside facility does not have a generating station, but a power canal on the left abutment diverts water from the Arrow Lakes Reservoir to the Arrow Lakes Generating Station owned by Columbia Power and the Columbia Basin Trust. Hugh Keenleyside Dam is classified as an Extreme consequence dam per the BC Dam Safety Regulation.

BC Hydro has made substantial progress restoring the health of this facility over the past 10 years through a number of investments totaling over $100 million, including an upgrade of the navigation lock controls, a major spillway gate reliability upgrade, replacement of the debris boom, dam instrumentation improvements, and facility security system upgrade.

The most significant remaining issues and risks associated with the Hugh Keenleyside facility include:

- Dam Safety:
  - Spillway and low level outlet concrete erosion which, if not addressed, could impact the operation of the facility and the maintenance and inspection of the gates. There is also a risk that the eroded zones could grow in size during high water discharges, resulting in an extended outage of the spillway. These risks are currently managed by having implemented modified discharge operating procedures to slow the damage and by periodic underwater inspections;
  - Degrading condition of the foundation drains and instrumentation, where non-functioning drains would reduce the stability of the dam. This risk is managed by continuous monitoring of the uplift pressures under the dam and the condition of the instruments;
  - Potential post-earthquake deformation of the concrete spillway piers, which would render the Low Level Outlet Gates inoperable and limit the post-earthquake reservoir discharge capability; and
  - Moderately deficient seismic withstand of the earthfill dam relative to its Extreme consequence classification, estimated to be equivalent to an earthquake expected to occur once every 8,000 years.
- Facility Equipment:
  - Degrading condition of the coatings on the navigation lock gates, which will lead to corrosion and metal loss of the underlying material, thereby reducing the life of the asset; and
  - Deterioration of the service water piping.

Summarize Solution:

The Hugh Keenleyside Facility Asset Plan presents a strategy to mitigate risks related to safe storage and reliable passage of water under normal and unusual (e.g., flood and earthquake) conditions. The short-term investments include upgrading the concrete discharge structures to ensure continued safe and reliable water discharge, and preserving the critical navigation lock infrastructure. The medium term investments focus on addressing the seismic withstand deficiencies of the concrete dam (i.e., deformation of the spillway piers), upgrading the instrumentation and monitoring of water pressures under the dam, and enhancing the operability of the select components of the discharge system. The long-term investment focuses on addressing the seismic withstand deficiencies of the earthfill dam.

Short-Term:

- Dam Safety:

  Spillway and low level outlet concrete upgrade.

- Facility Equipment:
  - Service water piping replacement (planned In-service Date fiscal 2020); and
  - Navigation lock gates recoating.

Medium-Term:

- Dam Safety:
  - Concrete dam seismic stability upgrade;
  - Dam foundation drains and instrumentation replacement; and
  - Spillway and low level outlet stoplogs recoat.

Long-Term:

- Dam Safety:
  - Earthfill dam seismic stability upgrade.

Name of Capital Strategy, Plan or Study:
John Hart Facility Asset Plan

Summarize Issue:

The three unit, 135 MW John Hart facility is located on Vancouver Island and was originally constructed in 1947. John Hart forms part of the Campbell River system, with Ladore and Strathcona facilities located upstream. The facility includes the John Hart Reservoir, John Hart Dam, and the John Hart New Generating Station. The original John Hart Generating Station was developed in 1947 and permanently ceased operation when the John Hart New Generating Station was placed into service in 2018. John Hart is classified as a Strategic generating facility for asset management purposes and the John Hart Dam is classified as an Extreme consequence dam per BC Dam Safety Regulation.

The John Hart facility has received a significant level of investment in the last 10 years, with over $1 billion of investments made to construct a new power intake, power tunnel, underground generating station, and environmental flow bypass, as well as provide interim upgrades for the most pressing dam safety issues.

Prior to making this investment, in 2009, BC Hydro initiated the top-down Campbell River Systems Engineering Assessment. This study investigated the full range of options for the development of the river system to prioritize investments to safely and sustainably manage and operate the river system assets, with a particular focus on the risks associated with the system's seismic fragility and flow control deficiencies.

The most significant remaining issues and risks at the John Hart facility include:

- Dam Safety:
  - Susceptibility of the dam to fail in an earthquake expected to occur, on average, once every 500 years;
  - Deficiencies in the operational reliability and seismic withstand of the spillway gates system, for which the risk is currently managed by regular testing and maintenance of the system;
  - Potential for flow imbalance due to interruption of generation at John Hart while generation continues at Ladore Generating Station upstream, for which the risk has been partially addressed by improvements implemented within the generating station redevelopment with the residual risk being managed through controls to automatically shut down generation at Ladore in the event of a shutdown at John Hart; and
  - Unreliable water level gauges downstream of John Hart Dam.

Summarize Solution:

Following the recent redevelopment of the generating station, this facility's investment strategy exclusively targets the existing Dam Safety risks identified above. Capital upgrade projects are currently underway or scheduled to commence in the short-term to address these risks.

Short-Term:

- Dam Safety:
  - Upgrades to the John Hart Dam to address seismic, flow imbalance and spillway gate reliability issues; and
  - Upgrades to the Campbell River water level monitoring system.

Name of Capital Strategy, Plan or Study: **Jordan River Facility Asset Plan**

Summarize Issue:
The single unit, 167 MW Jordan River facility is located on the southern part of Vancouver island, approximately 40 km west of Sooke at the end of a radial transmission line. The facility was redeveloped in 1971. It consists of:
• Bear Creek Reservoir,
• Jordan Diversion Reservoir,
• Elliot Headpond,
• Bear Creek Dam,
• Jordan Diversion Dam,
• Elliot Dam, and
• Jordan River Generating Station.
Jordan River is classified as a Strategic facility for asset management purposes and the dams are classified per BC Dam Safety Regulation as follows:
• Elliott Dam- Very High consequence;
• Jordan Diversion Dam - Very High consequence;
• Bear Creek Dam - Low consequence.
In the past 10 years, Jordan River has benefited from a number of capital investments totaling approximately $25 million. Recent equipment investments have included: mitigating known safety and reliability risks related to the 13 kV circuit breakers, fire protection system upgrades and recoating the majority of the penstock. Other recent investments have included the acquisition of properties downstream of Jordan River. These acquisitions are part of the effort to reduce public exposure in downstream areas that could be in inundated in the event of a major earthquake.
The most significant remaining issues and risks associated with the Jordan River facility include:
• Generating Equipment:
  - Governor and pressure reducing valve obsolescence leading to system reliability and maintainability issues; and
  - Deteriorating condition of the powerhouse fire protection system which could lead to localized damage of the piping and a subsequent failure to operate normally when required.
• Dam Safety:
  - The coatings on a number of sections of the penstock have failed which will lead to corrosion and metal loss of the underlying material, thereby reducing the life of the penstock. A finite window of opportunity exists to re-coat the assets before a much more extensive replacement or refurbishment is required;
  - Safety risks associated with members of the public accessing the out-of-commission intake tower at Bear Creek Dam for recreational swimming activities;
  - Susceptibility of the Low consequence Bear Creek Dam to failure in a small to moderate earthquake;
  - Obstruction of the Bear Creek Spillway that can cause outflows to back up against the downstream “toe” of the dam and cause potential damage; and
  - Susceptibility of Jordan Diversion Dam and Elliott Dam to failure in an earthquake expected to occur, on average, approximately once in every 500 years, for which the risk is currently being managed as described above.

Summarize Solution:

The Jordan River Facility Asset Plan proposes a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed) considering factors such as condition, rate of deterioration, the operating environment and criticality.

In the short term, activities to address the risks with the governor, fire protection system, and the Bear Creek intake tower structure will be undertaken. In the medium to long term, activities will be started to address Bear Creek Dam and spillway pending the recommendations from a forthcoming strategic review of these assets. In the longer term, investments in the aging generating equipment as well as refurbishment of the Jordan Diversion Dam low level outlets may be required.

Short-Term:

- Generating Equipment:
  - Upgrade of the governor and pressure reducing valve system; and
  - Upgrades to the powerhouse fire protection system;
- Dam Safety:
  - Penstock recoating; and
  - Bear Creek Dam intake tower decommissioning.

Medium-Term:

- Dam Safety:
  - Potential upgrades to the Bear Creek spillway.

Long-Term:

- Generating Equipment:
  - Turbine overhaul;
  - Generator overhaul; and
  - Exciter upgrade.
- Dam Safety:
  - Jordan Diversion Dam low level outlets refurbishment; and
  - Potential seismic upgrade at Bear Creek Dam.

Name of Capital Strategy, Plan or Study:
Kootenay Canal Facility Asset Plan

Summarize Issue:

The four unit, 580 MW Kootenay Canal facility is located on the Kootenay River approximately 20 kilometers upstream of its confluence with the Columbia River near the city of Castlegar. The facility was commissioned in 1975 and consists of Kootenay Canal, which diverts water from the Kootenay River into a concrete lined forebay, Kootenay Canal Dam and Kootenay Canal Generating Station. Kootenay Canal is classified as a Key facility for asset management purposes and Kootenay Canal Dam is classified as a Very High consequence dam per the BC Dam Safety Regulation.

BC Hydro has made effective progress restoring the health of several components of this generating facility over the past 10 years through investments totaling over $40 million. Investments in the facility equipment have included upgrades to the intake gantry crane and replacement of the station service transformer. Dam Safety investments have included the installation of a membrane liner within the forebay to seal off leakage through joints between the concrete slabs. The most significant remaining issues and risks associated with the Kootenay Canal facility include:

- Generating Equipment:
  - Poor condition of all four generators and one governor that could impact the reliability of the generating equipment and result in loss of generation;
  - Failed coatings on the penstocks and intake operating gates that will lead to corrosion and metal loss and reduce the life of the penstocks and the gates;
  - Deficiencies in the existing fire protection system that have increased the risk of system failure due to accelerated corrosion and potential rupture of the piping;
- Dam Safety:
  - Failing and leaking joints between the canal's concrete slabs—upstream of the remediated forebay—that could eventually allow seepage to undermine the slabs. This risk is currently managed by regular visual inspections of the canal's concrete liner and embankments and by measurements of seepage through collection weirs.

Summarize Solution:

The Kootenay Canal Facility Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed) considering factors such as condition, rate of deterioration, the operating environment and criticality.

In the short term, investments to address the risks associated with the protection and control equipment as well as the powerhouse crane will be undertaken. In the medium to long term, investments are proposed to address risks with anticipated degradation of major generating equipment, auxiliary equipment and water passage infrastructure.

Short-Term:

- Generating Equipment:
  - Unit 1 to 4 protection upgrade;
  - Powerhouse crane upgrade; and
  - Unit 1 to 4 controls modernization.

Medium-Term:

- Generating Equipment:
  - Unit 1 to 4 generator refurbishment;
  - Fire detection and alarm system replacement;
  - Unit 1 to 4 penstocks recoat;
  - Unit 1 to 4 intake operating gate refurbishment.
  - AC station service upgrade; and
  - Unit 1 to 4 cooling water piping replacement.

- Dam Safety:
    - Canal concrete liner slab joints upgrade;

Long-Term:

- Generating Equipment:
    - Unit 1 to 4 turbine overhaul;
    - Unit 1 to 2 transformer replacement; and
    - Fire protection piping replacement.

Name of Capital Strategy, Plan or Study:
Ladore Facility Asset Plan

Summarize Issue:

The two unit, 47 MW Ladore facility is located on Vancouver Island and was commissioned in 1958. It was built as part of the Campbell River development and forms part of the Campbell River system with the Strathcona facility and John Hart facility located upstream and downstream, respectively. The facility consists of the Lower Campbell Lake Reservoir, the Ladore Dam, the Loveland Bay Saddle Dam, the Big Slide and McIvor Bay Natural Barriers and the Ladore Generating Station. The facility is classified as a Strategic facility for asset management purposes and the dams are classified per the BC Dam Safety Regulation as follows:

- Ladore Dam - Extreme consequence;
- Loveland Bay Saddle Dam - Significant consequence; and
- Big Slide Saddle Dam - Significant consequence.

In 2009 BC Hydro initiated the top-down Campbell River Systems Engineering Assessment and investigated the full range of options for the development of the river system in order to identify how investment should be prioritized to deliver safe and sustainable long-term management of the river system assets.

In recent years, a number of capital investments totaling $25 million have been made at the Ladore facility. Recent investments have included the replacement of the intake gates, upgrade of the oil containment and replacement of the powerhouse and tailrace cranes.

The most significant remaining issues and risks at the Ladore facility include:

- Generating Equipment:
  - The protection and controls equipment is over 55-years old, with deteriorated electro-mechanical relays with no failure detection system which pose a risk of misoperation leading to increased equipment damage and extended outage;
  - Poor condition of the Unit 1 and Unit 2 generators, turbines and transformers increases the reliability risks of both generating units and could result in an extended forced outage; and
  - The degraded condition of the mechanical auxiliary equipment which increases the potential for forced outages of the main generating equipment.
- Dam Safety:
  - Inadequate seismic withstand of the spillway gates and hoist structures which, following a major earthquake expected to occur, on average, once every 1200 years, could result in a loss of control of the reservoir; and
  - Deficiencies in the operational reliability of the spillway gates that could result in their failure to open as needed in a flood event.

Summarize Solution:

The Ladore Facility Asset Plan presents a unit-by-unit redevelopment strategy to address the identified risks and overall condition of the facility while considering factors such as condition, rate of deterioration, the operating environment, and criticality.

In the short term, activities to address the risks with the spillway gates, protection and control systems and the condition of Unit 1 will be started to mitigate reliability and power supply risks. In the medium to longer term, redevelopment of Unit 2 is expected to be started in order to mitigate reliability and power supply risks associated with Unit 2.

Short-Term:

- Generating Equipment:
  - Address protection and control issues; and
  - Unit 1 redevelopment.

- Dam Safety:
  - Seismic and reliability upgrades of Ladore Dam spillway gate systems.

Medium-Term:

- Generating Equipment:
  - Unit 2 redevelopment; and
  - Mechanical auxiliary equipment upgrades.

Name of Capital Strategy, Plan or Study:
Coquitlam-Buntzen Facility Asset Plan

Summarize Issue:

The single unit, 60 MW Lake Buntzen facility is located in Metro Vancouver and was commissioned in 1951. It is part of the Coquitlam-Buntzen system, which consists of Coquitlam Reservoir and Dam, Coquitlam diversion tunnel, Buntzen Lake Reservoir and Dam, and Lake Buntzen 1 and 2 Generating Stations. Lake Buntzen is classified as a Strategic facility for asset management purposes. Coquitlam Dam is an Extreme consequence dam and Lake Buntzen Dam is a Significant consequence dam per the BC Dam Safety Regulation.

The original Lake Buntzen 1 Generating Station first went into service in 1903. In 1951 the original generating units were replaced with a single 60 MW unit that continues to operate today. The three unit Lake Buntzen 2 Generating Station was built in 1913, and permanently ceased operation 2013. The original Coquitlam Dam, constructed in 1905, was replaced by a second dam in 1914. This second dam was found to be severely deficient under earthquake loading, and a new embankment dam was constructed on the downstream toe of the second dam in 2008. The second dam remains in place, but is not relied upon to retain the reservoir.

BC Hydro improved the health of the Coquitlam-Buntzen system through a number of investments in recent years totaling over $90 million. Investments in generating equipment have included a turbine upgrade. Dam Safety investments have included the construction of a new Coquitlam Dam, upgrades to the Coquitlam Dam low level outlet gates, and an upgrade to the Lake Buntzen spillway.

The most significant remaining issues and risks associated with the Coquitlam-Buntzen system include:

- Generating Equipment:
  - Poor condition of the Coquitlam tunnel gates, a failure of which would result in the loss of control of the transfer of water from Coquitlam Reservoir to Buntzen Lake Reservoir;
  - Poor condition of the Lake Buntzen 1 powerhouse crane, which decreases crane reliability and increases worker safety risks;
  - Failed interior and exterior coatings on the Lake Buntzen 1 penstock which will lead to corrosion and metal loss of the underlying material, thereby reducing the life of the penstock. A finite window of opportunity exists to re-coat the asset before a much more extensive refurbishment or replacement is required; and
  - Poor condition of the Lake Buntzen 1 generator, which elevates the reliability risks associated with the single generating unit and increasing the likelihood that the facility may experience an extended forced outage.
- Dam Safety:
  - Potential failure of the Coquitlam tunnel's inlet and outlet portals during an earthquake expected to occur, on average, once every 100 to 200 years;
  - Potential failure of the Coquitlam Low Level Outlet structure in an earthquake expected to occur, on average, once every 3,500 to 5,000 years; and
  - Insufficient capacity of the Lake Buntzen 1 spillway that increases the risk of overtopping Buntzen Dam and flooding Lake Buntzen 1 Generating Station, a risk that BC Hydro is currently accepting but managing through increased surveillance when reservoir elevations are high.

Summarize Solution:

The Coquitlam-Buntzen Facility Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed), considering factors such as asset condition, rate of deterioration, the operating environment, and criticality.

In the short term, the focus will be on risks associated with the ability to transfer water between Coquitlam Reservoir and Lake Buntzen Reservoir, as well as reliability of the Lake Buntzen 1 penstock and generating unit. In the medium to longer term, investments will continue to address the risks associated with the penstock as well as addressing the seismic withstand capability of the Coquitlam tunnel inlet portal and the flood discharge capability of Lake Buntzen 1 generating station.

Short-Term:

- Generating Equipment
  - Lake Buntzen 1 Powerhouse Crane Upgrade;
  - Coquitlam Tunnel Gates Refurbishment;
  - Lake Buntzen 1 Exterior Penstock Recoat; and
  - Lake Buntzen 1 Generator Replacement.

Medium- and Long-Term:

- Generating Equipment
  - Lake Buntzen 1 Interior Penstock Recoat;
  - Coquitlam Tunnel Inlet Portal Seismic Upgrade; and
  - Lake Buntzen 1 Flood Discharge Capability Improvement.

The risks associated with the low seismic withstand of the Coquitlam Tunnel outlet portal, and the Coquitlam Dam Low Level Outlet structure are monitored and will be retained as the consequences are expected to be low.

Name of Capital Strategy, Plan or Study: **Mica Facility Asset Plan**
Summarize Issue: The six unit, 2780 MW Mica facility is located on the Columbia River north of the town of Revelstoke. It was constructed under the terms of the Columbia River Treaty. The dam was completed in 1973, two generating units were installed and commissioned in 1976, two more in 1977 and the final two in 2015. The facility includes Kinbasket Lake Reservoir, Mica Dam and Mica Generating Station. Mica is classified as a Key facility for asset management purposes and Mica Dam is classified as an Extreme consequence dam per the BC Dam Safety Regulation. Approximately $700 million has been invested at Mica over the past ten years, $600 million of which was to upgrade the gas insulated switchgear system and commission the fifth and sixth generating units. Investments in the generating equipment have also included a Unit 1 transformer replacement and battery and charger replacement. Dam Safety investments within this period have generally been limited to instrumentation improvements. The most significant remaining issues and risks associated with the Mica facility include: • Generating Equipment; - Poor condition of the original unit transformers, line reactors and Unit 1 and 2 turbines increases the reliability risk and may result in forced outages; - Obsolescence of the original Unit 1 to 4 circuit breakers, exciter controls and governor controls increases the reliability risk and may lead to forced outages; - Deterioration of the water passage protective coatings will lead to corrosion and metal loss of the underlying material thereby reducing the life of the penstock; - Poor condition of the powerhouse cranes and limited capacity of the crane rails may impact the ability to lift loads associated with unit refurbishment work; - Poor condition of the Heating, Ventilation and Air Conditioning (**HVAC**) systems increases the safety risk in the underground powerhouse as these systems are relied upon to move air through the facility in emergency situations; and - Poor condition of the Unit 1 and 2 cooling water piping increases the risk of piping failure resulting in damage to the facility or equipment. • Dam Safety: - Inadequate seismic withstand of the flood discharge systems (spillway and outlet works) which, following a major earthquake expected to occur, on average, once every 2000 to 3000 years, could result in a loss of control of the reservoir; - Deficiencies in the operational reliability of the spillway gates that could result in their failure to open as needed in a flood event, for which the risk is currently managed by regular testing and maintenance of the existing systems; and - Potential failure of the nearby Dutchman's Ridge and Little Chief Slide into Kinbasket Reservoir under unusual loads (e.g., earthquake or extreme precipitation), which could lead to overtopping of the dam. This risk is managed through a sustained program of slope surveillance and monitoring.
Summarize Solution: With the recent construction of Units 5 and 6, Mica is continuing a period of planned refurbishment of the original four units that were installed and commissioned in the 1970s. The Facility Asset Plan proposes a component by component replacement strategy to sustain operation at the Mica Facility by mitigating the risk of failure of individual assets on an as needed basis (e.g., condition, rate of deterioration, operating environment, and criticality). Investments in the short-term will focus on the highest priority safety and reliability risks in the powerhouse that can be mitigated without an extended outage and on addressing high consequence risks associated with current spillway and outlet works deficiencies. Work in the medium to long-term will be undertaken with continued focus on equipment that is in poor

condition but requires longer duration outages, as well as works to maintain or improve the stability of Dutchman's Ridge and Little Chief Slide.

Short-Term:

- Generating Equipment:
  - Powerhouse cranes and crane rails upgrade (planned In-service Date fiscal 2020);
  - Unit 1 to 4 unit transformer replacements;
  - Unit 1 to 4 exciter controls, governor controls and unit protection replacement;
  - HVAC system upgrades; and
  - 600 V switchgear and essential electrical bus upgrades.
- Dam Safety
  - Flood discharge facilities seismic and reliability upgrades.

Medium-Term:

- Generating Equipment
  - Unit 1 and 2 turbine overhauls;
  - Unit 1-4 circuit breaker and iso-phase bus replacement;
  - 500 kV line reactor replacement;
  - Unit 1 and 2 cooling water piping; and
  - Water passage coatings restoration.
- Dam Safety
  - Little Chief slope inclinometer installation.

Long-Term:

- Generating Equipment
  - Unit 3 and 4 turbine overhauls; and
  - Unit 3 and 4 cooling water replacement.
- Dam Safety
  - Dutchman's Ridge and Little Chief Slide: slope stability improvements or measures to mitigate impacts of failure.

Name of Capital Strategy, Plan or Study:
Mica Townsite Facility Asset Plan

Summarize Issue:

The Mica facility is in a remote location, approximately 130 km north of the town of Revelstoke. The Mica Townsite, owned by BC Hydro, consists of a number of permanent buildings for staff accommodation and recreation. The buildings were originally built in the 1960s, and house approximately 50 staff who maintain and operate the plant on an on-going basis.

Additionally, in 2011, a temporary construction camp was built at the townsite to accommodate up to 400 temporary additional staff working on large capital projects at the Mica facility. The construction camp was scheduled to be removed in 2015 after the completion of the installation of Units 5 and 6 at Mica. However, with the timing of current and planned capital projects at Mica, there is a need to modify and extend the life of the camp to accommodate project related staff over the next 10 to 15 years.

BC Hydro has preserved the townsite infrastructure over the past 10 years through investments totaling roughly $3 million. These investments included refurbishing several of the highest risk building roofs and an upgrade of the fire protection system in one of the buildings.

The most significant remaining issues and risks associated with the Mica townsite include:

- Temporary nature of the existing construction camp is insufficient to meet requirements for the next 15 to 20 years;
- Deficiencies in the roofs of many of the key buildings increase the safety risk posed by snow loads as well as the comfort of occupants due to water ingress;
- Deterioration of items such as windows, flooring and furnishings in the permanent accommodations used to house plant operations staff increases the risk of negative impacts to the well-being of the workers and increases the risk of employee turnover; and
- Deficiencies in the Townsite sanitary sewage system increase the risk of system failure which may have environmental, safety and financial risks.

Summarize Solution:

The Mica Townsite is in a period of planned refurbishment to maintain the infrastructure for both permanent staff supporting operations and maintenance and project related staff supporting the delivery of capital projects.

The proposed strategy for Mica Townsite is to convert portions of the temporary accommodations into permanent facilities, expand the kitchen and dining areas, and address the deteriorating condition of the permanent structures and infrastructure, to ensure continued availability and reliability of the Townsite.

Short-Term:

- Permanent accommodation capacity augmentation through conversion of temporary facilities essential for planned capital projects (planned In-service Date fiscal 2020);
- Building roof refurbishments to address the most significant roof issues;
- Staff accommodations refurbishment; and
- Townsite sanitary sewage system refurbishment.

Name of Capital Strategy, Plan or Study:
Peace Canyon Facility Asset Plan

Summarize Issue:

The four-unit, 700 MW Peace Canyon facility is located 6 km upstream of Hudson's Hope and 23 km downstream of the G.M. Shrum Generating Station on the Peace River. It was placed into service in 1980 and is comprised of the Dinosaur Lake Reservoir, the Peace Canyon Dam, and the Peace Canyon Generating Station. Peace Canyon is classified as a Key generating facility for asset management purposes and Peace Canyon Dam is classified as an Extreme consequence dam per the BC Dam Safety Regulation.

BC Hydro has actively maintained the health of this important generating facility over the past 10 years though a number of investments totaling over $100 million. Investments in the generating equipment include replacement of the generator stators and turbine overhauls.

The most significant remaining issues and risks associated with the Peace Canyon facility include:

- Generating Equipment:
  - Failed exterior coatings of the penstock and scroll case which will lead to corrosion and metal loss of the underlying material, thereby reducing the life of the penstock. A finite window of opportunity exists to re-coat the asset before a much more extensive refurbishment or replacement would be required;
  - Increased risk of water leakages from poor condition of the high and low pressure piping systems that may cause damage to critical and sensitive equipment; and
  - Poor condition of Unit 1 to 4 Exciters.
- Dam Safety:
  - Deficiencies in the operational reliability of the spillway gates that could result in their failure to open as needed in a flood event, the risk of which is currently managed by regular gate testing and maintenance as required;
  - Continuing erosion of rock at the rim of the plunge pool downstream of the spillway structure that could eventually progress upstream to the toe of the spillway and threaten that structure's stability, currently managed by the performance of underwater inspections following spills;
  - Potential failure of the dam in a major earthquake expected to occur, on average, once every 2,500 years; and
  - Diminishing efficiency of the dam's foundation drainage systems that could eventually result in insufficient stability of the dam structure, which is currently managed by continuous monitoring of uplift pressures and drain cleaning as required.

Summarize Solution:

The Peace Canyon Facility Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. Capital upgrade projects are carefully planned in coordination with G.M. Shrum as operations at G.M. Shrum can be restricted when Peace Canyon units are out of service. In the short-term, projects are staged to prioritize reliability investments in key generating equipment. In the medium to long term, projects are staged to restore water passage coatings, improve the reliability of the flood discharge system and improve the seismic withstand of the Peace Canyon Dam.

Short-Term:

- Generating Equipment:
  - Unit 1 to 4 Exciter Replacement; and
  - High and Low Pressure Piping Replacement.
- Dam Safety:
  - Re-drilling of the dam's foundation drains.

Medium-Term:

- Generating Equipment:
  - External Penstock Recoating.
- Dam Safety:
  - Spillway gates control upgrade;
  - Peace Canyon Dam seismic upgrade; and
  - Dam foundation drain rehabilitation.

Long-Term:

- Dam Safety:
  - Spillway gates electrical and mechanical upgrades.

The risk that the spillway plunge pool may continue to erode during major spill events is currently being managed by monitoring the progression of the eroded area. Capital investment is not planned at this time; however, future work may be required to ensure that the spillway structure does not become undermined.

Name of Capital Strategy, Plan or Study:
Generation Asset Management Strategy - Penstock Recoating

Summarize Issue:

There are 67 penstocks supplying 79 units at BC Hydro's hydroelectric generating stations. Penstocks are high-value assets that convey water to a generating unit's turbine. Generally, the exterior and interior surfaces of the steel penstocks are coated to protect the underlying material from abrasion, corrosion, and ultimately material loss and a reduction in structural strength.

Over time, the coatings wear, degrade and fail, leading to corrosion of the underlying penstock material. Recoating of the penstock ensures that its life can be preserved, however, if the window of opportunity to recoat the penstock is missed, the underlying material will continue to corrode over time, and eventually, the penstock can no longer be used to safely convey water to the generating facility.

If the corrosion is too severe, it may not be possible to re-coat the penstock, resulting in a number of issues and risks:

- Financial - A much more expensive penstock replacement and significantly longer generating unit outage would be required;
- Reliability - the asset can no longer safely convey water to the turbine forcing the generator to be taken out of service; and
- Safety and Environmental –severe corrosion and metal loss can result in sudden and large uncontrolled releases of water. BC Hydro mitigates this risk by monitoring the condition of its penstocks over time and would pro-actively remove an asset from service if degradation became too severe.

Currently, approximately 13 penstocks are between 50 and 60 years old, and 23 are more than 60-years old (of which three are no longer in service). Age is one factor but operating environment and water pressure, the quality of the coating and design factors have a larger effect on the asset health. Approximately 32 (48 per cent) of the penstocks have been assessed as Poor or Unsatisfactory, primarily due to issues with the coatings, indicating there is an increased likelihood of loss of structural strength if not addressed in a timely manner.

Summarize Solution:

BC Hydro has undertaken a number of activities to better understand the condition of the penstocks and coatings. Work was undertaken to assess the health of all of its penstocks to establish a baseline of condition and risks. An enhanced penstock asset health methodology was developed to assess both the condition of the penstocks and its coatings. The information has been used to identify the poorest condition penstock coatings and to estimate the window of time remaining to re-coat the penstock before a replacement of the asset would be required.

As a result of this work, a number of capital projects have been identified to remediate the risks associated with the higher risk penstocks with a focus on penstock coatings. The planned scope and timing of these investments has considered factors such as:

- The need to re-coat both the exterior and exterior, or whether one surface is a higher priority;
- The need to recoat an entire penstock or whether only localized coating refurbishment would be sufficient;
- The opportunity to co-ordinate the investment with similar duration unit outages; and
- The operating pressure of the penstock with higher pressure penstocks generally given higher priority for re-coating.

Given the coating condition of a large number of penstocks, consideration was given to a project delivery strategy that minimizes costs, reduces quality risks and more efficiently delivers the recoating projects.

Short-Term:

The condition of assets is reviewed on a regular basis considering such factors as recurring test results, visual inspections, and detailed engineering assessments. This information is used to assess the condition of each penstock to help prepare a consolidated list across the fleet to identify the most appropriate time to address the risks while best coordinating other planned generating unit outages. Below is a list of those penstocks with higher priority requiring investment in the short-term:

- Ash River steel penstock (external recoating);
- Bridge River 1 penstocks 1 to 4 (internal recoating;
- Bridge River 2 penstock 2 (internal recoating);
- Cheakamus penstocks 1 and 2 (internal and external recoating);
- Jordan River penstock (external recoating);
- Lake Buntzen 1 penstock (external recoating);
- Puntledge steel penstock (internal and external recoating); and
- Wahleach penstock (internal and external recoating).

Medium-Term:

There are a number of penstock coating refurbishment projects that will need to be initiated in the medium term. The strategy and prioritization will be adjusted over time to respond to new information becoming available from penstock condition assessments. Currently, the following locations have been identified as higher risk:

- Bridge River 1 penstocks 1 to 4 (external recoating);
- Kootenay Canal penstocks 1 to 4 (internal recoating);
- Lake Buntzen 1 penstock (internal recoating);
- Peace Canyon penstocks 1 to 4 (external recoating);
- Walter Hardman penstock (exterior recoating);
- Mica Creek penstocks 1 to 6 (targeted recoating);
- La Joie south penstock (interior recoating);
- Seton penstock (interior recoating); and
- GM Shrum penstocks 1 to 10 (interior recoating).

Long-Term:

Over the next 10 years, a number of penstock coatings will continue to degrade. Remediation of the risks associated with these assets will be required in the long-term, applying similar assessment and prioritization techniques to those outlined above.

Name of Capital Strategy, Plan or Study:
Puntledge Facility Asset Plan

Summarize Issue:

The single unit, 24 MW Puntledge facility is located near the City of Courtenay on Vancouver Island. The facility is comprised of the Comox Lake Reservoir, Comox Dam, Puntledge Diversion Dam and the Puntledge Generating Station. Both dams were constructed in 1912 and the generating station was constructed in 1955. Puntledge is classified as a Strategic generating facility for asset management purposes. The Dams are classified as follows per BC Dam Safety Regulation:

- Comox Dam - Extreme consequence; and
- Puntledge Diversion Dam - Very High consequence

Over the past 10 years, a small number of capital investments totaling over $5 million have been undertaken at Puntledge in order to mitigate known public safety risks associated with the water level gauges, public warning system, and flow control system and to address penstock reliability issues.

The most significant remaining issues and risks associated with the Puntledge facility include:

- Generating Equipment:
  - The intake operating gates and pressure release valves are subject to a number of issues which can impact their reliable operation resulting in an elevated public safety risk due to unexpected changes in downstream water releases;
  - Poor condition of the generator which increases the reliability risk and increases the likelihood that the facility may experience an extended forced outage;
  - The ongoing deterioration and accelerated decay of the woodstave penstock increases the risk that the asset will no longer be able to safely convey water; and
  - The coating of the steel penstock has failed along the majority of its length leading to corrosion and metal loss of the underlying material thereby reducing the life of the penstock. A finite window of opportunity exists to re-coat the asset before a much more extensive rehabilitation or replacement is required.
- Dam Safety:
  - The spillway operating gates at Comox Dam have deficiencies in reliability that could render them inoperative when needed during high inflows and could lead to overtopping of the dam and abutments, the risk of which is being managed by frequent repairs to deteriorating components;
  - The Comox and Puntledge Diversion Dams have seismic deficiencies that, in the event of an earthquake expected to occur, on average, once every 1000 years, could lead to their failure and consequent downstream impacts;
  - The right abutment of Comox Dam is susceptible to erosion during low probability flood conditions which could result in a breach and uncontrolled release of Comox Lake Reservoir; and
  - Potential overtopping of Comox Dam in the event of the extreme design flood expected to occur, on average, once every 1000 years.

Summarize Solution:

The Puntledge Facility Asset Plan proposes a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed) considering factors such as condition, rate of deterioration, the operating environment and criticality.

In the short term, activities to address the issues with the steel penstock and flow control and water level monitoring systems will be undertaken as these have been identified as being higher priority public safety risks. In the medium-term, activities will be started to address the condition of the generating unit and the seismic withstand of the Puntledge Diversion Dam in order to mitigate reliability and dam safety risks respectively. In the longer-term, seismic withstand of the Comox Dam will be addressed along with the condition of the wood stave penstock.

Short-Term:

- Generating Equipment:
  - Steel penstock recoating.
- Dam Safety:
  - Flow control improvements; and
  - Upgrades to the water level monitoring and public safety warning systems.

Medium-Term:

- Generating Equipment:
  - Generator refurbishment; and
  - Turbine refurbishment.
- Dam Safety:
  - Puntledge Diversion Dam structure seismic upgrade.

Long-Term:

- Dam Safety:
  - Wood stave penstock replacement; and
  - Comox Dam seismic upgrades.

At this time, no investment is proposed to address the overtopping risk of Comox Dam structure due to measures within ongoing and planned projects to mitigate the downstream safety risk.

Name of Capital Strategy, Plan or Study:
Revelstoke Facility Asset Plan

Summarize Issue:

The five-unit, 2391 MW Revelstoke facility was built in 1984 and is located on the main stem of the Columbia River near the town of Revelstoke. The facility includes the Revelstoke Reservoir, the Revelstoke Dam and the Revelstoke Generating Station. The first four generating units went into service in 1984, the fifth unit went into service in 2011, and there is space for a sixth unit. Revelstoke is classified as a Key facility for asset management purposes and Revelstoke Dam is classified as an Extreme consequence dam per the BC Dam Safety Regulation.

BC Hydro has made substantial progress in maintaining the health and increasing the capacity of this generating facility over the past 10 years through a number of investments totaling over $230 million. Investments in the generating equipment have included the installation of generating Unit 5, upgrades to the powerhouse crane and facility security upgrades.

The most significant remaining issues and risks associated with the Revelstoke facility include:

- Generating Equipment;
  - Poor condition of the Unit 2 to 4 generators increases the reliability risk and may result in long unit outages;
  - Configuration and expected deterioration of the iso-phase bus increases the reliability risk associated with unit outages;
  - Obsolescence of the Unit 1 to 4 exciter and governor controls increases the reliability risk and may result in unit outages; and
  - Poor condition of six of the twelve Unit 1 to 4 transformers increases the reliability risk and may result in long unit outages.
- Dam Safety:
  - The potential for Downie Slide, a slow-moving land mass on the Revelstoke Reservoir, to slide into and block the Columbia River, which is managed under the terms of the water license by maintaining an extensive network of drainage throughout the extent of the slide and by continuously monitoring the slide's movements and pore water pressures;
  - Potential failure of portions of the rock slope at the dam's left abutment that could impact the penstocks and powerhouse or damage the rock anchors that stabilize larger masses of rock on the slope, which is currently managed by monitoring and surveillance;
  - High hydraulic gradients around the earthfill dam's vertical movement gauge casings could drive water flows around these casings and lead to internal erosion of the earthfill materials, the risk of which is currently managed by continuous monitoring of water pressures in the dam core and water levels in the casings; and
  - Inadequate reliability and seismic withstand of the flood discharge (spillway) system that may impact our ability to manage water in a controlled manner during high inflow events or in the aftermath of an earthquake, for which the risk is currently managed by regular gate testing and maintenance.

Summarize Solution:

The Revelstoke Facility Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. Implementing the investment strategy at Revelstoke facility is at the early stages which include refurbishing the original equipment and infrastructure. Adding the sixth generating unit is also planned in order to meet the long-term system capacity requirements.

In the short-term, projects are staged to prioritize investments required for safe and reliable generation and also to leverage facility growth potential to support meeting system capacity needs. Timing of the addition of the sixth unit and coordination with other Revelstoke projects creates risk due to limited physical space in the powerhouse constraining the ability to carry out several major projects at once.

Investments to monitor and manage risks related to landslides are ongoing and proposed to continue through the medium-term.

Short-Term:

- Generating Equipment:
  - Unit 1 to 4 generator stator replacements;
  - 600 V switchgear replacement; and
  - Addition of the sixth generating unit.
- Dam Safety:
  - Left Bank slope stability improvements to reduce the risk of rockfall and protect the rock anchors in the slope from damage;
  - Downie Slide instrumentation replacements to ensure continued monitoring of water pressures and deformations in the slope in accordance with the dam's water license; and
  - Rehabilitation or decommissioning of the earthfill dam's vertical movement gauges.

Medium-Term:

- Generating Equipment:
  - Addition of the third section of gas insulated switchgear bus;
  - Unit 1 to 4 transformer replacements;
  - Unit 1 to 4 exciter and governor controls replacement; and
  - Databus system replacement.
- Dam Safety:
  - Flood discharge (spillway) system reliability improvements; and
  - Remediation of the slope drainage system at Downie Slide in the timeframe when it's effectiveness is expected to diminish, in accordance with the dam's water license.

Long-Term:

- Generating Equipment:
  - Unit 1 to 4 water passage coating restoration; and
  - Unit 1 to 4 turbine overhauls.

Name of Capital Strategy, Plan or Study:
Seton Facility Asset Plan

Summarize Issue:

The single unit, 44 MW Seton facility is located near Lillooet and was commissioned in 1956. It consists of:

- Seton Lake;
- Seton Dam;
- Left Bank Dyke;
- Cayoosh Diversion Tunnel;
- Seton Canal; and
- Seton Generating Station.

Seton is classified as a Strategic facility for asset management purposes and Seton Dam is classified as a High consequence dam per the BC Dam Safety Regulation.

BC Hydro has made a number of investments over the past 10 years totaling more than $35 million. The most significant investments have included the refurbishment of the power canal lining and upgrades to the spillway gates.

The most significant remaining issue and risks associate with Seton facility include:

- Generating Equipment:
  - Poor condition of the generator with increasing risk of a failure that would result in a loss of generation and high flows in the Seton River;
  - Governor reliability concerns. The original governor is no longer supported by Original Equipment Manufacturers and due to wear is more difficult to maintain and calibrate. Failure to control the unit could lead to outages or in worst case a cause an over speed situation resulting in significant damage to the unit;
  - Unit Protection concerns. The original electro-mechanical protection and control systems are no longer supported. Unreliable protection could lead to extended outages if it fails to operate;
  - Poor condition of the turbine with wear, cracking and excessive leakage through the wicket gates increase reliability risk and may result in a forced outage; and
  - Penstock coating failure. A finite window of opportunity exists to re-coat the asset before a much more extensive rehabilitation or replacement is required.
- Dam Safety:
  - Cracks and leaks in the concrete lined canal could lead to a failure of the lining and breach of the canal, the risk of which is being managed by regular inspections and repairs to slow deterioration of the canal lining's overall condition;
  - Inability to close the headworks gates and shut off flow in the event of a canal failure, with current risk management as per the preceding item; and
  - Uncertainty and expected deficiency of the seismic resistance of various civil assets (headworks operating gates, forebay, dam, left dyke, aqueduct, canal). These structures are estimated to be capable of withstanding an earthquake expected to occur once every 1500 to 5000 years, depending on the asset.

Summarize Solution:

The Seton Facility Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. The ability to take outages at the facility can be limited, in light of the important role that the unit plays with respect to water conveyance. The timing of investments that require unit outages have been coordinated, to minimize the impact on water management.

In the short-term, the focus will be on higher priority investments that are required for water management as well as safe and reliable generation. Investments are sequenced to minimize the number and duration of outages required. The medium to longer-term activities will focus on the canal and headworks gates and seismic issues.

Short-Term:

- Generating Equipment:
    - Governor system replacement;
    - Unit protection upgrade;
    - Turbine overhaul;
    - Penstock recoating; and
    - Generator replacement.

Medium-Term:

- Dam Safety:
    - Upgrade headworks gates;
    - Canal refurbishment; and
    - Left Bank Dyke seismic upgrades.

Long-Term:

- Dam Safety:
    - Dam seismic upgrades; and
    - Canal and aqueduct seismic upgrades.

A Dam Safety Investigation is planned to assess and obtain a better understanding of the seismic performance of various civil assets at the facility relative to the criteria for a High consequence dam.

Name of Capital Strategy, Plan or Study:
Seven Mile Facility Asset Plan

Summarize Issue:

The four-unit, 814 MW Seven Mile facility is located on the Pend d'Oreille River in southern British Columbia, upstream of Waneta Dam and downstream of Boundary Dam which is owned by Seattle City Light. The facility includes the Seven Mile Reservoir, the Seven Mile Dam, and the Seven Mile Generating Station. The first unit at Seven Mile Generating Station went into service in 1979, with two additional units installed in 1980 and the fourth unit installed in 2003. Seven Mile is classified as a Key facility for asset management purposes and Seven Mile Dam is classified as an Extreme consequence dam per the BC Dam Safety Regulation.

BC Hydro has invested over $20 million in this facility over the past ten years. Investments in the generating equipment have included the excitation system replacement, Units 1 to 3 stator re-wedging, Units 1 to 4 partial discharge monitoring and Units 1 to 3 protection upgrades. Dam Safety investments have included reservoir slopes instrumentation upgrades and general dam safety improvements.

The most significant remaining issues and risks associated with the Seven Mile facility include:

- Generating Equipment:
  - Poor condition of some of the generating equipment including unit controls, exciter transformers and unit transformers could impact the reliability of the generating equipment and result in loss of generation;
  - Unit 1 to 3 turbines are 37 to 38 years old and have never undergone a major intervention. The latest engineering inspection identified excessive band seal erosion and runner cavitation on these units. Furthermore, due to lack of wicket gate friction devices on these turbines, there is a risk of an undetected shear pin failure event which would result in damage to the wicket gates and unit outages;
  - Failed coatings on the Intake Operating Gates, Intake Maintenance and Draft Tube Maintenance Gates that will lead to corrosion and metal loss and reduce the life of the gates;
  - Poor condition of the powerhouse, tailrace gantry and intake gantry cranes that could impact the reliability of the cranes and their lifting capabilities;
  - Poor condition of the cooling water piping that has increased the risk of piping failure; and
  - Deficiencies in the existing fire alarm and fire protection systems that have increased the risk of system failure due to accelerated corrosion and potential rupture of the piping.
- Dam safety:
  - Deficiencies in the reliability of the flood discharge (spillway) facilities that could lead to a failure of the system to operate on demand during high inflows (a flood or spurious release from Boundary Dam upstream) and result in significant damages to the dam and powerhouse, the risk for which is currently managed through regular gate testing and maintenance; and
  - Deteriorating performance of the dam's drainage system that is continually monitored but, if not remediated, would eventually compromise the dam's stability.

Summarize Solution:

The Seven Mile Facility Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed) considering factors such as condition, rate of deterioration, the operating environment and criticality.

In the short term, the focus will be on higher priority investments required for safe and reliable generation that are sequenced to minimize outages. Medium term activities include those related to maintaining reliable operation of the flood discharge systems. In the long term, activities will continue to focus on investments required to address safety risks and reliability risks for equipment in poor condition.

Short-Term:

- Generating Equipment:
  - Unit 1 to 4 exciter transformer replacement;
  - Powerhouse crane upgrade;
  - Unit 1 to 3 turbine replacement;
  - Fire alarm system replacement;
  - Unit 1 to 4 controls replacement; and
  - Unit 1 transformer replacement.

Medium-Term:

- Generating Equipment:
  - Unit 1 to 3 cooling water piping replacement.
- Dam Safety:
  - Flood Discharge Systems Reliability Improvements; and
  - Foundation drains replacement.

Long-Term:

- Generating Equipment:
  - Unit 2 to 3 transformers replacement;
  - Fire protection piping replacement;
  - Unit 1 to 3 generators replacement;
  - Intake operating gate refurbishment; and
  - Intake gantry crane upgrade.

Name of Capital Strategy, Plan or Study: **Stave Falls New Facility Asset Plan**
Summarize Issue: The two unit, 90 MW Stave Falls New facility is located in the Lower Mainland and was constructed in 1999. It forms part of the Stave River system, with the Alouette facility and Ruskin facility located upstream and downstream, respectively. It consists of the Stave Lake Reservoir, Stave Falls Dam, Blind Slough Dam, and Stave Falls New Generating Station. Stave Falls New is classified as a Strategic facility for asset management purposes. Stave Falls Dam and Blind Slough Dam are rated as Extreme consequence dams per the BC Dam Safety Regulation. The original Stave Falls Generating Station was developed in 1911, and permanently ceased operation when Stave Falls New Generating Station was placed into service. BC Hydro has made a number of investments over the past 10 years totaling over $50 million. Investments in the generating equipment have included site grounding upgrade and a tailrace gantry crane upgrade. Dam Safety investments have included upgrades to Blind Slough Dam's spillway gates and gantry crane. The most significant remaining issues and risks associated with the Stave Falls New facility include: • Generating Equipment: - A design deficiency with the Unit 1 and Unit 2 turbines that could impact the reliability of the generating units and result in loss of generation; and - Potential equipment reliability risks due to expected obsolescence with the unique digital controls systems that could result in loss of generation due to limited spare parts and manufacturer support.
Summarize Solution: The Stave Falls New Facility Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. In the short-term, the focus will be addressing risks associated with the generating units. The medium to longer-term activities will focus on risks associated with the generating unit control systems. **Short-Term:** • Generating Equipment: - Units 1 and 2 Turbine Pitch Assemblies Improvement. **Medium- and Long-Term:** • Generating Equipment: - Unit 1 Controls Upgrade; and - Unit 2 Controls Upgrade.

Name of Capital Strategy, Plan or Study:
Strathcona Facility Asset Plan

Summarize Issue:

The two unit 64 MW Strathcona facility is located on Vancouver Island and was constructed in 1958 (Unit 1) and 1968 (Unit 2). Strathcona forms part of the Campbell River system, with Ladore and John Hart facilities located downstream. The facility includes the Upper Campbell Reservoir, the Strathcona Dam, Crest Creek Diversion Dike, and the Strathcona Generating Station. Strathcona is classified as a Strategic facility for asset management purposes. Per the BC Dam Safety Regulation:

- Strathcona Dam is rated an Extreme consequence dam; and
- Crest Creek Diversion Dike is rated a Significant consequence dam.

In 2009 BC Hydro initiated the Campbell River Systems Engineering Assessment and investigated the full range of options for the development of the river system in order to identify how investment should be prioritized to deliver safe and sustainable long-term management of the river system assets. Remediation of seismic concerns may mean that the generating facility cannot continue to operate in its current location. This still requires extensive investigation; however, the level of investment in the generating equipment has been limited, while the overall strategy is clarified. Over the past 10 years, $25 million of the total $35 million in investments made at the facility have been to implement seismic upgrades with the remaining investments made on essential activities on generating equipment such as the intake gates, one of the generators, and turbine inlet valves (**TIVs**).

The most significant remaining issues and risks associated with the Strathcona facility include:

- Generating Equipment:
  - Poor condition of the Unit 1 generator increases the reliability risk and could result in an extended forced outage resulting in a loss of generation and inability to maintain necessary water conveyance past the facility.
- Dam Safety:
  - Expectedly poor post-seismic performance of the embankment dam after an earthquake occurring, on average, about once every 500 years;
  - Insufficient seismic withstand of the intake tower and the water conduit and penstock that pass under the dam to the powerhouse, raising concerns for their failure in an earthquake occurring, on average, about once every 500 to 1,000 years, resulting in seepage through the dam fills and potential dam failure;
  - Deficiencies in the operational reliability of the spillway gates that could result in their failure to open as needed in a flood event;
  - Insufficient seismic withstand of the spillway gates and hoist structures that, in an earthquake occurring, on average, about once every 1,000 years, could fail and result in a loss of containment and/or control of the reservoir; and
  - Inability to draw down the reservoir to a sufficiently low elevation following a major earthquake, as required by the expectedly poor post-seismic performance of the dam (described above).

Summarize Solution:

The Strathcona Facility Asset Plan presents a strategy that initially focuses on addressing the highest priority water conveyance and dam safety items. The strategy to be taken for upgrades to the dam and ancillary flow control structures is described within the Campbell River Systems Engineering Assessment which is referenced above and has its own summary within Appendix K. Limited investments in the existing generating equipment will be considered on a component by component basis (i.e., undertake discrete investments, as needed), considering factors such as condition, rate of deterioration, the operating environment and criticality.

In the short term, activities will address the identified risks and issues associated with the reservoir discharge capability and generating units, in order to address immediate high priority dam safety and reliability risks, respectively. In the medium term, the focus will remain on water conveyance and addressing the seismic withstand risks associated with the dam. It is possible that the solution required to remediate the seismic issues associated with the dam may result in an inability to continue generation within the existing powerhouse. If this is the case, in the long-term, opportunities to redevelop the generating station will be investigated.

Short-Term:

- Generating Equipment:
    - Generator (G1) refurbishment.
- Dam Safety:
    - Upgrade of the reservoir discharge facilities to provide sufficient operational reliability, required seismic withstand, post-earthquake drawdown capability, and capability to provide compensatory flows in the event of lost or discontinued generation.

Medium-Term:

- Dam Safety:
    - Embankment dam seismic upgrades; and
    - Possible decommissioning of the intake tower, water conduit and penstock under the dam and concomitant decommissioning of the generating station or reducing the Generating Station to a non-operational station.

Long-Term:

- Generating Equipment:
    - Potential redevelopment of the Strathcona generating station.

Name of Capital Strategy, Plan or Study:
Wahleach Facility Asset Plan

Summarize Issue:

The single unit, 61 MW Wahleach facility is located in the Lower Mainland and was commissioned in 1952. It consists of the Jones Lake Reservoir, Wahleach Dam, Boulder Creek Diversion Dyke, Jones Lake Intake structure, and a water conveyance tunnel and penstock leading to the Wahleach Generating Station. Wahleach is classified as a Strategic facility for asset management purposes and Wahleach Dam is classified as a Very High consequence dam per the BC Dam Safety Regulation.

BC Hydro has maintained the health of the Wahleach facility through a number of investments over the past 10 years totaling over $20 million. Investments have been focused on generating equipment, which included penstock inlet valve, governor, exciter, protection and control, transformer, switchgear, and cooling water replacements.

The most significant remaining issues and risks associated with the Wahleach facility include:

- Generating Equipment:
  - Poor condition of the generator, elevating the reliability risks associated with the single unit and increasing the likelihood that the facility may experience an extended forced outage;
  - The coatings on the penstock and tunnel steel liner have failed which will lead to corrosion and metal loss of the underlying material, thereby reducing the life of the penstock. A finite window of opportunity exists to re-coat the assets before a much more extensive refurbishment or replacement is required; and
  - There is an increased risk of failure associated with the fire protection system due to accelerated corrosion which could lead to potential rupture of the piping and flooding of the powerhouse.
- Dam Safety:
  - Potential defects in the seepage control sheet piles at Wahleach Dam that could lead to erosion of dam or foundation materials and risk of dam failure. This risk is being managed by monitoring seepage through instrumentation and weekly inspections, and a response plan is in place in the event that any sign of significant seepage through the dam is observed;
  - Potential failure of the intake gates at Jones Lake during a major earthquake occurring, on average, about once every 4,800 years, which would prevent the closure of the water passage and cessation of flows to what would likely be a damaged generating station and could result in the inundation of adjacent utility and transportation corridors; and
  - Potential slope failure at Four Brothers Mountain that could result in the loss of the Wahleach facility and impact adjacent utility and transportation corridors.

Summarize Solution:

The Wahleach Facility Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. In the short-term, the focus will be on higher-priority investments required for safe and reliable generation that are sequenced to minimize outages. The medium to longer-term activities will focus sustaining safe reservoir containment at Wahleach.

Short-Term:

- Generating Equipment:
  - Generator refurbishment;
  - Penstock and tunnel liner coatings replacement; and
  - Fire protection system upgrade.

Medium- and Long-Term:

- Dam Safety:
    - Intake Tower and Gates seismic upgrade; and
    - Dam foundation seepage control upgrade.

The potential for a slope failure at Four Brothers Mountain is a retained risk, with no practicable means available to reduce or eliminate it. BC Hydro has implemented an ongoing surveillance program to identify changes in the slope's behaviour and to provide warning of impending instability.

Name of Capital Strategy, Plan or Study:
Abbotsford Area Study

Summarize Issue:

The Abbotsford area is supplied by a 230 kV and 60 kV transmission system and the following four substations:

- Mount Lehman has a capacity of 100 MVA, and was built in 2007;
- Gloucester has a capacity of 25 MVA, and was built in 2002;
- Clayburn has a capacity of 180 MVA, and was built in 1984; and
- Sumas Way has a capacity of 55 MVA, and was built in 1977.

The four substations supply the entire load in the study area which extends from about 248 St in Langley to Sumas Prairie east of the City of Abbotsford, and from the Fraser River to the Canada/USA border. The Abbotsford area has approximately 60,000 customers and a peak load of 306 MVA in fiscal 2017. The present area firm capacity is 360 MVA.

The City of Abbotsford, the largest municipality in this area, has a population of over 130,000. It is the largest municipality in the Fraser Valley Regional District and the fifth largest municipality in British Columbia.

A number of investments have been made in this area in the last 20 years totaling over $65 million. The recent investments have included the construction of two substations: Mount Lehman Substation and Gloucester Substation, together with the decommissioning of the old Abbotsford substation.

The most significant issues and risks remaining in the Abbotsford area include:

- Clayburn substation has feeder sections that were designed to be compact in size and now present safety risks for workers due to limited clearance between energized equipment and ground. This risk is currently partially mitigated through physical barriers and warning signs, however, workers are unable to safely and efficiently work on the equipment without taking extended customer outages. As a result, some maintenance work at the substation cannot be completed;
- At the Sumas Way substation, all of the equipment in the 25 kV switchyard is in poor condition. Both metalclad feeder sections have arc-flash hazards. Due to this safety concern, workers are restricted from entering the feeder section buildings while the equipment is energized; and
- In the last 10 years, the load has grown by approximately 1 per cent each year. In fiscal 2017, the actual demand was approximately 306 MVA.

Summarize Solution:

The strategy for this area is to mitigate the above reliability and safety risks while continuing to provide a reliable supply to the customers. BC Hydro has developed alternatives that upgrade the area supply in coordination with the need to retire major equipment approaching their end-of-life, and to address existing safety risks at Clayburn and Sumas Way substations. The coordination will avoid stranded investments in asset replacement projects to sustain the existing system. The solution alternatives consider a number of factors, including:

- The present capacity and future load growth in the area;
- The health of the assets at area substations, and their expected degradation over time;
- Opportunities to utilize capacity at neighboring substations;
- The timing of required projects at area substations combined with the need to retain adequate overall area capacity; and
- The need to develop the sequencing of projects in a way that minimizes/ avoids stranded investments that address issues in the existing substations.

For the Abbotsford area, the following strategy is being implemented:

Short- and Medium-Term:

- Expand Mount Lehman capacity from 100 MVA to 170 MVA;

- Address the safety risks associated with Clayburn by replacing the feeder section;
- The completion of the above will allow the transfer of load between stations:
  - Offload Clayburn load to Mount Lehman; and
  - Offload Sumas Way load to Clayburn; and
- Decommission Sumas Way.

Upon completion, there will have been a significant improvement in the overall equipment condition and reliability, the safety risks will have been mitigated, and the area will have sufficient capacity to accommodate future load growth in the area.

Long-Term:

In the longer-term, it is anticipated that a component by component replacement strategy will be undertaken at the different substations, to address risks with discrete assets as they degrade over time. In addition, growth in the area will continue to be monitored, to determine whether additional capacity is required.

Name of Capital Strategy, Plan or Study:
Barnard Asset Plan

Summarize Issue:

The 191 MVA Barnard substation is a transmission and distribution substation serving North Burnaby and portions of West Coquitlam and Port Moody. First commissioned in 1954, the substation consists of:

- Three switchyards: 230 kV, 69 kV, and 12 kV;
- Two power transformers; and
- Three feeder sections.

Barnard is an important substation given its dual role as both a transmission station and a distribution station. The station serves over 35,000 customers, and has the seventh largest peak load (133 MVA) in the Lower Mainland Metro region. Barnard provides one of the two transmission supplies to Lougheed substation and to six transmission voltage customer substations including Simon Fraser University.

Since commissioning in 1954, the substation has been expanded over time and there have been a number of investments in the past 20 years totalling over $15 million. Recent investments have included the addition of a new feeder section in 2008 and a project that is underway to replace all the circuit breakers in the 69 kV switchyard.

The most significant remaining issues and risks associated with Barnard substation include:

- One of the older feeder sections was designed to be compact in size and poses safety risks for workers due to limited clearance between energized equipment and ground. The risk is currently partially mitigated through physical barriers and warning signs;
- There are elevated reliability risks associated with the above-mentioned older feeder section due to the poor condition of 67 per cent of the 18 circuit breakers and 96 per cent of the 56 disconnect switches. The oil-filled circuit breakers in this feeder section also contain polychlorinated biphenyl (**PCB**) levels at or above 50 ppm which will be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline;
- There are elevated reliability risks associated with a second older feeder section and with the 230 kV switchyard, due to obsolescence issues with the original mechanical protection and control relays; and
- There are elevated reliability risks associated with the two relay buildings in the 69 kV switchyard. The buildings are in poor condition with cracking, leaking and seismic issues.

Summarize Solution:

The Barnard Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. The safety issues associated with the feeder sections of compact size will be addressed concurrently with equipment replacement projects. In the short and medium term, the focus will be on higher priority investments required for safe and reliable transmission and distribution of energy and to meet the requirements to phase out PCBs by the end of 2025. The longer-term activities are anticipated to focus on the remaining feeder sections and the transformers.

Short- and Medium-Term:

- Address the safety and reliability risks associated with the older feeder section that has high risk by replacing it with a new indoor feeder section;
- Address the reliability risks associated with protection and control equipment for the other older feeder section and the 230 kV switchyard by replacing the associated protection and control panels;
- Remove equipment with PCB levels at or above 50 ppm by the December 31, 2025 Federal Regulation deadline; and
- Replace the two relay buildings in the 69 kV switchyard as part of the 69 kV circuit breaker replacement project which is now underway.

Long-Term:

The equipment at the Barnard substation will continue to degrade over time, and a level of investment is anticipated in the longer term to preserve the reliability of the substation, and address emerging risks. Expected investments are required to address the risks associated with the remaining older feeder section as well as the transformers.

Name of Capital Strategy, Plan or Study:
Bridge River Transmission System Upgrade – Network Integrated Transmission Service Study

Summarize Issue:

The Bridge River area is located north of Pemberton. Generation in the Bridge River area is currently restricted as the Bridge River generating units have been de-rated due to degrading equipment condition. As BC Hydro invests in the generating units, transmission capacity may be exceeded creating system constraints during the summer period (June to July). With the increase in generation from the addition of IPPs and in concert with the existing BC Hydro facilities, there is a need to increase the capacity of the Bridge River regional transmission system to allow the delivery of full power during the summer months.

The main issues and risks include:

- Increase transmission capacity in the Bridge River area to meet the generation demands of the system;
- Reduce economic losses associated with generation curtailment;
- Provide reliable water conveyance capacity within the Bridge River system;
- Reduce the likelihood and magnitude of spills from Terzaghi Dam to Lower Bridge River; and
- Maintain BC Hydro's relationship with the St'at'imc Nation.

Summarize Solution:

The strategy is to provide sufficient transmission capacity to avoid the need for generation curtailment during summer months.

Short- and Medium-Term:

Alternatives that are being considered to deliver on this strategy include:

- Upgrading the 230 kV transmission line (2L90) between Bridge River Terminal and Kelly Lake;
- Expanding Rosedale substation; and
- Curtailing local generation.

Name of Capital Strategy, Plan or Study:
Asset Management Strategy - Section 2.2.2: Circuit Breakers

Summarize Issue:

There are 3,974 circuit breakers operating at voltages from 2.5 kV to 500 kV in BC Hydro's substations. A circuit breaker fulfills two roles: first, it acts as an automatically operated switch to protect an electric circuit from damage caused by high currents; second, circuit breakers are used by system operators to disconnect or connect different components of the electric system. Circuit breakers contain high pressure air, oil, vacuum or sulphur hexafluoride (**SF6**).

The general issues and risks associated with the failure of circuit breakers include:

- Reliability:
  - Elevated reliability risk if the circuit breaker does not operate as intended causing damage to other equipment in the circuit; and
  - Elevated reliability risk due to the sudden release of energy or fire impacting adjacent equipment.
- Environment:
  - Elevated risk of oil spills in the population of over 670 oil filled circuit breakers;
  - Elevated environmental and safety risk associated with SF6 leakage from the population of over 1,500 SF6 filled circuit breakers; and
  - Approximately 240 circuit breakers contain polychlorinated biphenyl (**PCB**) levels at or above 50 ppm which will be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline.
- Safety:
  - Elevated safety risk due to the sudden release of energy or fire; and
  - Elevated safety risk should a circuit remain live when it should otherwise be de-energized.

Over the last 10 years, BC Hydro has installed over 1,500 circuit breakers with two thirds being installed in the distribution substations and the balance on the transmission system.

Over 795 circuit breakers are currently over 40 years old, and approximately 622 (~16 per cent), of the circuit breakers have been assessed as Poor or Very Poor, indicating that there is an increased likelihood of failure.

Summarize Solution:

BC Hydro has developed a long term replacement strategy for circuit breakers to address the large number of aging circuit breakers and their associated risks. Historically the majority of work has focused on replacing circuit breakers on the 500 kV, 360 kV and 230 kV system. More recently the focus has shifted towards the lower voltage circuit breakers operating at 138 kV, 69 kV and lower. To address the issues and risks identified above, a number of approaches are taken, including:

- The replacement of circuit breakers will be included in the scope of work in a number of discrete capital projects. These projects will often address multiple issues at a substation, of which the circuit breakers are one element;
- Circuit breaker replacement programs will focus on remediating the risks associated with the highest priority circuit breakers at a large number of substations;
- A spares strategy will continue to be implemented to ensure that adequate spare breakers and parts are available to minimize the impact of failures; and
- Consideration has been given to opportunities to decommission assets where replacement is not necessary.

Short-Term:

Asset condition is reviewed on a regular basis considering factors such as recurring test results, visual inspections, and, detailed engineering assessments. This information is used to assess the risks related to each circuit breaker and to update a consolidated list with the intended timing of replacement investments.

Replacement projects that will occur in the short-term are described in the table below.

Upon completion of the work outlined in the table below, approximately 33 per cent of the 240 circuit breakers containing PCBs will have been removed from service. The replacement of theremaining 67 per cent will start and be completed in the medium-term ahead of the December 31, 2025 Federal deadline.

	Circuit breaker will be addressed as part of a larger project	**Projects where the circuit breaker is the primary driver**
Replacement projects that are underway and will be completed in the short-term	N/A	• Kelly Lake (1 x 500 kV) • Peace Canyon (1 x 500 kV)
Replacement projects that will start and will be completed in the short-term	N/A	• Atchelitz (7 x 69 kV) • Arnott (3 x 69 kV) • Babine Lake (1x 25 kV) • Barriere (1 x 25 kV) • Boston Bar (2 x 25 kV) • Cranbrook (6 x 69 kV) • Comox (1 x 25 kV) • Chetwynd (5 x 25 kV) • Dawson Creek (3 x 25 kV) • Dease Lake (1 x 25 kV) • Douglas Street (6 x 25 kV) • Fort St. John (3 x 25 kV) • Hundred Mile House (6 x 25 kV) • Horne Payne (4 x 12 kV) • Horne Payne (4 x 69 kV) • Horseshoe Bay (7 x 12 kV) • Horsey (20 x 12 kV) • Ingledow (2 x 12 kV) • Kent (6 x 12 kV) • Kidd No. 1 (7 x 12 kV) • Keating (1 x 25 kV) • Ladysmith (2 x 25 kV) • Minette (6 x 25 kV) • Newell (12 x 12 kV) • Suncor Energy (4 x 69 kV) • Port Kells (4 x 25 kV) • Puntledge (9 x 25 kV) • Parksville (5 x 25 kV) • Revelstoke (2 x 12 kV) • Skeena (1 x 12 kV) • Seton (3 x 69 kV)

		• Smithers (2 x 25 kV) • Steveston (3 x 25 kV) • Stewart (2 x 25 kV) • Tsawwassen (3 x 25 kV) • Vernon (3 x 25 kV) • Wahleach (2 x 69 kV) • Williams Lake (4 x 69 kV) • White Rock (5 x 25 kV)
Replacement projects that are underway and will continue into the medium-term	• Barnard (18 x 12 kV) • Mainwaring (18 x 12 kV) • Sperling (18 x 12 kV)	N/A
Replacement projects that will start in the short-term, and continue into the medium-term	• Kidd No. 1 (11 x 69 kV)	• Norgate (3 x 69 kV)

Medium- and Long-Term:

Considering the age and condition of the overall population of almost 4,000 assets, it is anticipated that a continued level of investment will be required. Replacement of the 12 kV, 25 kV and 69 kV circuit breakers will continue through the annual circuit breaker replacement programs. In addition, a number of discrete capital projects will address risks with the higher voltage circuit breakers, as part of their broader scope of work.

The goal is to manage the highest reliability, environmental and safety risks associated with circuit breakers. Approximately 20 per cent of the population is over 40 years old and will require remediation in the medium to long term as the assets move through their lifecycle. To pace these investments over time, approximately 100 units will need to be replaced on an annual basis, considering the design life of 35 to 40 years for circuit breakers. Factors such as age, condition and criticality will continue to be used for identifying the high priority units for replacement.

Name of Capital Strategy, Plan or Study:
Downtown Vancouver Electric Supply Plan

Summarize Issue:

The Downtown Vancouver study area is comprised of the Downtown, West End, Strathcona, and Grandview-Woodland neighborhoods. The area is supplied by a 230 kV and 69 kV transmission network and three substations:

- Cathedral Square substation which has a capacity of 302 MVA was built in 1984;
- Dal Grauer substation which has a capacity of 195 MVA was built in 1953; and
- Murrin substation which has a capacity of 200 MVA was built in 1947.

The study area contains the largest commercial center in Vancouver and has the highest load density in B.C. The area has approximately 95,000 customers and had a peak load of 411 MVA in fiscal 2017. The present area firm capacity is 697 MVA.

A number of investments have been made in this area in the past 20 years totaling over $300 million. Recent investments include the addition of a transformer and a feeder section at Cathedral Square in 2009 and the construction of a new 230 kV transmission cable circuit from Mount Pleasant to Cathedral Square in 2014.

The most significant issues and risks remaining in the Downtown Vancouver area include:

- There are elevated reliability risks at Dal Grauer and Murrin substation where more than half of the substation assets are expected to be in Poor or Very Poor condition within the next 10 to 20 years;
- Seven of the 11 transmission cable circuits supplying the three stations are expected to be in Poor or Very Poor condition within 20 years;
- More than half of the distribution cables at Dal Grauer and Murrin are expected to be in Poor or Very Poor condition within 20 years;
- The 12 kV equipment at Dal Grauer and Murrin substations exposes workers to safety risks due to limited clearance between energized equipment and ground. This risk is currently partially mitigated through physical barriers and warning signs;
- The indoor circuit breakers and exposed bus at Dal Grauer and Murrin substations expose workers to safety risks from potential arc flashes in the event of insulation failures; and
- Murrin substation is on seismically unstable soil. Approximately half of the 230 kV switchyard, which supplies both Murrin and Dal Grauer loads, is vulnerable to severe earthquake damage from liquefaction and settlement. All load being served from Dal Grauer and Murrin substations may experience a prolonged outage after a seismic event.

Summarize Solution:

The long term strategy for the area is to mitigate the above reliability and safety risks by replacing Murrin and Dal Grauer substations with new substations. The addition of the new substations will be timed to precede the need to retire major existing equipment as the assets approach their end-of-life. This means that new capabilities will need to be created, while older assets are still in-service, in anticipation of the decline in condition of a large population of assets. The sequencing of activities will need to be carefully planned and staged over the long-term, to minimize or avoid stranded investments in assets that may not be required in the long-term. The Downtown Vancouver Electricity Supply Plan examined three alternatives, each of which considered:

- The need to reduce seismic risk exposure;
- The health of each substation’s assets, and their expected degradation over time;
- The present area capacity and future load growth;
- Opportunities to transfer load to neighboring substations outside the study area;
- Opportunities to permanently decommission substations;
- The feasible timing of required work and the need to maintain sufficient area capacity;

- The costs of the different solutions;
- Performance and reliability requirements in the downtown area;
- Local stakeholder support; and
- Environmental impacts.

In light of the sizeable and complex issues noted above, the criticality of load in the downtown area, and the lead time required to build new substations in the Downtown Vancouver Area, it was particularly important to consider a long term planning horizon.

For the Downtown Vancouver Area the following strategy is being implemented:

Short- and Medium-Term:

- West End Substation:
  - Build a new underground 230/12-25 kV substation in the West End neighbourhood. This substation will have an ultimate capacity of 400 MVA; and
  - Build new 230 kV cable circuits to connect the new substation to the existing system.
- East Vancouver Substation:
  - Build a new indoor 230/12-25 kV, substation in the Strathcona neighbourhood. This substation will also have an ultimate capacity of 400 MVA.

Both of the substations above represent important infrastructure in critical locations that are anticipated to be in place for more than 50 years. The ultimate 800 MVA capacity of the two substations will not be installed immediately, but provides flexibility for growth over time, as the need for the load materializes.

Long-Term:

The activities outlined above have a relatively long lead time, and will enable a number of activities in the long-term:

- Offload the Dal Grauer substation to the West End substation;
- Offload the Murrin substation to the East Vancouver substation;
- Decommission the Dal Grauer and Murrin substations, as well as the 69 kV circuits;
- Replace the 230 kV cables that are in poor condition as required; and
- Add new 230 kV transmission circuits as required to meet future load growth.

Name of Capital Strategy, Plan or Study:
Kidd 1 Asset Plan

Summarize Issue:

The 100 MVA Kidd 1 substation is a transmission and distribution substation that serves Vancouver South. First commissioned in 1951, the substation consists of:

- Three switchyards: 69 kV, 12 kV and 4 kV;
- Four power transformers;
- Three feeder sections; and
- One 230 kV cable terminal.

Kidd 1 is an important substation given its dual role as both a transmission station and a distribution station. The station serves over 15,000 customers, and has the fifteenth largest peak load (69 MVA) in the Lower Mainland Metro region. Kidd 1 provides the primary transmission source for Big Bend substation and provides the only source of supply to the 69 kV switchyard at Sperling substation which in turn supplies the University of British Columbia. In addition, Kidd 1 supplies six transmission voltage customers and the distribution is adjoined by Sperling providing some flexibility to transfer load between the two substations.

Since commissioning in 1951, the substation has been expanded over time and there have been a number of investments in the past 20 years totaling over $35 million. Recent investments have included the replacement of two transformers and addition of a feeder section in 2014.

The most significant remaining issues and risks associated with Kidd 1 substation include:

- One power transformer is in Very Poor condition and has severe leaks;
- The two older feeder sections were designed to be compact in size and pose safety risks for workers due to limited clearance between energized equipment and ground. This risk is currently partially mitigated through physical barriers and warning signs;
- There are elevated reliability risks associated with the two older feeder sections, due to the poor condition of 86 per cent of the 28 circuit breakers, 100 per cent of the seven voltage regulators, 84 per cent of the 25 current limiting reactors and 92 per cent of the 103 disconnect switches. The oil-filled voltage regulators in these feeder sections also contain polychlorinated biphenyl (**PCB**) levels at or above 50 ppm which will be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline;
- There are elevated reliability risks associated with the 69 kV switchyard, due to the poor condition of 92 per cent of the 12 circuit breakers and 95 per cent of the 37 disconnect switches. The oil-filled circuit breakers also contain PCBs at levels above the allowable amounts, requiring phase out by the end of 2025; and
- There are elevated reliability and safety risks associated with the control building, due to the poor condition of 51 per cent of the 65 protection and control relays, the low seismic withstand capability of the building, and the presence of asbestos.

Summarize Solution:

The Kidd 1 Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. The safety issues associated with the compact sections of the substation will be addressed concurrently with the equipment replacement projects or by the decommissioning of the equipment. In the short and medium-term, the focus will be on higher priority investments required for safe and reliable transmission and distribution of energy and to meet the requirements to phase out PCBs by the end of 2025.

Short- and Medium-Term:

- Address reliability risk with the power transformers and one of the feeder sections by decommissioning the 4 kV switchyard and power transformers;
- Address reliability and safety risks associated with the other feeder section that poses the highest risk

and remove equipment with PCB levels at or above 50 ppm by the December 31, 2025 Federal Regulation deadline;

- Address reliability risks associated with the 69 kV switchyard and remove equipment with PCB levels at or above 50 ppm by the December 31, 2025 Federal Regulation deadline; and
- Address reliability risks associated with the control building.

Long-Term:

The equipment at the Kidd 1 substation will continue to degrade over time, and a level of investment is anticipated in the longer-term to preserve the reliability of the substation, and address emerging risks. Expected investments are required to address those risks associated with the remaining outdoor feeder section and the 69 kV switchyard that are not resolved in the short or medium term.

Name of Capital Strategy, Plan or Study: **Burrard Synchronous Condensers Replacement Study**
Summarize Issue: Burrard Thermal was a natural gas fired generating station with six 150 MW thermal generating units that were first put into operation in 1962. Since 2016, the Burrard facility has only operated as a synchronous condenser station. As a synchronous condenser station, Burrard is a major reactive power source in the Lower Mainland and is used to regulate system voltage under various system operating conditions. The facility is over 55 years old and approaching end of life which poses system reliability, environmental, and safety risks. The main issues and risks include: • The Burrard Synchronous Condensers (**BSY**) are at or approaching end of life. The four synchronous condenser units provide capacitive and reactive power to the transmission system. The capacitive and reactive power provides voltage control and prevents voltage instability during peak load periods; and • An assessment of the Fraser Valley transmission system has identified voltage stability constraints caused by reactive power losses.
Summarize Solution: BC Hydro is evaluating alternatives to address both issues summarized above. **Medium and Long-Term:** To ensure the capability currently provided by BSY is preserved, the alternatives listed below will be reviewed: • BSY reactive power function would be restored and additional capacitive power compensation would be installed in the Fraser Valley transmission system; or • Retire the BSY facility and add capacitive and reactive power requirements elsewhere in the BC Hydro Lower Mainland transmission system.

Name of Capital Strategy, Plan or Study:
Mainwaring Asset Plan

Summarize Issue:

The 211 MVA Mainwaring substation is a transmission and distribution substation serving Vancouver South. First commissioned in 1964, the substation consists of:

- Two switchyards: 230 kV and 12 kV;
- Three power transformers; and
- Two feeder sections.

Mainwaring is an important substation given its dual role as both a transmission station and a distribution station. The station serves over 60,000 customers, and has the fourth largest peak load (169 MVA) in the Lower Mainland Metro region. Mainwaring provides one of the two transmission supplies to Camosun substation. There is also flexibility to transfer the distribution load between the adjoining Newell and Mount Pleasant substations.

Since commissioning in 1964, the substation has been expanded over time and there have been a number of investments in the past 20 years totaling $25 million. Recent investments have included the addition of a new transformer in 2006 and replacement of the 230 kV circuit breakers in 2007 and 2011.

The most significant remaining issues and risks associated with Mainwaring substation include:

- One of the power transformers is in poor condition and is gassing. One other transformer has severe oil leaks. These do not have on-load tap changers, therefore voltage regulators in the feeder section are required to regulate the voltage;
- Both feeder sections were designed to be compact in size and pose safety risks for workers due to limited clearance between energized equipment and ground. The risk is currently partially mitigated through physical barriers and warning signs; and
- There are elevated reliability risks associated with both feeder sections, due to the poor condition of 39 per cent of the 46 circuit breakers, 80 per cent of the 38 voltage regulators, 51 per cent of the 41 current limiting reactors and 80 per cent of the 153 disconnects. The oil-filled voltage regulators and circuit breakers in these feeder sections also contain polychlorinated biphenyl (**PCB**) levels above the allowable amounts, requiring phase out by the end of 2025.

Summarize Solution:

The Mainwaring Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. The safety issues associated with the compact sections of the substation will be addressed concurrently with equipment replacement projects. In the short and medium term, the focus will be on higher priority investments required for safe and reliable transmission and distribution of energy and to meet the requirements to phase out PCBs by the end of 2025. The longer-term activities are anticipated to focus on the remaining equipment and the control building.

Short- and Medium-Term:

- Address reliability risk associated with two of the power transformers; and
- Address the safety and reliability risks associated with the two feeder sections and remove equipment with PCB levels at or above 50 ppm by the December 31, 2025 Federal Regulation deadline.

Long Term:

The equipment at the Mainwaring substation will continue to degrade over time, and a level of investment is anticipated in the longer term to preserve the reliability of the substation and address emerging risks, including those associated with the control building.

Name of Capital Strategy, Plan or Study: **Metro North Transmission Planning Report**
Summarize Issue: The Metro Vancouver (**Metro**) region includes BC Hydro's service areas in Vancouver, Burnaby, New Westminster, Richmond, and Coquitlam/Tri Cities. As a result of load growth in this region, a shortfall of supply capacity is anticipated within the next five years in the Metro North Transmission System which is part of the interconnected 230 kV transmission network that supplies the Metro region. This shortfall of transmission supply capacity would mean BC Hydro would not be able to supply the full demand of the Metro region during system normal winter peak load periods. Consequently, some load will need to be curtailed during winter peak load periods to avoid overloading and potentially damaging transmission equipment. The amount of required curtailment is anticipated to be up to 100 MW (equivalent to approximately 15 per cent of Downtown Vancouver). BC Hydro initiated the Metro North Transmission Project in 2013 to resolve the above shortfall of capacity with a planned October 2022 in-service date. The project has been put on hold while BC Hydro develops an updated load forecast which will confirm the timing of the constraints and the required project in-service date.
Summarize Solution: To address the above issue and avoid load curtailment, the following approaches have been identified: **Short-Term:** • Interim operational measures have been identified to resolve the transmission constraints. These measures are effective until fiscal 2025 and include: - Modifying the system configuration in real-time to divert the flow of electric power to alternative paths thereby reducing the amount of power flowing through the constrained circuits; and - Utilizing the overload capabilities/emergency ratings of transmission circuits, for a specified limited number of hours per year based on engineering studies. **Medium- and Long-Term:** • Construct a new 230 kV circuit between Meridian (**MDN**) and Horne Payne (**HPN**) substations, and extend an existing 230 kV circuit from HPN to Mount Pleasant Substation (**MPT**).

Name of Capital Strategy, Plan or Study:
Newell Asset Plan

Summarize Issue:

The 234 MVA Newell substation is a transmission and distribution substation that serves South Burnaby. First commissioned in 1955, the substation consists of:

- Three switchyards: 230 kV, 60 kV and 12 kV;
- Five power transformers; and
- Four feeder sections.

Newell is an important substation given its dual role as both a transmission station and a distribution station. The station serves over 50,000 customers, and has the third largest peak load (186 MVA) in the Lower Mainland Metro region. There is flexibility to transfer the distribution load between the adjoining Big Bend and Mainwaring substations.

Since commissioning in 1955, the substation has been expanded over time and there have been a number of investments in the past 20 years totalling over $25 million. Recent investments have included addition of a new feeder section in 2003 and replacement of the 230 kV circuit breakers in 2011.

The most significant remaining issues and risks associated with Newell substation include:

- One power transformer is in Poor condition, has severe oil leaks and contains polychlorinated biphenyl (**PCB**) levels at or above 50 ppm which will be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline;
- Three of the feeder sections were designed to be compact in size and pose safety risks for workers due to limited clearance between energized equipment and ground. This risk is currently partially mitigated through physical barriers and warning signs; and
- There are additional elevated reliability risks associated with two of the feeder sections, due to the poor condition of 62 per cent of the 29 circuit breakers, 95 per cent of the 37 voltage regulators and more than 60 per cent of the 220 disconnect switches. The oil-filled voltage regulators in these feeder sections also contain PCBs at levels above the allowable amounts, requiring phase out by the end of 2025.

Summarize Solution:

The Newell Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. The safety issues associated with the compact sections of the substation will be addressed concurrently with equipment replacement projects. In the short-term, the focus will be on higher priority investments required for safe and reliable transmission and distribution of energy and to meet the requirements to phase out PCBs by the end of 2025. The medium- to longer-term activities are anticipated to focus on the remaining feeder sections, substation security and the control building.

Short-Term:

- Address reliability risk with the power transformer and remove equipment with PCB levels at or above 50 ppm by the December 31, 2025 Federal Regulation deadline.

Medium-Term:

- Address the safety and reliability risks associated with the two feeder sections that pose the highest risks.

Long-Term:

- The equipment at the Newell substation will continue to degrade over time, and a level of investment is anticipated in the longer-term to preserve the reliability of the substation, and address emerging risks. Expected investments are required to address the risks associated with the two remaining feeder sections, to enhance the security of the substation, and also address risks associated with the degrading control building.

Name of Capital Strategy, Plan or Study:
Natal Asset Plan

Summarize Issue:

Natal substation is a transmission substation located in the Southern Interior region, near Sparwood, that consists of:

- Three switchyards: 230 kV, 138 kV and 60 kV; and
- Four power transformers.

The 60 kV and 138 kV switchyards were commissioned in 1968 and the 230 kV switchyard was commissioned in 1972. Natal is an important transmission substation given its role both as a bulk transmission substation and a source of supply for industrial customers. The station serves 10 industrial customers, providing over $20 million of revenue annually. Natal is also a point of intertie with the Alberta transmission system.

Since commissioning in 1968 the station has expanded over time and there have been a limited number of investments in the past 20 years totaling over $5 million. Recent investments have included replacement of surge arrestors in the 60 kV yard and circuit breakers in the 138 kV and 230 kV yards.

The most significant remaining issues and risks associated with Natal substation include:

- There are elevated reliability risks, due to the poor condition of 50 per cent of the four power transformers, both of the voltage regulators, 35 per cent of the 14 circuit breakers, 49 per cent of the 44 instrument transformers, as well as a significant proportion of the protection and control systems supporting the 60 kV and 138 kV switch yard;
- Many of the circuit breakers contain polychlorinated biphenyl (**PCB**) levels at or above 50 ppm which will be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline; and
- The 60 kV and 138 kV switchyards were designed and built to electrical clearance at the time, and pose safety risks for workers due to limited clearance between energized equipment and ground. This risk is currently partially mitigated through physical barriers and warning signs.

Summarize Solution:

The Natal Asset Plan presents a strategy to replace the 60 kV and 138 kV equipment. The safety issues associated with the substation will be addressed concurrently with the equipment replacement projects or by the decommissioning of the equipment. In the short-term, the focus will be on higher priority investments required for safe and reliable transmission of energy and to meet the requirements to phase out PCBs by the end of 2025.The medium to longer-term activities are anticipated to focus on sustain activities of the remaining equipment.

Short- and Medium-Term:

- A replacement of the 60 kV and 138 kV switchyards may be required to address the reliability, environment and safety risks of the 60 kV and 138 kV equipment. The scope of this work will include the power transformers, circuit breakers, instrument transformers, and protection and control systems. Consideration will also be given to the control building that houses the protection and control systems.

Long-Term:

- The equipment at the Natal substation will continue to degrade over time, and a level of investment is anticipated in the longer-term to preserve the reliability of the substation, and address emerging risks. Expected investments are required to address the risks associated with the 230 kV switchyard as it approaches poor asset health.

Name of Capital Strategy, Plan or Study:

Asset Management Strategy - Section 2.2.8: Oil Spill Containment

Summarize Issue:

Oil spill containment is an engineered asset, typically consisting of oil/water separators, tanks or pits, built in conjunction with oil containing equipment such as transformers, reactors or voltage regulators. These are used to collect oil that is accidently released from equipment and prevent contamination of the surrounding environment.

The general issues and risks associated with failure to contain an oil spill include:

- Environmental:
  - Contamination of land and water resources, and plant and animal species which can have long recovery times;
- Financial:
  - Costs associated with cleaning up areas affected by oil spills; and
  - Fines may be issued in the event of environmental damage; and
- Reputational:
  - Spills that threaten the environmental quality of water, land or air must be reported to the regulatory agencies and may damage BC Hydro's reputation with government and the public.

BC Hydro has over 1,000 pieces of oil-filled substation equipment which each contain more than 4,000 litres of oil. Approximately 60 per cent of these items do not have adequate oil spill containment.

Positive progress has been made to remediate these risks and over 400 oil containing pieces of equipment have new or upgraded oil containment.

Summarize Solution:

A risk assessment has been done at each of the substations containing those equipment items. Factors considered in the risk assessment include the quantity of oil on site, proximity to: aquatic resources, wildlife, species at risk, habitats, parkland, and First Nations land. The risk assessment also considers the water use in the area and the likelihood of a spill.

To address the issues and risks identified above, two approaches are used:

- Capital projects which install large oil containing equipment will also have oil containment installed; and
- An oil containment program which prioritizes upgrades of legacy substations that do not meet the current standard. This will address risks which are not otherwise addressed through a capital project.

Our strategies address these assets in two ways. First, we initiate projects that address multiple asset issues within a specific facility. When work is done as part of a project, the total duration of the project may exceed the two year test period. Second, we target specific oil containment issues as stand-alone items when this is the primary area of focus in a facility.

Short-Term:

Activities that will occur in the short-term are described in the table below.

	Oil spill containment that will be addressed as part of a larger project	Projects where oil spill containment is the primary driver
Containment activities that will be completed in the short-term	N/A	N/A
Containment activities that are underway, and will continue into the medium-term	• Bridge River 1 • Bridge River Terminal • Capilano • Hundred Mile House • Jordan River • Natal • Newell	• Atchelitz • Meridian
Containment activities that will start in the short-term, and continue into the medium-term	• Kelly Lake • Norgate • Patricia • Rosedale • Spillamacheen • Williston	N/A

Medium-Term:

The investments outlined above address the most pressing risks associated with oil spill containment. Many of the investments initiated in the short-term will continue to have capital expenditures and will go into service in the medium-term. The following substations are expected to have work initiated in the medium term:

- Nelway;
- Gold River;
- Balfour;
- Dal Grauer;
- Loughheed;
- Nakusp;
- Quesnel;
- Richmond;
- Scott Road;
- Sumas Way; and
- Surrey.

In the short- and medium-term this approach will reduce the risks associated with oil containment of another 10 per cent of equipment. This is an addition to the 40 per cent that already have adequate oil spill containment.

Long-Term:

In the long-term, work will continue to improve oil spill containment at a rate similar to the short and medium term and will be risk assessed and prioritized as outlined above.

Name of Capital Strategy, Plan or Study:
Patricia Asset Plan

Summarize Issue:

The 87 MVA Patricia substation is a distribution substation that serves Prince George. First commissioned in 1964, the substation consists of:

- Two switchyards: 60 kV and 12 kV;
- Three power transformers; and
- One feeder section.

Patricia is an important substation as it is the only distribution station supplying load to the downtown area of Prince George. The station serves over 14,000 customers making it the second largest substation by customer count in the Northern Interior region. The Patricia load cannot be served from the surrounding stations due to different distribution voltages (12 kV vs 25 kV).

Since being commissioned in 1964 the substation has been expanded over time and there have been a limited number of investments in the past 20 years totaling over $2 million. Investments have included replacements of a number circuit breakers and surge arresters in the 12 kV and 60 kV switchyards.

The most significant remaining issues and risks associated with Patricia substation include:

- The three power transformers were manufactured in the 1960s and do not have on-load tap changers, therefore voltage regulators are required to regulate the voltage. One of the power transformers is in poor condition;
- All 12 kV voltage regulators are in poor condition and contain polychlorinated biphenyl (**PCB**) levels at or above 50 ppm which will be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline;
- The 12 kV feeder section was designed to be compact in size and poses safety risks for workers due to limited clearance between energized equipment and ground. This risk is currently partially mitigated through physical barriers and warning signs; and
- Fourteen 12 kV bulk oil circuit breakers are in poor condition and contain PCB levels at or above 50 ppm which will be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline.

Summarize Solution:

The Patricia Asset Plan presents a strategy to replace assets on a component by component basis (i.e. undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. The safety issues associated with the compact section of the substation will be addressed concurrently with equipment replacement projects. In the short-term, the focus will be on higher priority investments required for safe and reliable distribution of energy and to meet the requirements to phase out PCBs by the end of 2025. The medium- to longer-term activities are anticipated to focus on the remaining feeder section issues and the control building.

Short- and Medium-Term:

- Replace the existing transformers. These will have on-load tap changers, enabling the removal of the voltage regulators in the feeder section;
- Remove all the voltage regulators containing PCBs; and
- Retrofit the 12 kV feeder section, replace all circuit breakers, disconnect switches, surge arresters and mitigate the electrical clearance issues.

Long-Term:

- The equipment at the Patricia substation will continue to degrade over time, and a level of investment is anticipated in the longer term to preserve the reliability of the substation, and address emerging risks. Expected investments are required to address the risks associated with the two station service transformers, and also address risks associated with the degrading control building.

Name of Capital Strategy, Plan or Study:
Peace to Kelly Lake 500 kV Transmission Reinforcement Study

Summarize Issue:

The Peace Region to Kelly Lake 500 kV system is used to transfer power from the Peace Region to the load centers. The capacity of the Peace to Kelly transmission system is limited by the voltage stability, transient stability, and the rating of the existing series capacitors. The Peace to Kelly transmission system is near capacity and generation additions in the Peace area (including Site C and future IPPs) will result in the transfer demand exceeding the transmission capacity.

The risk associated with the existing transmission system condition after 2024 is unable to transmit full generation capacity in the Peace Region to the load center during system normal and contingency conditions.

Summarize Solution:

To accommodate new generation in the Peace Region, transmission reinforcement is needed to continue reliable power delivery to the load centers. Increasing series compensation levels on the existing 500 kV transmission lines will increase transmission capability.

Short- and Medium-Term:

- Increase transmission capability to deliver the power generated in the Peace Region to the load centers by improving the utilization of the existing transmission assets, through a combination of reconfiguration of the existing series capacitor stations and building new series capacitor stations; and
- If load continues to grow in the Peace and North Coast regions, power flow south of Williston substation to the load center would decline. As a result, the scope of proposed reinforcements (south of Williston substation) would be scaled back by reducing the capacitor size of a new station and eliminating the reconfiguration of an existing capacitor station.

Name of Capital Strategy, Plan or Study:

Asset Management Strategy - Section 2.2.10: Shunt Reactors

Summarize Issue:

BC Hydro has 142 shunt reactors in its substations, the majority of which are 500 kV units. Shunt reactors are oil-filled and similar in construction to transformers. They are expensive substation assets with long lead times to acquire and replace. The majority of shunt reactors were installed from the 1960s to 1980s when most of the 500 kV transmission lines were built. Shunt reactors have two main purposes: firstly, they are used to help control the voltage on the transmission system under certain operating conditions and secondly they are used to protect the transmission cables from potential damage due to overvoltages.

The general issues and risks associated with the failure of shunt reactors include:

- Reliability:
  - Reduced transfer capability and increased network risks associated with the transmission system; and
  - Elevated transmission system voltages which can damage the transmission cables;
- Environmental:
  - Elevated risk of oil spills, particularly in locations with less robust spill containment and more sensitive environments; and
- Safety & Financial:
  - The increased likelihood of a fire poses a safety risk to workers, and may cause damage to surrounding assets.

Over the last 20 years, nine shunt reactors have been installed at eight substations. BC Hydro has also developed and implemented a spares strategy, and has purchased four reactors for 230 kV and 500 kV spares to minimize impacts of a failure. The total value of these investments was over $5 million.

Approximately 33 shunt reactors are between 40 and 50-years old and seven are more than 50-years old. Of the 142 shunt reactors, 41 (29 per cent) have been assessed as being in Poor or Very Poor asset health, indicating that they have an increased likelihood of failure.

Summarize Solution:

To address the issues and risks identified above, two general approaches are identified:

- Capital projects have been identified to remediate the risks associated with shunt reactors with the highest risk of failure. New units will be installed with oil spill containment; and
- A spares strategy will continue to ensure that critical spares are available to minimize the impact of shunt reactor failures.

Short-Term:

Condition of assets is reviewed on a regular basis considering such factors as recurring test results, visual inspections, and, where required, detailed engineering assessments. This information is used to assess the risk of failure of each reactor and to prepare a consolidated list across the system. The risk based list is used to identify the appropriate timing to replace individual reactors. Below is the list of those reactors with a highest priority for replacement.

Investments are recommended in the short term to replace these units:

- G.M. Shrum (six reactors).

Medium-Term:

The investments outlined above address the most pressing risks associated with the shunt reactors. A number of additional reactors will need to be addressed by future projects in the medium-term. The strategy and prioritization of risk reductions will be continually monitored over time as other shunt reactors degrade and the risk assessments are updated.

In the medium term, the following reactors have been identified as presenting higher risks:

- Williston (16 reactors); and

- Kelly Lake (six reactors).

Long-Term:

There are currently 33 shunt reactors between 40 to 50-years of age. Over the next 10 years, it is likely that a portion of these will degrade to poor or very poor condition. The risks associated with falling health of these assets will need to be addressed in the long term, following similar assessment and prioritization techniques to those outlined above.

Name of Capital Strategy, Plan or Study:

Integrated Planning Report for Capilano and Lynn Valley Substations and Distribution Area (2010) / Norgate Asset Plan

Summarize Issue:

North Vancouver is comprised of two municipalities, the City of North Vancouver and the District of North Vancouver. The area is bounded by the Capilano River to the west, the North Shore mountains to the north, Burrard Inlet to the south and Indian Arm to the east. There are approximately 60,000 customers in this area. The total load in 2017 was 203 MVA.

The City and District of North Vancouver and surrounding areas are supplied by five main substations, which together have a capacity of 331 MVA:

- North Vancouver has a capacity of 67 MVA and was built in 1950s;
- Lynn Valley has a capacity of 100 MVA and was built in the 1980s;
- Norgate has a capacity of 53 MVA and was built in the 1960s;
- Capilano has a capacity of 56 MVA and was built in the 1950s; and
- John Lawson has a capacity of 55 MVA and was built in the1950s.

Over the past 10 years there have been a number of investments undertaken to maintain and upgrade three of these stations, including, the addition of a new feeder section at Lynn Valley in 2013, a complete 12 kV rebuild of the North Vancouver substation in 2012, cable upgrades, additional feeder positions and a number of circuit breaker replacements at John Lawson between 2009 and 2016. At Capilano and Norgate substations, most of the assets are at the end of life and there are also some safety and other issues which need resolution.

The Capilano substation serves over 12,000 customers, and consists of:

- A 60 kV and a 12 kV switchyard;
- Two power transformers; and
- One feeder section.

The most significant issues and risks at the Capilano substation include:

- A significant portion of the equipment is in poor condition, including both of the 60 kV circuit breakers, 85 per cent of the 27 protection and control assets, 88 per cent of the 56 disconnect switches, and 50 per cent of the 42 the instrument transformers;
- A number of the circuit breakers are obsolete, unreliable and contain oil with polychlorinated biphenyl (**PCB**) levels at or above 50 ppm which will be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline; and
- The existing feeder section building does not meet current seismic standards and equipment has limited clearance between energized equipment and ground. The risk is currently partially mitigated through physical barriers and warning signs.

The Norgate substation serves over 5,000 customers, and consists of :

- A 60 kV and a 12 kV switchyard;
- Three power transformers; and
- One feeder section.

The most significant remaining main issues and risks at Norgate substation include:

- All three power transformers are in poor condition and subject to oil leaks;
- All of the voltage regulators in the feeder section are in poor condition and contain PCBs at levels at or above 50 ppm which will be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline;
- The majority of the remaining substation assets are also in poor condition including: 42 per cent of the 17 circuit breakers, 64 per cent of the 11 reactors, 94 per cent of the 31 protection and control assets, and 87 per cent of the 52 disconnect switches; and

- The feeder section has worker safety issues related to limited clearance between energized equipment and ground. The risk is currently partially mitigated through physical barriers and warning signs which create access restrictions during maintenance and operations.

Summarize Solution:

Performing work at these substations is complex. Space is often limited, meaning that workers have to work in close proximity to the energized equipment when the major construction needs to be done to replace/add the equipment. To continue to supply the load to the customers during construction, the new equipment and infrastructure has to be added before it is possible to take existing equipment out of service since there is a limited capacity to transfer the load elsewhere to the neighboring stations. Creating space within the substations is sometimes challenging and at times requires expansion of the substation footprint.

The strategy for the area is intended to sequence work in such a way that the issues and risks outlined above are mitigated, while continuing to provide reliable supply to customers. The development of a strategy for the area will consider a number of factors, including:

- The current capacity and projected growth for the area;
- The condition of the assets at different area substations, and their expected degradation over time;
- The sequencing and timing of required sustainment work at area substations combined with the need to manage overall area capacity;
- Minimize/ avoid stranded investment in the area substations by optimizing the planning and the staging of work; and
- Opportunities to utilize capacity at neighboring substations.

Short- and Medium-Term:

- The Capilano substation will be completely rebuilt with a capacity of 100 MVA.
  - A new substation will be built within the footprint of the existing substation fence;
  - The load from the existing 56 MVA substation will be transferred to the new substation; and
  - The existing 56 MVA substation will be decommissioned.
- For Norgate substation, alternatives are being examined to address the ageing assets, safety risks and other specific issues outlined above. The alternatives will include:
  - Replace or refurbish the transformers and 12 kV feeder section; and
  - Transfer the load to the neighboring stations and decommission the transformers and the feeder section.

When all the above investments are completed there will be significant improvements in the overall equipment condition and reliability. The safety and seismic risks will be mitigated and PCBs will have been removed ahead of the end of 2025 Federal deadline. The area will have the necessary capacity to accommodate the future growth in the area.

Long-Term:

In the longer-term, it is anticipated that a component by component replacement strategy will be undertaken at the different substations to address risks with discrete assets as they degrade over time.

Name of Capital Strategy, Plan or Study:
Sperling Asset Plan

Summarize Issue:

The 214 MVA Sperling substation is a transmission and distribution substation that serves Vancouver West. First commissioned in the 1940s, the substation consists of:

- Three switchyards: 230 kV, 69 kV and 12 kV;
- Two power transformers; and
- Four feeder sections.

Sperling is an important substation given its dual role as both a transmission station and a distribution station. The station serves over 55,000 customers, and has the fifth largest peak load (166 MVA) in the Lower Mainland Metro region. Sperling substation is the only source of supply to the University of British Columbia and one of the two supplies to Camosun substation. There is also flexibility to transfer the distribution load between the adjoining Camosun, Mount Pleasant and Kidd 1 substations.

Since commissioning in the 1940s, the substation has been expanded over time and there have been a number of investments in the past 20 years totaling over $30-million. Recent investments have included the addition of a new indoor feeder section in 2009 and the replacement of the circuit breakers in an older indoor feeder section in 2012.

The most significant remaining issues and risks associated with Sperling substation include:

- The two outdoor feeder sections were designed to be compact in size and pose safety risks for workers due to limited clearance between energized equipment and ground. This risk is currently partially mitigated through physical barriers and warning signs;
- There are elevated reliability risks associated with one of the outdoor feeder sections and transformer circuit breakers, due to the poor condition of 90 per cent of the 10 circuit breakers, and 93 per cent of the 56 disconnect switches. The oil-filled circuit breakers in these feeder sections also contain polychlorinated biphenyl (**PCB**) levels at or above 50 ppm which will be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline;
- All eight indoor transformer circuit breakers pose safety risks for workers due to the potential for arc flash hazards in the event of failures; and
- There are elevated reliability risks associated with the 69 kV switchyard due to the poor condition of 92 per cent of the 13 disconnect switches, and obsolescence issues with the original mechanical protection and control relays.

Summarize Solution:

The Sperling Asset Plan presents a strategy to replace assets on a component by component basis (i.e., undertake discrete investments as needed), considering factors such as condition, rate of deterioration, the operating environment, and criticality. The safety issues associated with the two feeder sections of compact size will be addressed concurrently with other equipment replacement projects. In the short- and medium-term, the focus will be on higher priority investments required for safe and reliable transmission and distribution of energy and to meet the requirements to phase out PCBs by the end of 2025.

Short- and Medium-Term:

- Address the safety and reliability risks associated with one of the outdoor feeder sections and the bus breakers by replacing them with a new indoor feeder section in a new building;
- Remove equipment with PCB levels at or above 50 ppm by the December 31, 2025 Federal Regulation deadline; and
- Address the reliability risk associated with the 69 kV switchyard by decommissioning the switchyard and control building at Sperling after transferring the load to the adjoining Camosun substation.

Long-Term:

The equipment at the Sperling substation will continue to degrade over time, and a level of investment is anticipated in the longer term to preserve the reliability of the substation, and address emerging risks. Expected investments are required to address the risks associate with the remaining outdoor feeder section and transformers that were installed in the 1970s.

[redacted]

[redacted]

Name of Capital Strategy, Plan or Study:
Asset Management Strategy - Section 2.2.15: Synchronous Condensers

Summarize Issue:

There are eight synchronous condensers on the BC Hydro system all of which are over 40-years old. Four are located at Burrard Synchronous Condenser Station, three are at Vancouver Island Terminal and one is at Kelly Lake Substation. They are expensive assets with long lead times to acquire and replace. Synchronous condensers are rotating machines that are similar to generators. Each machine has a number of supporting systems, including a gas handling system, an excitation system, and a protection & control system. These assets are used to provide system voltage control and contribute to the system stability.

This strategy focuses on the four synchronous condensers at Vancouver Island Terminal and Kelly Lake substation as the future use of synchronous condensers at Burrard is presently under review.

The main issues and risks with the synchronous condensers are:

- Safety - There are fire risks associated with leaks in the hydrogen gas handling systems; and
- Reliability - The excitation and the protection and control systems are aging, with increased likelihood of failure. There are obsolescence issues and spare parts can be challenging to source given that manufacturer support is limited. These issues can result in long downtimes if a unit is forced out of service.

Over the last 10 years, refurbishment of the windings and internal components of each of the four machines has been completed. BC Hydro also developed and implemented a spares strategy, and made additional investments in spare parts to minimize outage time in the event of failures. To help with troubleshooting, BC Hydro increased the use of on-board diagnostics and implemented a knowledge transfer process to enhance its repair capability in the field. The total value of these investments was over $26 million.

As a result of this work, the overall condition of the assets at Vancouver Island Terminal and Kelly Lake has been improved. However, reliability and safety risks remain with specific supporting systems, such as gas handling, excitation and protection and control.

Summarize Solution:

To address these issues and risks, the following approaches will be taken:

- Capital projects will upgrade the gas handling, excitation, and the protection and control subsystems of each unit;
- A spares strategy will ensure that critical parts are available to facilitate breakdown repairs and shorter outages; and
- Increased use of on-board diagnostics to shorten outages.

Short-Term:

Investments will begin in the short-term with projects for each of the four synchronous condensers to focus on addressing the remaining risks in the support systems, namely the gas handling system, excitation system, and the protection and control system.

Medium- and Long-Term:

Given that the assets at Vancouver Island Terminal and Kelly Lake are over 40-years old, a level of ongoing work will be required as the assets progress through their lifecycle and risks associated with falling health of these assets will need to be addressed.

Name of Capital Strategy, Plan or Study: **Transmission Planning Study for the Peace Region Electric Supply Project**
Summarize Issue: The Peace region is experiencing significant load growth especially in the Dawson Creek and Groundbirch areas, mainly driven by the gas industry. The regional transmission system has already exceeded its supply capability to reliably serve the community of Dawson Creek and existing industrial customers in the region. The regional transmission system has also reached its normal system supply limit, and as a result no new industrial customers can be interconnected to BC Hydro's system. The Dawson Creek / Chetwynd Area Transmission (**DCAT**) project, which went into service in late 2015, resolved the initial constraints in the transmission system supplying the area, but a second project, the Peace Region Electricity Supply (**PRES**) project, is required to supply (firm supply) the forecasted load over the next 30 years. A load shedding scheme was implemented which will automatically interrupt power service to industrial load customers in the event of a transmission outage until PRES is implemented. The risks associated with the current system condition are: • New Loads: Not being able to supply any new industrial loads in Dawson Creek and Groundbirch areas; and • Exiting Loads: Not being able to supply the existing load under single contingency on the system.
Summarize Solution: The PRES project is required at the earliest in service date to ensure the availability of capacity on the transmission system to serve new customers in the region. Seven alternatives were identified to resolve the supply constraints within the Peace region system. The leading alternative (construct a new double circuit 230 kV line from Southbank switching station (**SBK**) to Shell Groundbirch substation (**SGB**)) was selected by evaluating factors such as load supply capability, system reliability, capital costs of construction, operating and maintenance costs and transmission system losses. **Short-Term:** • Provide reliable supply for the existing loads (transmission and distribution); • Avoid load shedding; • Avoid dispatching of the customer owned generators to minimize operating costs; and • Serve new customers in the region. **Medium-Term:** • Electrify new or existing oil and gas loads (gas compression) in the Peace region; and • Reduce greenhouse gas emissions by electrification of industrial loads and reducing customer owned generation. **Long-Term:** • Provide supply capability for future load growth (transmission and distribution).

Name of Capital Strategy, Plan or Study:
Asset Management Strategy - Section 2.1.2: Conductors

Summarize Issue:

BC Hydro has approximately 19,300 circuit-km of overhead transmission conductors. The average age of conductors on the transmission system is 45 years. The objective of the conductor strategy is to achieve a life of 80 years for transmission circuits while operating at design load capacity.

Overall, conductor condition is determined by regular inspections and failure analysis. Systematic sampling is also used for analytical condition assessments, by removing short segments of conductor for laboratory testing. When defects are identified, capital projects are initiated considering an integrated approach, and factoring in the nature of the defect, site conditions, overall condition of the line and system needs.

Overhead transmission line conductors can be classified in two main types: aluminum conductor steel-reinforced (**ACSR**), which is the industry standard and comprises the majority of installed conductors; and copper (**Cu**), which is obsolete for use as conductor. There are some exceptions where other types of conductor are used on the transmission system: for example all-aluminum conductor (**AAC**), all-steel conductor (**ASC**), and aluminum conductor - carbon fibre core (**ACCC**).

Copper conductors have largely been replaced with ACSR; approximately 300 circuit km of copper conductor remain in the BC Hydro Transmission system. Since fiscal 2010, approximately 150 km of copper conductor has been replaced, including recent projects for circuits 60L02, 60L03, 60L18, and 60L19.

The risks and issues associated with overhead conductors include:

- Condition – Degradation can occur from age and stresses such as wind, ice, lightning, thermal loading, corrosion, mechanical damage and air pollution;
- Safety & Reliability – Failures due to degradation can create public and worker hazards and result in forced outages with long restoration times; and
- Capacity – Degradation of the conductor can lead to de-rating of the circuit.

Summarize Solution:

To address the above issues and risks, the following staging of investments is recommended:

Short-Term:

- Continue to maintain and prioritize conductor replacements and upratings based on condition;
- Manage operation overload limits to avoid conductor damage;
- Continue with the Copper conductor replacements planned for circuits 60L004, 60L011, and 60L054 on the south side of Burrard Inlet around Burnaby Mountain.
- Initiate a conductor sampling program for ACSR conductor; and
- Address the end-of-life conductor issues at Jervis Inlet Crossing.

Medium- and Long-Term:

- Continue Copper Conductor Replacement Program; and
- Continue the ACSR conductor sampling program to identify scope for future overhead conductor replacement capital program.

Name of Capital Strategy, Plan or Study:
Asset Management Strategy - Section 2.1.10: Transmission Cables

Summarize Issue:

The major objective of the strategy is to achieve a life of 55 years for transmission cable systems, which is 15 years longer than the life stated by cable manufacturers, by targeted upgrades and refurbishments. BC Hydro has approximately 350 km of transmission cables, of which 196 km are submarine with the remainder being underground in mostly the Greater Victoria and Metro Vancouver areas. Cables are used to transfer electricity where it would be difficult or impractical to install overhead transmission lines, such as across large bodies of water or through cities where tall buildings or high density make it impossible. A cable system is comprised of a cable, duct banks, manholes, and ancillary equipment (such as pressurization and monitoring systems). There are two broad categories of cables: self-contained fluid-filled (**SCFF**) which uses paper and oil for insulation, and cross-linked polyethylene (**XLPE**), which instead uses a form of plastic and is oil-free.

The main issues and risks associated with transmission cables include:

- Capacity - Historic growth can result in the need to operate existing cables closer to their maximum electrical rating which can result in higher temperatures and reduced life spans;
- Security - Terminal structures where the cables connect to overhead lines are vulnerable to vandalism, particularly by copper thieves;
- Reliability - Cables are essential for service for reliable transfer of electricity. Failed cables leading to forced outages may cause localized load shedding and impact system reliability significantly. Repairs take a long time and leave the system in a vulnerable state; and
- Environmental - Fluid-filled cables can leak oil which can result in adverse environmental impacts. The risk of leaks increases with age as the cable’s outer metallic layer (which acts to contain the oil) fatigues.

Recent projects have included installing temperature monitoring systems on the 230 kV cables in Vancouver to ensure the transmission cables are not overloaded and to gauge overall health. Installation of pressure monitoring systems to provide early warning of any leaks has also been completed. Additional spare cables have been purchased to reduce response times if cables are damaged.

Summarize Solution:

To address the above issues and risks, the following staging of investments is recommended:

Short-Term:

- Continue with maintenance and inspection programs;
- Replace the cable (2L146) between the Goward and Horsey substations;
- Gulf Islands - Transmission Reinforcement Project; and
- Refurbish pumping equipment to maintain and extend service life of fluid-filled cable systems.

Medium-Term:

- Expand use of temperature monitoring systems to measure cable temperature and adopt dynamic rating systems to allow for higher power transfers (by running closer to thermal limits) and defer cable replacements that may be required by growth needs.

Long-Term:

- Consider the replacement of the 138 kV submarine cable that supplies the Gulf Islands and Vancouver Island; and
- Continue practice of installing solid-dielectric insulated cables to eventually phase out use of oil-filled transmission cables to mitigate potential environmental risk.

Name of Capital Strategy, Plan or Study:

Asset Management Strategy – Section 2.4.1 and 2.4.2: Fibre Optic and Microwave Equipment

Summarize Issue:

The BC Hydro fibre optic system has a total of 272 assets connecting 71 substations, and the microwave system has a total of 1388 assets at 152 different locations around the province. The microwave and fibre optic elements of the telecommunications system work together to enable high-speed clearing of transmission system faults, system protection, and Supervisory Control and Data Acquisition (**SCADA**) linking the major stations with the Control Centre. The Telecommunications system also provides a dedicated communications system available in emergencies and is a key element in meeting WECC/NERC reliability standards.

In addition to telecom system growth required to connect new substations, major load customers, and generation interconnections, in the past three years, critical SCADA and Energy Management System traffic has begun to be transferred from the old failing assets onto new network equipment. Replacement models for microwave radios and digital cross connect systems have been identified and accepted for use in the system. Some failing microwave radio equipment has been replaced with new equipment, and a number of failed multiplexors have been replaced.

The main issues and risks associated with the fibre optic and microwave equipment include:

- The main telecommunications equipment components of the system are degrading and are no longer supported by the manufacturer. These include the microwave radios, multiplexors, and digital cross connects;
- Some of the sites have local environmental conditions that affect operation; and
- Growth of the power system requires telecommunication upgrades at certain locations.

Summarize Solution:

Projects are planned for the sustainment of the microwave and fibre optic system by balancing asset condition and criticality.

To address the above issues and risks, the following staging of investments is recommended:

Short-Term:

Specific regional issues exist with some systems where growth has occurred, requirements have changed, environmental and/or situational conditions have lead to short-term project needs.

The projects planned in the short-term include:

- Address icing issue at the Copper Mountain microwave tower and replace the building;
- Upgrade the telecommunications system at Natal substation;
- Replace the telecommunications equipment on Vancouver Island; and
- Replace the Digital Cross Connect System equipment across the province.

Medium-Term:

The microwave radios are degrading and require replacement across the majority of the system. Additionally, the plan addresses some key microwave sites in the Fraser Valley that are dependent on a single physical point of failure.

The projects in the medium term include:

- A replacement of the microwave radios and multiplexors across the province; and
- A project to address single points of failure of the microwave system in the Fraser Valley.

Long-Term:

In the long-term, the microwave system includes sites that are single physical point of failure and projects are planned to address mitigating the risk of significant events such as forest fire or land slides.

Name of Capital Strategy, Plan or Study:
Asset Management Strategy – Section 2.4.4: Protection and Control Equipment

Summarize Issue:

Protection and Control (**P&C**) assets include a wide range of electrical devices that protect transmission equipment from damage, ensure reliability and stability of the transmission system, and provide local and remote operational visibility and control of transmission lines, station equipment, and the BC Hydro power system as a whole. P&C equipment includes devices such as protective relays, control modules, alarm systems, electrical meters, and local and remote supervisory control and data acquisition system remote terminal units (**SCADA RTUs**).

Protection assets and systems are used to detect abnormal voltage and current conditions and automatically make response decisions about de-energizing and isolating a piece of equipment or portion of the system. These systems are also subject to evolving Mandatory Reliability Standards as defined by North American Electric Reliability Corporation (**NERC**) and regulated by the BCUC.

Over the past five years a considerable amount of work has been undertaken to address the issues with P&C assets:

- Complete station P&C upgrades have been completed at: Arnott, Atchelitz, Barnard, Cambie, Campbell River, Como Lake, Camosun, Douglas, Lake Cowichan, McLellan, Newell, Northfield, Nicomekl, Port Hardy, Port McNeill, Sooke, Strawberry Hill, Steveston and White Rock;
- Digital Fault Recorders (**DFRs**) have been replaced at: Ashton Creek, Cranbrook, G.M. Shrum, Ingledow, Kootenay Canal, Kelly Lake and Nicola;
- SCADA RTUs have been replaced at American Creek, Armstrong, Babine Lake, Balfour, Barriere, Buckley Bay, Bridge River Terminal, Beaverley, Cranbrook, Cheekye, Coquitlam, Cathedral Square, Chevron, Fort St. John, Fernie, Forest View, George Dickie, Joeseph Creek, Kalum, Kenedy, Kicking Horse, Meridian, Malaspina, Portage Pass, Pineview, Rosedale, Rupert, Ruby Creek, Richmond, Selkirk, Shell Groundbirch, Skeena, Sundance Lakes, Surrey, and Sorrento;
- Programmable Logic Controllers have been replaced at Ingledow and Meridian;
- Full station controls modernization upgrades are underway at Williston and G.M. Shrum; and
- A portion of the protection relays have been replaced at Clayburn, Kidd 2, Lougheed, Sperling, Gloucester, Silverdale, Salmon Arm, Long Beach, Mission, Meridian, Murrin and Williams Lake.

The main issues and risks associated with P&C equipment include:

- DFRs and certain models of SCADA RTUs across the system are at end of life and no longer supported by the vendors;
- NERC Critical Infrastructure Protection (**CIP**) five mandatory reliability standards are an immediate requirement where BC Hydro was required to achieve initial compliance by October 1, 2018 and implement systems to maintain that compliance into the future; and
- Control systems are at end-of-life.

Summarize Solution:

Projects are planned for the sustainment of the P&C system assets by considering asset condition and their criticality in meeting the power system reliability and safety. To address the above issues and risk the following staging of investments is recommended:

Short-Term:

- Address the most critical elements of the P&C system including:
  - Replace the SCADA RTUs at the following stations: Walters, Dal Grauer, Texada Island East and West, Texada Island Reactor, Cape Cockburn, Nile Creek, Murrin and Kidd 2; and
  - Replace the DFRs at the following stations: Peace Canyon, Selkirk, Cheekye, Revelstoke, Arnott and Vancouver Island Terminal;
- Specific local issues exist where entire station control assets are at end of life and need to be refreshed. These stations are: Ingledow, Williston, G.M. Shrum, and the American Creek Capacitor

station; and

NERC CIP 5 mandatory reliability standards are also an immediate requirement, and BC Hydro achieved initial compliance October 1, 2018 and needs to implement systems to sustain compliance in the medium impact transmission stations.

Medium- and Long-Term:

- Replacement of end of life P&C assets will continue with a focus on the highest risk assets including legacy models of protection relays, SCADA RTUs, and DFRs. This includes the DFRs at the Dunsmuir and Malaspina stations and the RTUs at Burrard, Savona, Sechelt, Comox and Harewood;
- Comply with the next generation of Mandatory Reliability Standards, particularly NERC CIP 7; and
- In the long-term, the P&C systems will need to be modernized to align with industry advances that bring additional safety, reliability and operational cost benefits.

Name of Capital Strategy, Plan or Study:
Asset Management Strategy - Section 2.2.16: Power Transformers

Summarize Issue:

There are 572 power transformers with a voltage class of 60 kV or greater at BC Hydro substations. Transformers are one of the most critical and expensive assets in a substation, and have long lead times to acquire and replace. Transformers fulfill multiple roles. Firstly, power transformers are used to increase the voltage to a level that can be transmitted over long distances via the transmission network. Secondly, in the transmission network, transformers are used to connect systems that are operated at different voltages. Finally, transformers are used to reduce transmission voltages to a lower level that can be distributed to customers.

The general issues and risks associated with a failure of a power transformer include:

- Reliability:
  - Elevated risk of customer outages at single transformer distribution substations, and a loss of redundancy at multi transformer distribution substations; and
  - Reduced transfer capability and increased network risks associated with the transmission system;
- Environment:
  - Elevated risk of oil spills, particularly in older transformers with less robust oil spill containment; and
- Safety & Financial:
  - The increased likelihood of a fire poses a safety risk to workers, and may cause damage to surrounding assets.

Over the last 10 years, 80 transformers have been installed at 55 substations. BC Hydro has also developed and implemented a spares strategy, and has purchased 10 new spare transformers of different ratings to minimize impacts in the event of a failure. The total value of these investments was over $400 million.

Approximately 87 transformers are between 50 and 60-years old, and 36 are more than 60-years old. Approximately 121 (21 per cent) of the total power transformers have been assessed as Poor or Very Poor, indicating that there is an increased likelihood of failure.

Summarize Solution:

To address the issues and risks identified above, a number of approaches have been taken, including:

- Capital projects have been identified to remediate the risks associated with some of the transformers;
- A spares strategy will continue to be implemented, as necessary, to ensure that critical spares are available to minimize the impacts of a transformer failure; and
- Consideration has been given to opportunities to decommission assets where replacement is not necessary.

Our strategies address these assets in two ways. First, we have initiated projects that address multiple asset issues with a specific facility. When work is done as part of a project, the total duration of the project may exceed the two year test period. Second, we target specific transformers as stand-alone items when this is the primary area of focus in a facility.

Short-Term:

Condition of assets are reviewed on a regular basis considering such factors as recurring test results, visual inspections, and, where required, detailed engineering assessments. This information is used to assess the risk of failure of each transformer to help prepare a consolidated list across the fleet to identify the timing to address the risks.

Activities that will occur in the short-term are described in the table below.

	Transformers that will be addressed as part of a larger project	Projects where the transformer is the primary driver
Activities that will be completed in the short-term	N/A	N/A
Activities that are underway, and will continue into the medium-term	• Capilano (60/12 kV) • Kidd 1 (60/4 kV) • Mainwaring (230/12 kV) • Mount Lehman (230/25 kV) • Natal (138/60 kV) • Newell (230/12 kV)	• Bridge River 1 (60/238 kV) • Bridge River Terminal (345/238 kV) • Hundred Mile House (60/238 kV) • Jordan River (13/25/138 kV)
Activities that will start in the short-term, and continue into the medium term	• Norgate (60/12 kV) • Patricia (60/12 kV) • Pemberton (230/25 kV) • Rosedale (345/238 kV)	N/A

Medium-Term:

The investments outlined above address the most pressing risks associated with the transformers. Many of the investments initiated in the short-term will continue to have capital expenditures and will go into service in the medium-term.

The following is a list of assets that are expected to be initiated in the medium-term. The strategy and prioritization will be continually monitored over time as other assets degrade. In the medium term, transformers at the following substations have been identified as higher risk:

- Balfour (60/12 kV);
- Coquitlam (60/12 kV);
- Dal Grauer (60/12 kV);
- Glenmore (60/4 kV);
- Horne Payne (230/12 kV);
- Loughheed (60/12 kV);
- Nakusp (60/12 kV);
- Quesnel (60/12 kV);
- Richmond (60/12 kV);
- Scott Road (60/12 kV);
- Sumas Way (60/25 kV);
- Surrey (60/12 kV); and
- Wahleach (345/13 kV).

Long-Term:

There are approximately 164 transformers between 40 to 50-years of age. Over the next 10 years, it is likely that a portion of these will degrade to poor or very poor condition. Remediation of the risks associated with these degrading assets will be required in the long-term, applying similar assessment and prioritization techniques to those outlined above.

Name of Capital Strategy, Plan or Study:
West Kelowna Area Study

Summarize Issue:

The 138/25kV Westbank Substation (**WBK**) supplies the West Kelowna area and is connected only to Nicola Substation (**NIC**) by a single 80-km long radial 138 kV transmission line. WBK has no ties to any other substations and there is no local generation to serve the load in the area. Consequently, if the radial transmission line is out of service, the 22,000 customers in the West Kelowna area will experience an outage. The geographic area of the transmission line has been subjected to wildfires in past summers.

In addition, there is a need to increase the station capacity at WBK. The station has three 138 kV/25 kV transformers with a summer firm capacity of 80 MVA (assumes the loss of a transformer). Firm capacity was exceeded by 15 per cent in fiscal 2019 by the summer load demand.

Also, some equipment that has been in-service since the early 1970s is nearing end-of-life and needs replacement.

Summarize Solution

BC Hydro is evaluating alternatives to address the above issues with an integrated approach.

Short- and Medium-Term:

- Two alternatives are being considered to mitigate natural hazard risks to the West Kelowna transmission system:
  - Build a new, secondary transmission line to WBK to improve the reliability of supply and supply future load growth; and
  - Improve the resiliency of the existing transmission line to minimize the risk of outages resulting from forest fires and geotechnical events.
- Westbank Upgrade Project:
  - Increase the WBK summer firm capacity from 80 MVA to 120 MVA by replacing an existing 28 MVA transformer with a 75 MVA unit and replace end-of-life assets; and
  - Provide for the addition of a new feeder section which may be required to accommodate future load growth.

Name of Capital Strategy, Plan or Study:
Wood Pole Substation Strategy

Summarize Issue:

There are 50 substations that have been classified as Wood Pole substations for asset management and planning purposes. Collectively, all of these substations serve approximately 75,000 customers. Their common characteristics generally include:

- Individually, these are small distribution stations, the majority of which have a load of less than 15 MVA and serve less than 3,000 customers;
- Usually located in remote rural locations, often at the end of a radial line;
- A wooden structure which is used to mount electrical equipment such as disconnect switches;
- A single power transformer;
- A small number of feeder positions (usually less than four);
- No control room; and
- Mobile transformers are required in the event of a failure.

The general issues and risks associated with Wood Pole substations include:

- Reliability:
  - The poor condition of the wooden structures represents an elevated reliability risk. The wooden cross members in the wooden box structure can sag over time, physically contacting nearby equipment, and causing customer outages; and
  - The poor condition of equipment such as transformers, disconnect switches and voltage regulators represents an elevated reliability risk. Limited redundancy in these substations means that a failure of any one component has a high likelihood of causing a total outage of the station;
- Safety:
  - The degrading condition of the wooden structure represents a safety hazard to workers inside the substation; and
  - The compact size poses safety risks for workers due to limited clearance between energized equipment and ground. This risk is currently partially mitigated through physical barriers and warning signs;
- Environmental:
  - Much of the oil filled equipment in wood pole substations contains polychlorinated biphenyl (**PCB**) levels at or above 50 ppm which will be proactively replaced by the December 31, 2025 Federal PCB Regulation deadline.

Over the last 20 years, approximately $60 million has been invested in addressing the most pressing risks at 12 of the 50 Wood Pole substations. Work at another three of these is also currently underway. BC Hydro has also invested in mobile transformers to act as emergency replacements in the event of failures at the Wood Pole substations.

Approximately 52 per cent of the 50 Wood Pole substations are over 50-years old, with 10 per cent over 60-years old. Approximately 45 per cent of equipment within the Wood Pole substations has been assessed as Poor or Very Poor, indicating that there is an increased likelihood of failure.

Summarize Solution:

Wood Pole substation investments are prioritized considering factors such as the age and condition of the wood poles, the condition of equipment within the substation, as well as the criticality of the substation. To address the above issues and risks, the following staging of investments is recommended:

- Firstly, a number of capital projects have been identified to remediate the risks associated with the Wood Pole substations. The scope of these will be tailored to suit the specific Wood Pole substation, and the risks, ranging from the component by replacement of targeted assets, to a more complete redevelopment of the substation;
- Secondly, a contingency strategy, utilizing mobile transformers, will continue to be implemented, as

necessary, to ensure mobile transformers are available to minimize the impacts of equipment failure; and

- Finally, consideration has been given to find opportunities to decommission stations where replacement can be avoided by finding other economical solutions.

Short- and Medium-Term:

Condition of assets are reviewed on a regular basis considering such factors as recurring test results, visual inspections, and, where required, detailed engineering assessments. This information is used to assess the risk of failure at each Wood Pole substation to help prepare consolidated list across the fleet and identify the potential timing to address the risks. Below is a list of those substations with a higher priority:

- Britannia;
- Monte Lake;
- Parson;
- Clinton;
- Chase;
- Joseph Creek;
- Sandspit;
- Lumby #2;
- Diana Lake;
- Canal Flats;
- Skookumchuck;
- Woss Lake; and
- Anahim Lake.

Long-Term:

The investments outlined above will address the highest priority risks. However, considering that a number of the Wood Pole substations were constructed in the 1970s and 1980s, additional work is anticipated in the long-term. The strategy and prioritization will continually be monitored over time.

Name of Capital Strategy, Plan or Study:
Asset Management Strategy - Section 2.1.11: Transmission Wood Poles

Summarize Issue:

BC Hydro has approximately 75,000 wood pole structures on the Transmission system. This equates to approximately 110,000 individual wood poles, as some structures are built using multiple wood poles. The average life of a wood pole is approximately 50 years. With the Wood Pole Test & Treat Program (inspection and maintenance), BC Hydro aims to achieve a 70-year life for transmission wood poles. Currently, 47 per cent of transmission wood poles are in the mid-life age class of 30 to 50 years old.

BC Hydro has safely maintained transmission reliability and quality of service through investment in wood pole structure replacements to address critical end-of-life wood poles and crossarms across the province. Over the last five years, an average of 668 structures and 319 crossarm (framing) replacements were completed each year with the majority of replacements in the Lower Mainland area (wetter and prone to biologic decay) and the Southern Interior (dry and prone to damage caused by woodpeckers). This means that over 10 per cent of the asset class (almost 1,000 transmission structures) is getting refreshed with life extension investments each year. This is a sustainable and acceptable rate of replacement based on the population demographics.

The main issues and risks associated with transmission wood poles include:

- Condition – managing the ageing population of poles and overall asset condition that could lead to safety and reliability risks;
- Availability of materials – reduced availability of large size wood poles and timbers that meet performance specifications could limit BC Hydro’s ability to replace end-of-life structures and negatively impact the life expectations for new structures;
- Environmental performance – efficacy of wood preservatives and preservation techniques currently approved in Canada;
- Constructability – difficulty in securing outages for structure replacements and concerns with access to farms and other private property results in delayed replacements; and
- Climate change – increase in extreme events such as storms and forest fires leading to pole damage. Longer and wetter winter cycles accelerate biological decay and all these factors increase the rate of pole replacements.

Summarize Solution:

To continue addressing the known issues and risks, the following staging of investments is recommended:

Short-Term:

- Target inspections of about 10,000 structures with the annual Test & Treat Program as per published standards. This allows wood pole life extension;
- Target replacement of approximately 700 wood pole structures and 300 crossarms with the annual Wood Structure and Framing Replacement Program; and
- Circuit refurbishment of 2L13/2L14.

Medium- and Long-Term:

- Continue the annual Test & Treat Program;
- Continue testing and research on wood pole end-of-life assessment, life extension, work prioritization and alternate structure materials in collaboration with Powertech Labs and international organizations to ensure best value for asset replacements and longer lasting materials for lowest total ownership cost of structures;
- Continue the annual Wood Structure and Framing Replacement Program at current levels; this program addresses end-of-life structures, ensures safety, maintains service levels and if required improves reliability; and
- Continue to develop Circuit Refurbishment Programs. These projects target efficiency where there are relatively large volumes of pole replacements on a single transmission line.

Name of Capital Strategy, Plan or Study:
Distribution Planning Practice - Section 6.1 and 6.4.2: New Feeders & Voltage Conversion

Summarize Issue:

BC Hydro’s distribution system experiences load growth which requires the addition of new feeders and voltage conversion to more effectively serve load over time. In addition, the distribution system technical requirements and customer expectations for reliability evolve over time. The Distribution Planning Practices (**Planning Practices**) establish planning criteria that guide the need for new feeders and voltage conversion. The Planning Practices also support the implementation of distribution system expansion and improvement capital projects which address capacity constraints and anticipated load growth, and maintain and improve distribution system performance including addressing customer reliability, safety risks and regulatory and legal requirements. The Planning Practices document is reviewed and updated regularly to consider factors such as new industry practices, standards, and technologies, along with financial, regulatory, and environmental requirements.

New Feeders (Planning Practice section 6.1)

New feeders are required as new load develops, for example:

- Loads on feeders may grow to the point where the individual feeder capacity is exceeded and a new feeder is needed to serve the additional load;
- A new feeder may be required to ensure faster customer service restoration in case of feeder outages; and
- A large customer may require a dedicated feeder for backup purposes.

New feeder projects recently completed include new feeders in Vancouver, Burnaby, Coquitlam, Maple Ridge, North Vancouver, Richmond, Surrey, Chilliwack, and Colwood. The significant areas of planned new feeder projects include: Abbotsford, Delta, and Kamloops.

Voltage Conversion (Planning Practice section 6.4.2)

Conversion of the primary voltage to a higher level may be required to:

- Increase system capacity to supply distribution customer load growth;
- Increase system flexibility for restoration and operations aligned with substation and transmission plans including the ability to transfer loads between feeders or substations;
- Increase system efficiency by reducing electrical system losses and improving customer service voltages; and
- Reduce congestion in heavily populated corridors.

Voltage conversions recently completed include portions in Vancouver, Burnaby, Coquitlam, North Vancouver, Richmond, Surrey, and Esquimalt. The other areas of planned feeder voltage conversions include: Vancouver, Burnaby, North Vancouver, Richmond and Surrey.

Summarize Solution:

To address the above issues, the following investments have been initiated:

Short-Term:

- Feeder circuit voltage conversions associated with the following substations:
  - Horne Payne, Lougheed, Richmond, George Dickie, and Quesnel;
- New Feeder circuits associated with the following substations:
  - Murrin, West Kamloops, Campbell River, Fleetwood; and
- Feeder extensions associated with the following substations:
  - Douglas Street.

Name of Capital Strategy, Plan or Study: **Asset Management Strategy – Section 3.1.8: Street Lighting**
Summarize Issue: BC Hydro owns and maintains approximately 90,000 street lights mounted on BC Hydro or Joint Use (co-owned with TELUS) poles, and 4,200 leased private outdoor lighting units installed on customer or BC Hydro owned poles located on private property. Most BC Hydro street lights are high pressure sodium technology while most private outdoor lights are mercury vapour technology. BC Hydro provides street lighting service to various customers (mainly municipalities) to: • Support night-time safety for the general public; and • Contribute to reliability by reducing outages due to vehicular accidents. The main issues and risks associated with street lighting include: • Approximately 20 per cent of BC Hydro’s street lights may contain polychlorinated biphenyls (**PCBs**), which must be removed from the system by December 31, 2025 in accordance with Federal PCB Regulations; • Municipalities are increasingly interested in implementing various cost and energy-saving initiatives such as Light Emitting Diode (**LED**) technology lights and adaptive controls; and • Meeting the street lighting outage response target of 10 working days is challenging in certain smaller districts of the province due to lack of dedicated resources.
Summarize Solution: The objective of this strategy is to replace conventional street lighting with LEDs and consider new technology to provide customers with increased flexibility of use. A street light replacement program to convert existing high pressure sodium and mercury vapour technology street lights to LED technology is current being developed with a target to being implementation in mid-2020. **Short-Term:** Work is ongoing to qualify manufacturers of LED street lights and adaptive control systems. Business justification is in progress to recommend a preferred LED solution which may or may not include adaptive controls. Once justification is approved, a rate application will be made to include LED technology as part of existing street light and private outdoor light rates. The current target to begin implementation of the conversion program is mid-2020. **Medium- and Long-Term:** The timeframe for to complete implementation is currently estimated in the range of two to four years after commencement of implementation.

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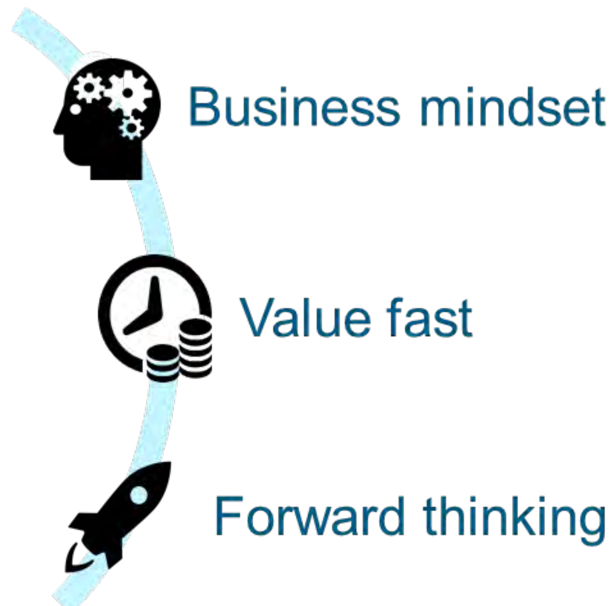
Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix L

BC Hydro Technology Strategy and 5-Year Plan

BC Hydro
Technology Strategy and 5-Year Plan

Supporting BC Hydro’s Service Plan Objectives



Prepared by the Technology Group

November 2018

BC Hydro
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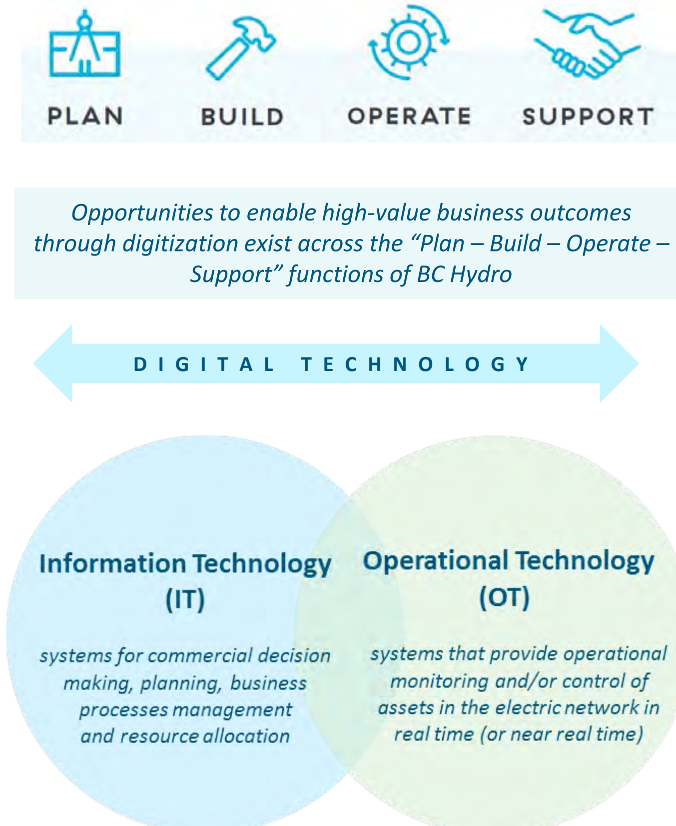
Introduction

Technology plays a critical role in the operation of BC Hydro and is embedded in virtually everything we do; from enterprise business systems, to the monitoring and controlling of field assets, to mobile devices in the hands of workers. Global trends, business competition, and high consumer expectations are driving rapid advances in technology. In the utility industry, the application of digital technology is viewed as essential in meeting future business objectives.

For BC Hydro, investment in technology can help us achieve our service plan objectives to provide reliable and responsive service, maintain affordable rates, continue to support clean, renewable energy and focus on safety above all else.

In this document, "technology" refers to digital technologies encompassing *information technology* (IT) as well as *operational technology* (OT). Traditionally separate domains in the electric utility business, the digital technology environments of IT and OT are now converging as the trend continues towards automation of all aspects of the power systems and the use of grid system data for business decision-making. New capabilities using rapidly evolving digital technologies such as cloud computing, mobility, internet of things, and machine learning, are being implemented as utilities modernize towards a more intelligent grid – this is the digitization of the utility industry.



Introduction

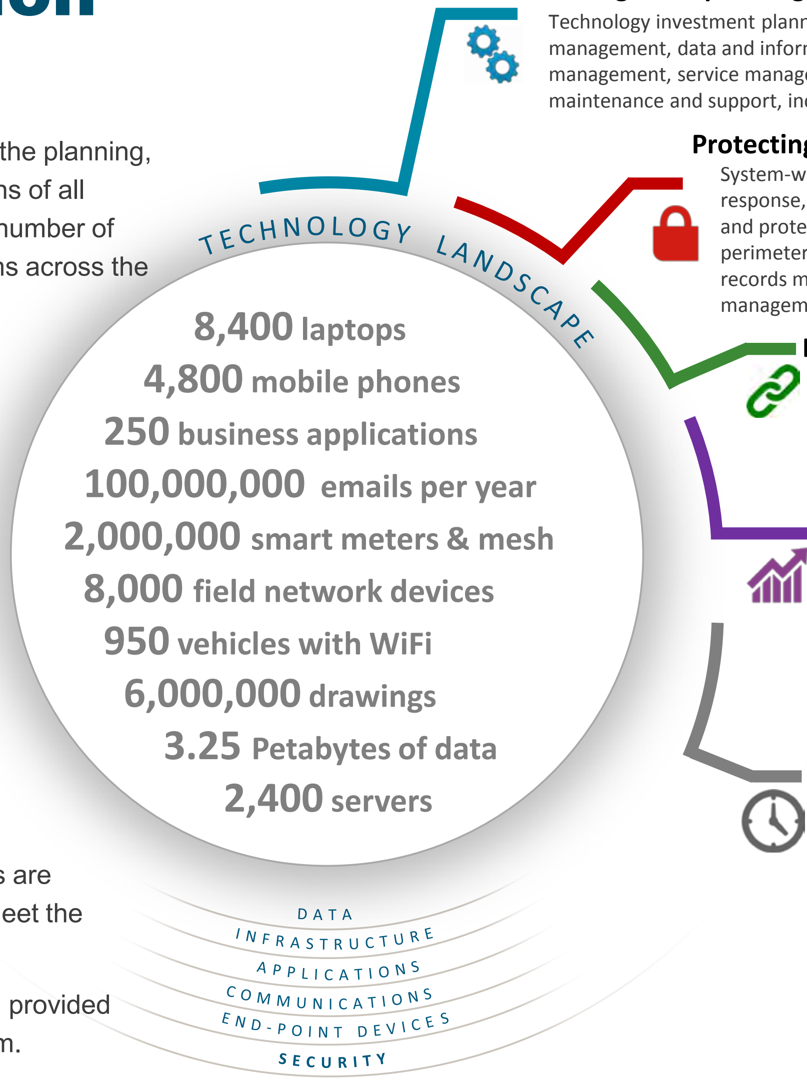
Our role

Technology is responsible for the planning, design, delivery, and operations of all information technology and a number of operational technology systems across the enterprise.

We provide technology leadership and oversight across BC Hydro. We actively collaborate with our organization to understand current and future needs. We are responsible for the enterprise technology architecture, and selection of appropriate technology solutions to deliver strong business outcomes.

Our work ensures our systems are reliable, secure, and able to meet the growing needs of BC Hydro.

Governance of our activities is provided by BC Hydro's Executive Team.



Planning and operating our complex environment

Technology investment planning, architecture and design, performance management, data and information governance, portfolio and resource management, service management, service desk, systems monitoring, maintenance and support, incident response and recovery

Protecting our systems and information

System-wide cybersecurity, system design, monitoring and response, testing, education, policy, compliance, detection and protection tools, vulnerability assessment, securing perimeters, privacy protection, security risk management, records management, information protection, drawings management, library and archive services

Ensuring the resilience of our systems

Service continuity planning and response, disaster recovery, risk management, high-availability architecture, cloud-based services, internal capabilities for critical functions, asset maintenance and health management

Enabling new business capabilities

Engaging with the business to understand their current and future needs, managing our capital investments and on-going sustainment, delivering high value projects on-time, on-scope and on-budget

Improving operational efficiency

Effectively managing vendors and contracts, retiring legacy assets, balancing internal and external resources, modernizing tools and processes, introducing agile methods, use of cloud, out-of-the-box solutions

3

BC Hydro
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Introduction

About this document

This Technology Strategy and 5-Year Plan is the result of extensive collaboration across BC Hydro. Its primary goal is to provide guidance and direction for future technology investments to meet compliance and security objectives, sustain and modernize our existing operations, and enable new business capabilities.

A clear strategy and plan is essential to inform the direction of future investments, but the approach looking forward must be flexible in order to adapt to, and exploit, the ever-changing technology landscape as well as to address new business opportunities as they arise. Given the rapid advancements in technology, and the continuing evolution of BC Hydro's business needs, the 5-Year Plan will be refreshed annually.

Our investment in technology is aligned with our capital plan over the next five years. The 5-Year plan describes the major investments we anticipate, however each will be supported by its own business case and initiated based on changing priorities, available funds and resources.

The purpose of this document is to:

- ✓ **Articulate BC Hydro's technology investment objectives**
- ✓ **Describe our strategy to meet these objectives**
- ✓ **Communicate the 5-Year Plan to guide investment and inform current and future regulatory submissions**

Context

- Our strategic objective
- Drivers for our strategy
- Digital value streams for electric utilities

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Technology Strategy

Our strategic objective

This Technology Strategy and 5-Year Plan is designed to support BC Hydro in achieving its Service Plan Objectives:

- ✓ **Set the standard for reliable and responsive service**
- ✓ **Ensure rates are among the most affordable in North America**
- ✓ **Continue British Columbia's leading commitment to renewable clean power**
- ✓ **Safety above all**

Implementation of technology solutions has the potential to advance each of these objectives, for example:

- By maintaining the health, stability and security of our digital systems we assist in ensuring the reliability and responsiveness of our service.
- Providing tools to streamline workflows, optimize work and asset management, and inform decision making all enable productivity improvements that lead to affordable rates.
- Mobile applications can provide location and job specific information to assist with improving safety outcomes for field workers.

Technology Strategy

Drivers for our strategy

BC Hydro is affected by numerous drivers having a direct impact on the strategy we employ to meet our objective. These drivers affect the type of investments we make, how we prioritize investments and adapt to future trends.

BC HYDRO SERVICE PLAN OBJECTIVES

- Safety above all
- Set the standard for reliable and responsive service
- Ensure rates are among the most affordable in North America
- Continue British Columbia's leading commitment to renewable clean power

GOVERNMENT DIRECTION, REGULATION, AND COMPLIANCE

- BCUC regulation and rates forecast
- Mandatory Reliability Standards (MRS) and NERC CIP (Critical Infrastructure Protection) regulations requirements are increasing

BC HYDRO BUSINESS UNIT OUTCOMES

- Integrated Planning – optimize investments
- Capital Infrastructure Project Delivery – reduce delivery, safety and environment risk
- Operations – improve productivity
- Safety – improve safety outcomes, reduce risk
- Business Support Services – improve productivity and service

UTILITY INDUSTRY DIRECTION

- Increased expectations for digital solutions to improve safety, productivity, and management visibility
- Increasing OT/IT convergence provides opportunities for knowledge and resource sharing
- Security and compliance continues to be a rapidly increasing and growing market, ever changing and demanding
- A growing need to control distributed and customer side sources of energy as well as demand side management and load control
- Increasing electrification of transportation and management of charging infrastructure
- Climate change adaptation and mitigation

Technology Strategy

TECHNOLOGY ASSET HEALTH

- Existing systems are on ageing platforms that cannot be supported or are incompatible with newer operating systems
- Built in product obsolescence leads to regular upgrades to retain product support

TECHNOLOGY MARKET DIRECTION

- Subscription licensing is a major trend within the software industry changing our cost profile away from capital investment and towards operating costs
- Commoditization of technology services can result in lower costs, for example data network transport costs
- Everything as a service or cloud services are becoming the norm, changing our cost profile away from capital investment and towards increased operating costs

TECHNOLOGY TRENDS

- Cloud services are growing rapidly offering scalability, disaster recovery, and mobility enablement
- Mobility offers productivity benefits for field workers
- Internet of things, Edge computing and Digital twin offers opportunities in asset monitoring and performance management
- Artificial intelligence and robotic process automation offer efficiency gains through replacement of manual processes
- Augmented and virtual reality for training, virtual mentoring and maintenance support
- Robotics and drones for inspections and progress reporting
- Blockchain for secure transaction processing

Technology strategy

Digital value streams for electric utilities

Digital technologies are used to enable new and improved capabilities and drive value across all functions of the utility.

PLANNING & DESIGN

High performance computing, cloud solutions, and advanced analytic and drafting tools enable more comprehensive and timely energy and system planning, load forecasting, resource management, engineering and design.

ASSET MANAGEMENT

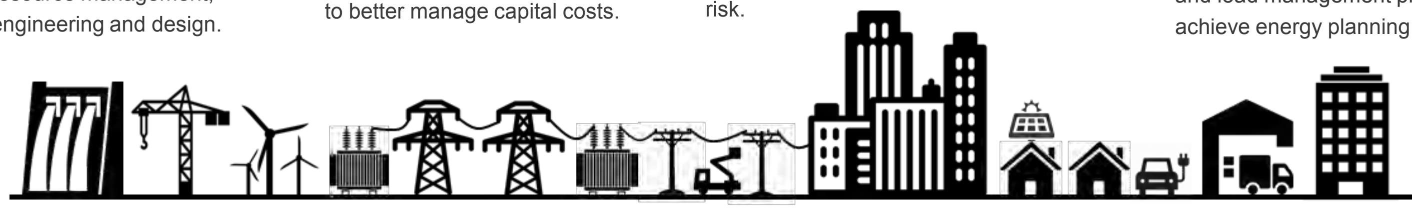
Real-time asset health information enables condition-based maintenance and just-in-time replacement to reduce asset sustainment costs. Asset health also provides for optimized investment planning to better manage capital costs.

MOBILE WORKFORCE

A fully mobile workforce seamlessly completes their field work. Job information is available, inspections are captured, drawings updated, and problems and progress automatically reported. Safety training and support is available on demand. Value is achieved through productivity, efficiency and reduced safety risk.

CUSTOMER ENGAGEMENT

Multi-channel technologies and relationship management tools improve quality and timeliness of customer interactions. Self-service reduces our costs and improves customer experience. Systems to support demand side management and load management programs help achieve energy planning targets.



WORK MANAGEMENT

Productivity, efficiency and risk reduction can be achieved through mobile applications, digital workflows to manage information and record keeping, use of drones to capture progress images, access to real-time data and business intelligence and analytics. Scheduling tools and optimization algorithms make managing work, during both normal and emergency situations, more efficient.

GRID INTELLIGENCE & CONTROL

Smart devices on the grid help optimize power delivery and resilience, and give operators and field service crews visibility into outages, faults, power quality issues, and the status of energized equipment. Digital systems manage distributed energy resources, automate connect and disconnect functions, power distribution and power quality.

SAFETY & SECURITY

Sensors, imaging and internet of things technologies provide visibility to facilities that are remote and/or unmanned. Monitoring and surveillance technologies improve identification and response to safety and security situations. Mobile field tools aid in worker and crew safety. Improved protection of digital information, systems and equipment reduces cyber security risk.

BUSINESS OPERATIONS

All business functions benefit from improvements to work processes, access to analytics, decision making, information management, and knowledge retention tools. Opportunities also exist to improve hiring, development and retention of valuable employees through specialized tools.

BC Hydro
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Approach

- Principles
- Critical success factors

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Technology Strategy

Principles

We will adopt a business mindset, ensuring we work within our constraints to achieve the best outcomes for BC Hydro while maintaining the security and integrity of our information and systems at all times. We will adapt our solutions and processes to exploit short term opportunities and deliver outcomes early and often. We will develop technology roadmaps to ensure alignment on business solutions, leverage new technologies and prepare for technology obsolescence.

Business mindset

Optimize our investment

- ✓ Use a prioritization and selection methodology to achieve optimal outcomes
- ✓ Develop a plan that works within the constraints of costs and resources
- ✓ Use structured decision making in choosing investment alternatives
- ✓ Leverage existing systems
- ✓ Use a risk based approach to sustainment

Value fast

Deliver outcomes early and often

- ✓ Adapt delivery processes to deliver early and often
- ✓ Use a flexible architecture to support early value
- ✓ Leverage our existing systems
- ✓ Use off-the-shelf products
- ✓ Use cloud services

Forward thinking

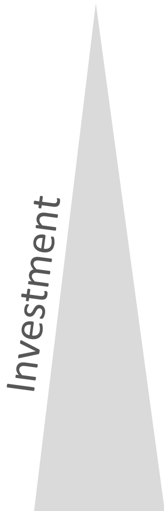
Leverage technology

- ✓ Develop roadmaps for foundation technologies
- ✓ Ensure alignment of short-term business solutions
- ✓ Plan for future obsolescence

Technology Strategy

Principles – Business mindset

- **Justify and prioritize investments.** Investment proposals are selected into the portfolio based on relative value to the organization. Compliance, security, sustainment and risk mitigation solutions receive higher priority followed by those required to enhance business capability. Business cases must identify value and articulate specific benefits. Value (both cashable and non-cashable) from the investment must support the total cost of the investment.



Initiative / Investment	Description
Enhance our Capability	Discretionary activities that provide new or improved business capabilities
Manage our Risk and Sustain Productivity	Critical activities needed to ensure reliable and safe operations and to maintain the current level of productivity for our users
Compliance & Security	Mandatory activities needed to meet government/BCUC/NERC/WECC requirements

- **Work within our constraints.** Investment decisions are subject to the application of constraints due to funding, resource capacity, available skill sets, and ability of the organization to sustain and absorb change. Choices between investment options are decided through structured decision making.
- **Track the outcomes of investments**. Sponsors of technology-enabled initiatives are required to track benefits throughout implementation and into sustainment.

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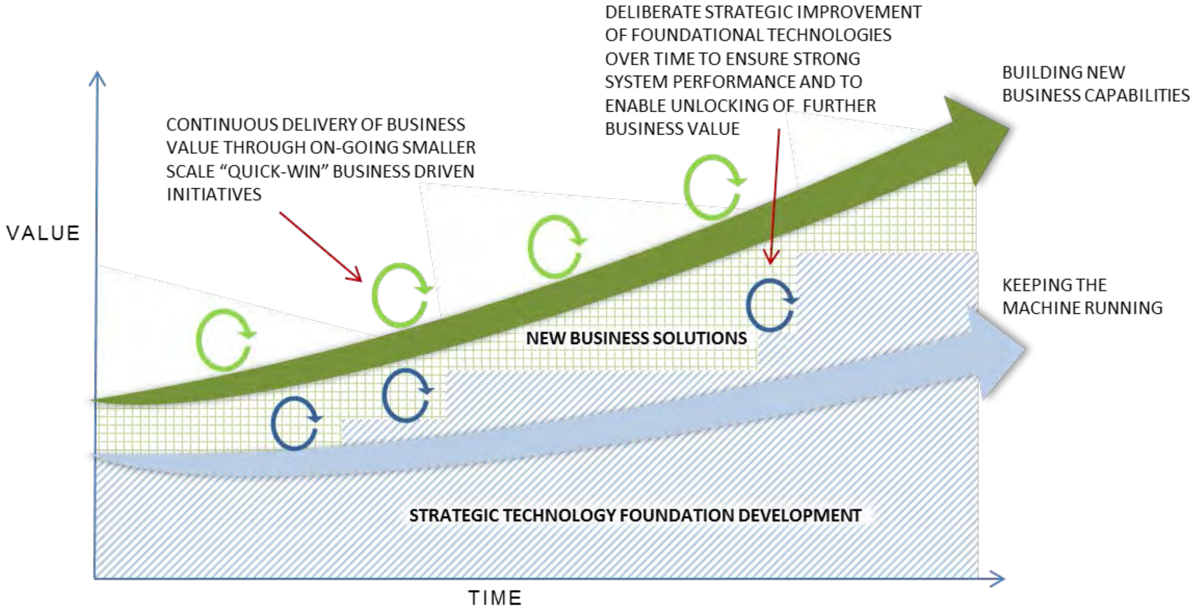
Technology Strategy

Principles – Value fast

- **Deliver value early and often.** Our approach is to exploit opportunities to deliver value early from interim solutions, even at a cost – provided the value exceeds the cost over the life of the interim solution. We will use "two-speed" or "agile" delivery methods, where appropriate, to expedite implementation of solutions.
- **Ensure architectural flexibility.** We will make investments that advance our delivery of value while still maintaining flexibility in our systems architecture. This allows for incremental and early value delivery, while implementing efficient and sustainable long-term foundation investments.



The diagram shows how we strive to deliver value early and often through incremental improvements (in green) while continuing to invest in our technology foundation for long term strategic business enablement (in blue)

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Technology Strategy

Principles – Forward thinking

- **Build for the future.** Technology roadmaps describe how we can invest in our foundation and leverage new technologies to enable our strategic objective. The roadmaps sequence initiatives, identify decision points, and provide unconstrained scheduling of milestones to enable business outcomes. Given the dynamic nature of technology and technology industry changes as well as changes to BC Hydro's environment, our roadmaps will be updated annually. The following summaries describe current guidance for each foundation area however all initiative proposals require individual investment justification.

NETWORK CONNECTIVITY	Sustain existing wide area, field area and local area networks, as well as extend network bandwidth and coverage to our more remote sites. Continue to refresh our network equipment based on end-of-life cadence, meet current and future capacity requirements, and take advantage of software alternatives as they become available. Continue to invest in wireless networks for our facilities and vehicles to enable workforce mobility, asset management, and increased safety and security.
ENTERPRISE APPLICATIONS	Continue to upgrade our enterprise applications based on a cadence to maintain product support. As upgrades are scheduled, take advantage of opportunities to modernize current platforms as per industry direction to remain current and reduce risk of obsolescence. Implement new customer contact centre systems to replace those that are not meeting requirements of availability and reliability, as well as modernizing the stack to extend and enhance current functionality for our customers. For Enterprise Resource Planning (ERP), we have adopted a "Core ERP" approach in which SAP is our single system of record for enterprise data but the systems our users engage with may be "bolt-ons" or cloud service products. Our technology roadmap includes the implementation of supply chain and the potential future adoption (subject to our structured decision making framework) of Enterprise Asset Management and Work Management in SAP, allowing for the decommissioning of Passport. Future migration of SAP to the HANA© platform for in-memory processing, offers improved performance and easier data access.
CLOUD & DATA CENTRE	BC Hydro's approach to cloud is to adopt services on a case-by-case basis. Use cloud services as needed for compute power, specific business functionality, disaster response environment, collaboration and productivity. Continue to refresh our data centre servers, storage and other equipment based on end-of-life cadence. As equipment is replaced, leverage opportunities to consolidate racks as well as review cloud options. Leverage major product upgrades in line with the direction of our product vendors as they move to cloud platforms.

Technology Strategy

Principles – Forward thinking

MOBILITY SERVICES

Extend and improve our mobile services and mobile workforce capabilities. Continue to refresh our user's mobile phones and devices based on recommended refresh cadence, break/fix and device management requirements. Replace our existing mobile application management platform to better support device management, performance and required functionality. To facilitate future development of field worker applications, implement a suite of container services, application program interfaces (APIs) and a mobile work management platform. Strive to extend our device management capability to a broader range of devices.

GIS

Our approach is to use the ESRI platform for applications requiring GIS (Geographic Information System) and defer decisions on our Smallworld GIS applications until a major product replacement or upgrade. Focus on integrating GIS with our CAD (Computer Aided Design) tools, mobile application and ERP capabilities in order to support designers, field workers, asset management and work management. Extend our use of GIS in application development to provide geographic location search to access information, provide operational and emergency situational awareness. Continue to upgrade our GIS platforms based on a cadence to maintain product support.

PERSONAL WORKSPACE

Continue to refresh personal computing devices based on recommended refresh cadence, productivity, break/fix and device management. Upgrade our desktop environment to Windows 10 to improve performance and functionality, implement Microsoft's Office 365 suite of tools to support improved collaboration and productivity, and migrate to Microsoft Exchange Online to optimize storage capacity, ensure product support and align with product vendor direction. Upgrade our information collaboration (Sharepoint) platform and make Sharepoint online available for collaboration in the future. We expect to maintain an "on premise" presence for security and business continuity.

Technology Strategy

Principles – Forward thinking

CYBER SECURITY

BC Hydro uses a risk-based approach to cyber security and information protection. New investments are made based on compliance requirements, emerging threats and retaining our risk posture. Comply with NERC (North American Electric Reliability Corporation) CIP (Critical Infrastructure Protection) versions 5, 6 and 7. Sustain and maintain our information management systems, corporate monitoring tools, firewalls and other protection equipment based on end-of-life cadence, and risk mitigation. Leverage upgrades to modernize our architecture and optimize network segmentation through software as it becomes operationally mature. To improve our overall risk posture, apply information technology (IT) cybersecurity best practices to our operational technology (OT) environments and develop an information protection program to improve security of our systems of record, information sharing and records management platforms.

BUSINESS INTELLIGENCE & ANALYTICS

BC Hydro's direction is to adopt a self-service model for analytics in which users are given access to data and can use their own tools and analysts to meet their needs. In support of this approach, work to broaden access to our smart meter data, implement our SAP Business Warehouse (BW) on HANA© for improved performance and easier data access, and implement a virtual data warehouse to improve ability to share both enterprise and business specific data across business functional areas. In addition, implement a telematics solution for fleet data analytics, fleet asset management and fleet operations, as well as a platform for asset performance management to enable business outcomes such as enhanced condition based maintenance. Continue to leverage the Province of BC and TELUS Strategic Innovation Fund to explore implementation of an enterprise data collection platform (internet-of-things) to support business outcomes related to worker and public safety.

ENERGY MANAGEMENT

BC Hydro's grid modernization work identified opportunities for improving operations, security, safety and visibility to the grid with many of these improvements involving the deployment of digital technologies. Our approach is to take advantage of these opportunities on a case-by-case basis depending on their ability to meet our strategic objectives, the priorities of our organization, the maturity of the technologies and business constraints. Continue to upgrade our Energy Management System and Outage Management System (PowerOn) to maintain product support, and work to extend the use of our smart meter data to support outage management objectives. In the future, we expect to deploy an integrated grid management system including bulk energy system, advanced distribution management (including outage management and switching order management), distributed energy resource management and demand response management to improve performance, meet business outcomes and align with product vendor direction.

Technology Strategy

Critical success factors

Delivery of the strategy demands that we address some non-technical factors that will be critical to success:

1. **Early engagement with our business leaders on strategic direction.** Technology must be recognized as necessary to achieving the goals of the organization. Technology leaders must be invited to work closely with business leaders during their planning to understand the strategic objectives and advise on opportunities for technology enablement.

2. **Streamline our delivery processes to be fit for purpose.** We have a robust IT delivery process (ITDSP) which has served us well in providing strong guidance and oversight of our project delivery function. This process does not scale adequately for our lower risk project activity nor provide the agility needed for user facing capability development. We are developing alternative delivery models (both variants to ITDSP as well as 2-speed or agile models) to meet the needs of modern technology deployment.

3. **Resource availability and reduction in capacity bottlenecks.** Project initiation decisions must consider not only capital investment availability. Equal emphasis is required for the availability of operating funds to support the non-capital project costs and on-going sustainment costs, and availability of resources to deliver and support pre-project and project delivery activities.

4. **Portfolio management prioritization and selection processes.** Capital investment prioritization and selection must be based on a common value framework for the organization and an integrated selection process that allows for trade-offs in non-sustainment investments. Investment decisions are subject to the application of constraints due to funding, resource capacity, available skill sets, sustainment capabilities, and ability of the organization to absorb change.

5. **Funding**. The current funding model based on capital investment for technology does not support future subscription and cloud services investments that typically require operating funds. A new funding model is required to ensure the success of future technology investment and operations.

6. **Governance, risk and compliance.** Continued central governance of systems architecture and project delivery is required to optimize resources and ensure compliance with security, privacy, delivery and architecture standards and policies.

5-Year Plan

- Developing the plan
- Future business outcomes
- Prioritization and constraints
- Investment summary
- Measuring our success
- Conclusion

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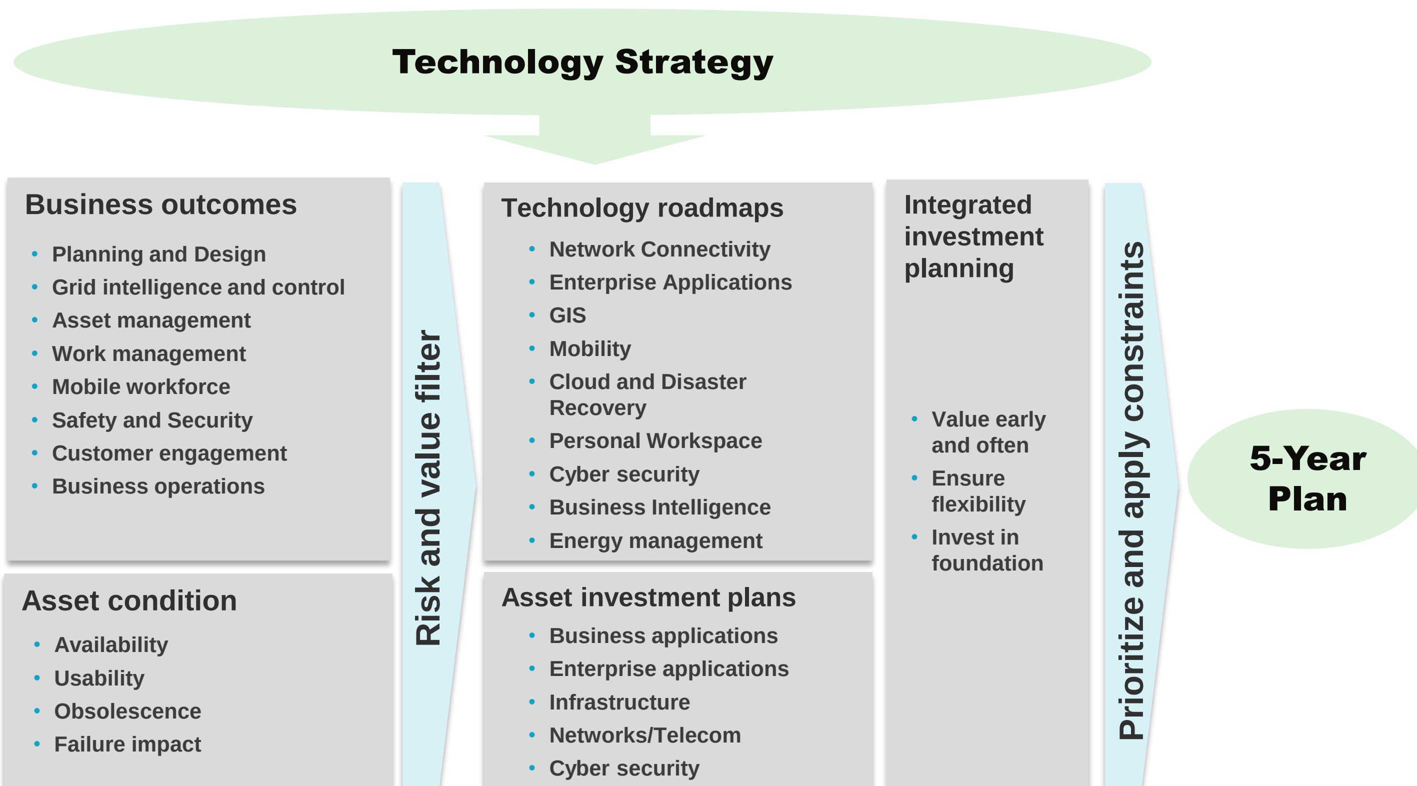
5-Year Plan

Developing the plan

Fundamentally, the objective of the Technology group is to enable business outcomes and sustain the availability and security of our existing assets.



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5-Year Plan

Developing the plan

Over a period of six months, the Technology group facilitated over twenty workshops with business group leaders to identify desired business outcomes for the next five to ten years. Over two hundred outcomes were articulated, with approximately half of those dependent on a technical solution. These outcomes were assessed for value based on executive and senior management's best judgement on their contribution to meeting our strategic objectives. This information is used to inform our technology roadmap development.

The condition, health and longevity of our assets are assessed annually by our Technology team. Our Business Partner Services team also use their best judgement in how well the business and enterprise applications are meeting the needs of BC Hydro. This information, together with the impact of lost availability, is used to inform our technology asset investment plans.

Integrated investment planning activities bring together the technology roadmap view, the asset investment view, and alignment with business expectations. The result is our aspiration for technology investment. Application of selection and prioritization criteria, as well as funding and resource constraints, leads to the development of the five year plan.

This 5-Year Plan shows the investments currently anticipated based on BC Hydro's capital plan for the next five years. Our technology capital plan is constrained beyond 2020 and this is expected to limit investments to improve business capabilities. In the event that additional resources become available, we will focus on investments that provide opportunities for operational efficiencies.

5-Year Plan

Future business outcomes

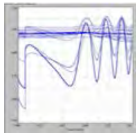
Our Technology team reviewed and aggregated the business outcomes for commonalities and determined the underlying technology investment needed. This is a summary of the aggregated business outcomes.

VALUE STREAMS

BUSINESS OUTCOMES

PLANNING & DESIGN

- Enhanced load forecasting and energy planning
- Enhanced engineering design



GRID INTELLIGENCE & CONTROL

- Distribution grid management
- Demand response management
- Digital substations
- Distributed energy resource management
- Resilient tele-communications networks

ASSET MANAGEMENT

- Integrated and optimized investment planning
- Asset performance management
- Asset intelligence for decision making
- End-to-end asset management

WORK MANAGEMENT

- Operations work planning and scheduling
- Optimized planned outage management
- Real-time monitoring and management of work

MOBILE WORKFORCE

- Ability to complete job on site
- Safety practices integrated into work process on site
- Work site awareness
- Real-time visibility to grid status on site
- Ability to collect quality information from the field

SAFETY AND SECURITY

- Resilient and secure IT and OT systems
- Real-time situation awareness during emergencies
- Physical grid security
- Automated facility security
- Enhanced dam safety systems

CUSTOMER ENGAGEMENT

- Customer inclusion in conservation and electrification programs
- Improved outage and restoration information
- Customer work booking
- Optimized customer service interactions

BUSINESS OPERATIONS

- Optimized supply chain function
- Optimized back office processes
- Enhanced data access and business intelligence
- Improved information, records management, search
- Improved employee experience, productivity and collaboration
- Workforce planning and development

5-Year Plan

Prioritization and Constraints

There are many opportunities for utilizing technology to unlock value in BC Hydro but it is not possible to achieve all outcomes all at once. Therefore, it is necessary to **prioritize** the outcomes and focus on those which we consider most important to the organization. In general, mandatory initiatives needed to address *compliance and security* are the highest priority and critical initiatives that address *risk management and sustainment of productivity* are next.

Initiative / Investment	Description
Enhance our Capability	Discretionary activities that provide new or improved business capabilities
Manage our Risk and Sustain Productivity	Critical activities needed to ensure reliable and safe operations and to maintain the current level of productivity for our users
Compliance & Security	Mandatory activities needed to meet government/BCUC/NERC/WECC requirements

Initiatives that *enhance our capability* are considered discretionary and are third in priority ranking. It should be noted, however, that these initiatives may provide significant benefits and help us in achieving our strategic objectives.

Once prioritized, it is necessary to apply our **constraints** in order to develop a plan that can be delivered with confidence. We apply a number of critical constraints including,

- The Technology team capacity
- Capital and operating funding
- Business capacity for change
- Availability of BC Hydro and contractor support resources
- Technical dependencies
- Technology maturity

5-Year Plan

Investment summary

Under the current constraints, work will continue to complete projects underway however only a limited number of new business value initiatives will be undertaken. The bolded outcomes are those that are wholly or partially addressed by major planned initiatives.

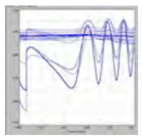
VALUE STREAMS

BUSINESS OUTCOMES

PLANNING & DESIGN

- Enhanced load forecasting and energy planning
- Enhanced engineering design

GRID INTELLIGENCE & CONTROL



- Distribution grid management
- Demand response management
- Digital substations
- Distributed energy resource management
- Resilient tele-communications networks

ASSET MANAGEMENT

- **Integrated and optimized investment planning**
- Asset performance management
- Asset intelligence for decision making
- End-to-end asset management

WORK MANAGEMENT

- **Operations work planning and scheduling**
- **Optimized planned outage management**
- Real-time monitoring and management of work

MOBILE WORKFORCE

- Ability to complete job on site
- **Safety practices integrated into work process on site**
- Work site awareness
- Real-time visibility to grid status on site
- Ability to collect quality information from the field

SAFETY AND SECURITY

- **Resilient and secure IT and OT systems**
- Real-time situation awareness during emergencies
- **Physical grid security**
- Automated facility security
- **Enhanced dam safety systems**

CUSTOMER ENGAGEMENT

- Customer inclusion in conservation and electrification programs
- Improved outage and restoration information
- Customer work booking
- Optimized customer service interactions

BUSINESS OPERATIONS

- **Optimized supply chain function**
- Optimized back office processes
- Enhanced data access and business intelligence
- Improved information, records management, search
- Improved employee experience, productivity and collaboration
- Workforce planning and development

5-Year Plan

Investment summary

With the application of prioritization and constraints, our investments over the next five years will be driven primarily by compliance, security and sustainment. There will be some investment in managing our safety, operations and business risk with limited opportunities to improve business capabilities. Major initiatives are listed here under the appropriate outcome.

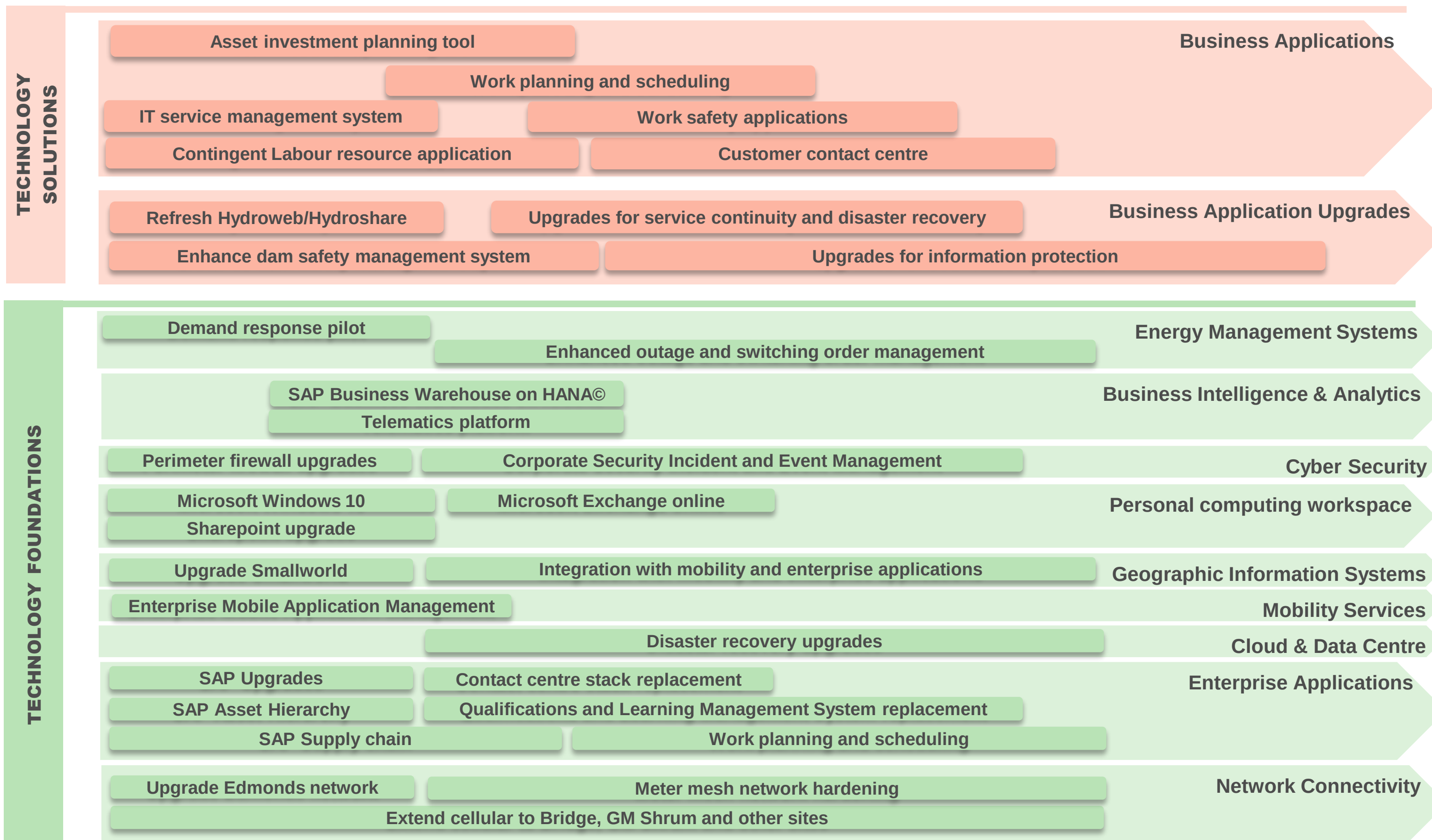
Investment category	Outcome description
Enhance our Capability	**Integrated and optimized investment planning** • Asset investment is integrated and optimized based on enterprise priorities • Information is available for vehicle asset optimization and performance management **Operations planning and work scheduling** • Work is scheduled centrally based on priority, available skillsets and location of resources (partial) **Optimized planned outage management** • Integrate planned outage management across Generation Supply Operations and Grid Operations **Optimized supply chain function** • Optimized process for procuring contingent labour resources • Optimized supply chain processes
Manage our Risk and Sustain Productivity	**Resilient OT and IT systems** • Sustain systems to ensure product support and systems availability • Improve service continuity and disaster recovery capability **Safety practices integrated into work processes on site** • Access to safety information and worker (including contractor) qualifications confirmed on site **Enhanced dam safety systems** • Dam safety engineers have easy access to dam safety information • Sensor and telecommunications networks are extended to increase dam safety visibility
Compliance & Security	**Physical grid security** • Ensure compliance with NERC CIP regulation **Secure OT and IT systems** • Maintain our cyber security risk posture

5-Year Plan

Investment summary

The diagram below shows the sequence of technology investments required to support planned initiatives.

Time



5-Year Plan

Measuring our success

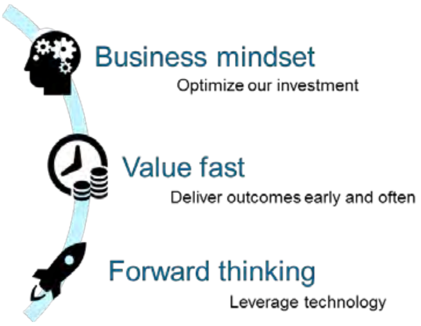
The Technology group has a variety of ways to track and measure the success of our capital investments. These range from the immediate and quantifiable, such as operational and delivery metrics, to the completely qualitative business satisfaction survey. We recently introduced a benefits tracking process for business capability driven initiatives. In this process both quantitative and qualitative assessments are made over a period of time following deployment of a solution.

- **Operational Metrics** – Technology uses a number of metrics to evaluate and track the performance of our systems, services, and vendors.
- **Delivery Metrics** – Technology uses a number of metrics to assess and track the performance of our delivery which include measures on cost, schedule, and quality.
- **Business satisfaction** – Technology conducts an annual satisfaction survey to solicit feedback from across the business of the level of satisfaction with Technology delivery and services.
- **Project Benefits** – Benefits from initiatives undertaken as part of implementing technology solutions will be tracked to assess how well they deliver on the expectations set out in their respective business cases.

Technology Strategy and 5-Year Plan

Conclusion

Our strategy describes BC Hydro's landscape and the drivers that influence our future business and technology decisions; our overall objective is to help BC Hydro achieve its service plan goals through the use of technology. We identify eight value streams across BC Hydro through which technology can unlock significant benefits. Our approach is to operate with a *business mindset*, to deliver *value fast*, and to be *forward thinking* in all we do.



BC Hydro's 5-Year Technology Investment Plan identifies expected business outcomes from across planning, delivery, operations and business support functions. The outcomes are assessed based on their ability to help achieve our service plan objectives. Following prioritization and the application of constraints, the Plan describes the outcomes we expect to achieve in the next five years and the corresponding investments in technology.

We must also sustain and maintain our existing systems. Investments for sustainment include refreshes for infrastructure, personal devices, network, telephony and cyber security assets, as well as upgrades and replacement of business and enterprise applications.

The plan reflects corporate planning activities and uses input from BC Hydro's executive and senior managers as well as the Technology subject matter experts. BC Hydro uses an annual planning cycle to maintain currency of plans and adapt to changes. We expect to update this plan annually.

BC Hydro
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Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix M

Asset Health - Generation

Table of Contents

1 Introduction

Equipment health is assessed for Generation, Transmission and Distribution assets. The information is used for the life-cycle management of assets, including supporting the need for capital investments. The methodologies used provide a systematic, objective, repeatable, and transparent assessment of asset health.

In December 2018, the Office of the Auditor General of B.C. released an independent audit of Capital Asset Management in BC Hydro. This audit is included as Appendix F. With regards to BC Hydro's asset health information, the audit stated:

> "Asset information is current and reliable
>
> BC Hydro has collected the information it needs to support good asset management practices. BC Hydro knows the service requirements that its electricity-generating, transmission and distribution capability must meet. This knowledge is informed by information about its assets that is current, comprehensive and routinely updated. Within its asset knowledge base, BC Hydro keeps records of asset condition and monitors asset performance, information that in turn informs decision-making and planning functions.
>
> BC Hydro uses an equipment health rating methodology, which captures in a standardized way the actual performance of equipment, relative to design specifications and operational expectations, as well as maintenance activity and service life estimates. BC Hydro has been working to ensure that these records are all up to date and has put in place monthly inter-unit meetings to discuss emerging equipment issues or unanticipated events that could affect asset performance and trigger needed action."

Summaries of the methodologies and Generation asset health information are provided below.

2 Generation Equipment Health Ratings

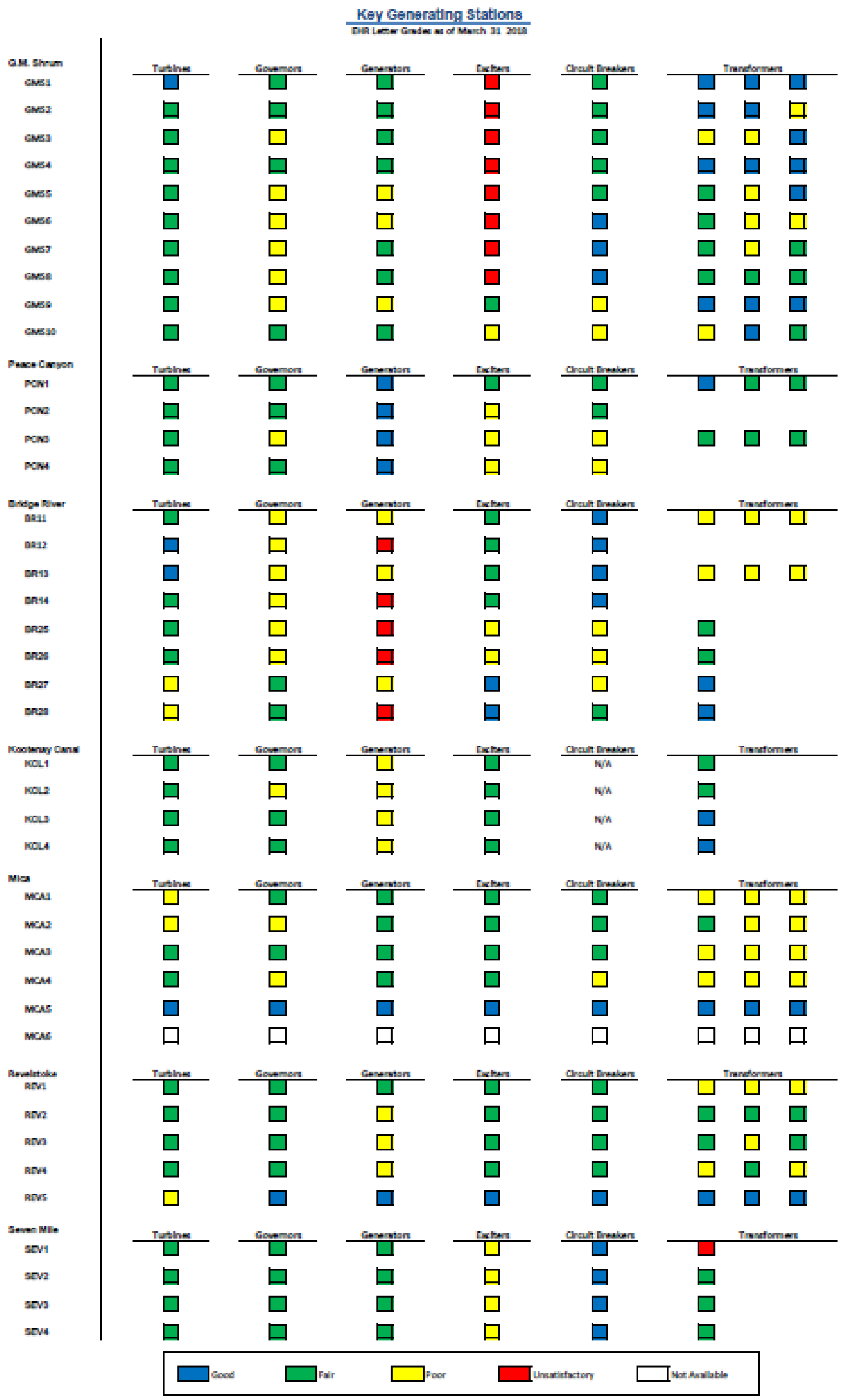
Generation periodically evaluates the condition of its major assets (turbines, generators, governors, exciters, transformers, and circuit breakers) based on the latest available maintenance test and inspection data. Health assessments are based primarily on asset condition but also consider safety and environmental issues, reliability, design deficiencies, asset age and industry expected life and availability of spare parts and technical expertise.

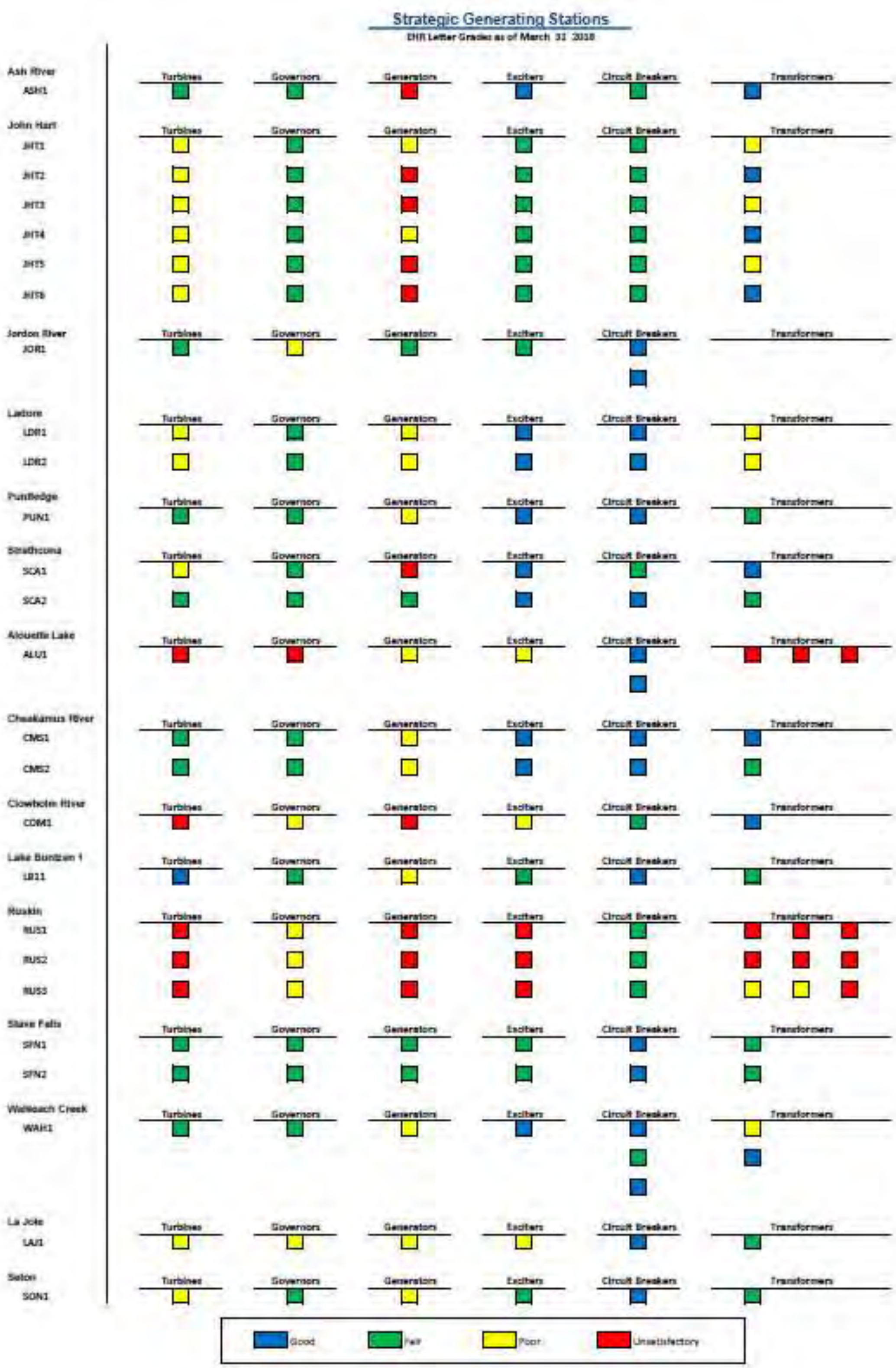
Each health assessment results in a rating of Good, Fair, Poor, or Unsatisfactory:

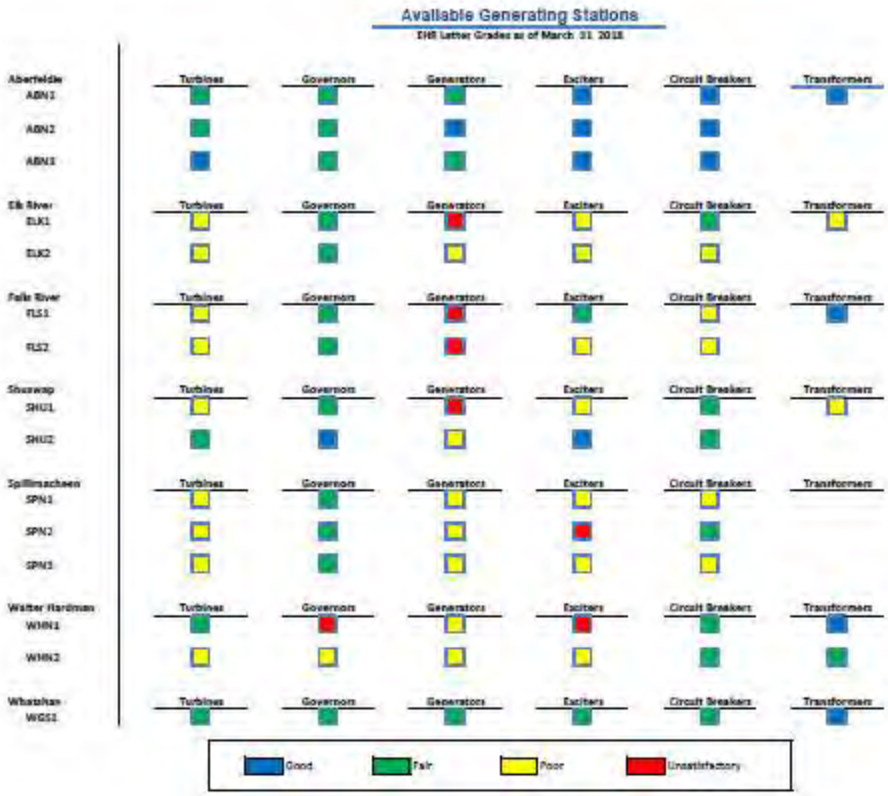
- **Good:** The asset is in as new condition, with no noticeable deterioration or defects;
- **Fair:** There is some normal deterioration of the asset with one or more minor defects; function is not affected;
- **Poor:** There is serious deterioration of the asset or serious defects in at least some portions of the asset; function is affected; and
- **Unsatisfactory:** There is extensive deterioration of the asset and the asset no longer functions as designed.

Assets that have an Equipment Health Rating of Poor or Unsatisfactory are considered to have an increased likelihood of failure. Assets assessed as being in unsatisfactory condition are believed to have the highest likelihood of failure, with capital investment or replacement generally recommended within the next five to seven years. Investments in assets assessed as poor are generally considered with the next 10 to 12 years.

Equipment Health Ratings for Generation assets as of April 2018 are provided below.


Key Generating Stations
G.M. Shrum
Peace Canyon
Bridge River
Kootenay Canal
Mica
Revelstoke
Seven Mile
Turbines
Governors
Generators
Exciters
Circuit Breakers
Transformers
N/A
Good
Fair
Poor
Unsatisfactory
Not Available


Strategic Generating Stations
Ash River
ASH1
John Hart
JHT1
JHT2
JHT3
JHT4
JHT5
JHT6
Jordon River
JOR1
Ladore
LDR1
LDR2
Puntledge
PUN1
Strathcona
SCA1
SCA2
Alouette Lake
ALU1
Cheakamus River
CMS1
CMS2
Clowholm River
COM1
Lake Buntzen 1
LB11
Ruskin
RUS1
RUS2
RUS3
Stave Falls
SFN1
SFN2
Wahleach Creek
WAH1
La Joie
LAJ1
Seton
SON1
Turbines
Governors
Generators
Exciters
Circuit Breakers
Transformers
Good
Fair
Poor
Unsatisfactory


Available Generating Stations
Turbines
Governors
Generators
Exciters
Circuit Breakers
Transformers
Aberfeldie
ABN1
ABN2
ABN3
Elk River
ELK1
ELK2
Falls River
FLS1
FLS2
Shuswap
SHU1
SHU2
Spillimacheen
SPN1
SPN2
SPN3
Walter Hardman
WHN1
WHN2
Whatshan
WGS1
Good
Fair
Poor
Unsatisfactory

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix N

Asset Health – Transmission and Distribution

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List of Tables

1 Introduction

Asset Health is assessed on a regular basis for all BC Hydro assets. Transmission and Distribution Asset Management developed a methodology called Asset Health Index to evaluate the health of Transmission and Distribution assets. The information is used for the life-cycle management of assets, including supporting the need for capital investments. The methodology provides a systematic, objective, repeatable, and transparent assessment of asset health.

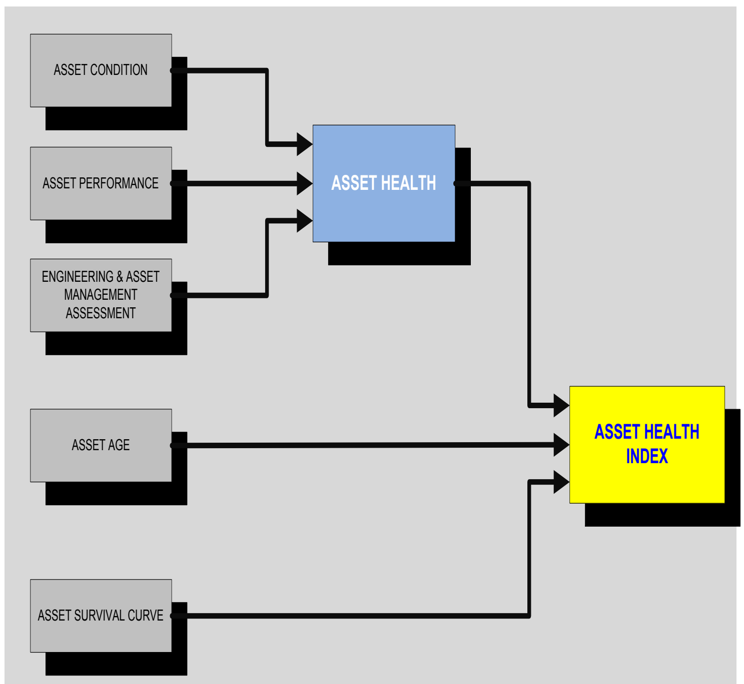
In December 2018, the Office of the Auditor General of B.C. released an independent audit of Capital Asset Management in BC Hydro. This audit is included as Appendix F. With regards to BC Hydro's asset health information, the audit stated:

> "Asset information is current and reliable
>
> BC Hydro has collected the information it needs to support good asset management practices. BC Hydro knows the service requirements that its electricity-generating, transmission and distribution capability must meet. This knowledge is informed by information about its assets that is current, comprehensive and routinely updated. Within its asset knowledge base, BC Hydro keeps records of asset condition and monitors asset performance, information that in turn informs decision-making and planning functions.
>
> BC Hydro uses an equipment health rating methodology, which captures in a standardized way the actual performance of equipment, relative to design specifications and operational expectations, as well as maintenance activity and service life estimates. BC Hydro has been working to ensure that these records are all up to date and has put in place monthly inter-unit meetings to discuss emerging equipment issues or unanticipated events that could affect asset performance and trigger needed action."

Summaries of the methodology and Transmission and Distribution asset health information are provided below.

2 Transmission and Distribution Asset Health Index

Asset Health Index is derived from operating, maintenance and asset management data. The methodology is described below.



The index is used to predict the asset's future performance and investment needs. Asset Health Index ratings and possible investment needs are:

Very Good	Normal maintenance
Good	Normal maintenance
Satisfactory	May require increased diagnostics and component replacement
Poor	Overhaul or replacement may be required within four to ten years
Very Poor	Overhaul or replacement may be required within three years

Asset Health Index can be grouped and analysed by asset class and/or criticality. Below are Asset Health Index charts for Transmission and Distribution asset classes as of April 2018:

Table N-1 Asset Health Index Summary

T&D Assets	Number of Assets (% of Total Assets)	% of Asset Replacement Value
		100 90 80 70 60 50 40 30 20 10
T&D Assets	4,056,320 (100%)	
Transmission	125,474 (3.1%)	
Substation	54,361 (1.3%)	
Distribution	3,876,485 (95.6%)	

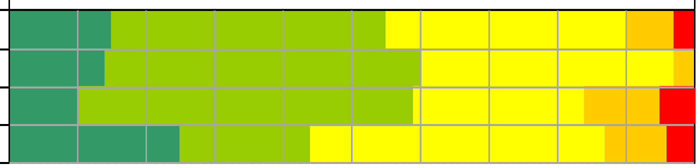


Table N-2 Asset Health Index for Transmission Line Assets

All Transmission Assets	Number of Assets	% of Asset Replacement Value
		100 90 80 70 60 50 40 30 20 10
All Transmission Assets	125,474	
1 - Metal Support Structures	24,259	
2 - Conductor Systems (km)	19,128	
3 - Wood Pole Structures	81,113	
4 - Underground Cables (km)	346	
5 - Line Disconnect Switches	309	
6 - Others	319	

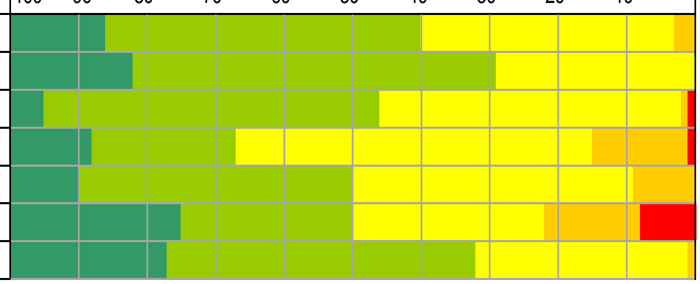


Table N-3 Asset Health Index for Substation Assets

All Substation Assets	Number of Assets
All Substation Assets	54,361
1 - Transformers	1,430
2 - Gas Insulated Switchgear	511
3 - Circuit Breakers	3,975
4 - Reactors	1,949
5 - Protection & Control Relay Systems	12,636
6 - Shunt Capacitors	434
7 - Disconnect Switches	14,172
8 - Instrument Transformers	8,454
9 - Series Capacitors	13
10 - HVDC Pole 2 (To be Obsolete)	1
11 - Surge Arrestors	6,177
12 - Synchronous Condensers	4
13 - Static VAR Compensator	5
14 - Station Insulators	435
15 - Standby Generators and Fuel Systems	75
16 - Mobile Transformers & Mobile Unit Substations	9
17 - Batteries	338
18 - Fire Protection Systems	155
19 - Voltage Regulators	363
20 - Others	3,225

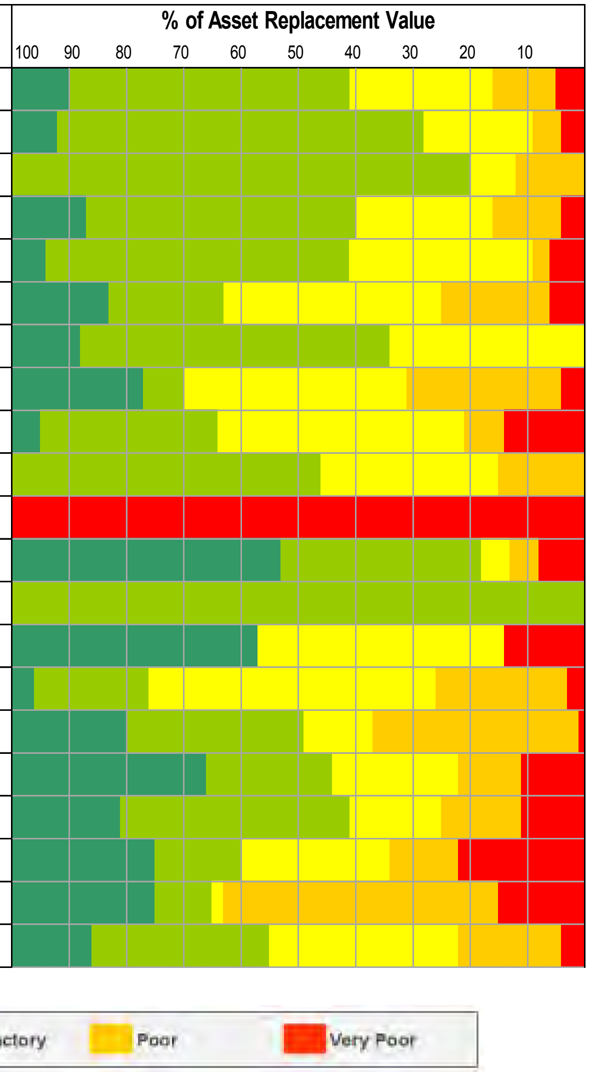
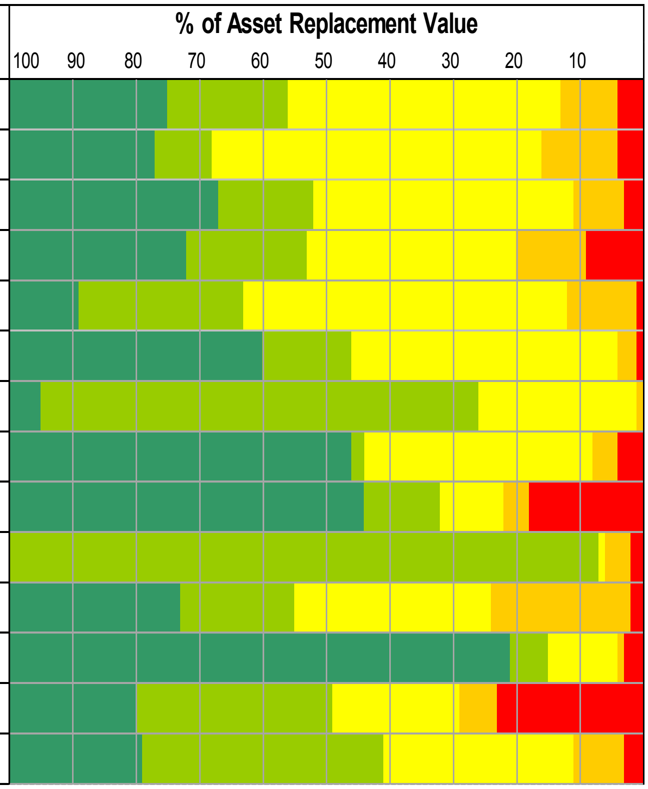


Table N-4 Asset Health Index for Distribution Assets

Distribution	Number of Assets
All Distribution Assets	3,876,485
1 - Distribution Poles	889,965
2 - Underground Transformers	66,658
3 - Overhead Transformers	282,176
4 - Overhead Primary Conductors (km)	48,413
5 - Underground Primary Cables (km)	10,780
6 - Revenue Meters	2,025,943
7 - Cutouts	406,939
8 - Overhead Switches	12,083
9 - Overhead Reclosers	1,330
10 - Street Lights	91,949
11 - Voltage Regulators	555
12 - Capacitors	425
13 - Others	39,268



Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix O

Electric Load Forecast Report
Fiscal 2019 to Fiscal 2024

Electric Load Forecast Report Fiscal 2019 to Fiscal 2024

October 2018

Load Forecasting
Energy Planning & Analytics
BC Hydro

BC Hydro
Power smart

Executive Summary

This report is a forecast of electricity sales to our customers and total gross system electricity requirements from F2019 to F2024. We developed the October 2018 Load Forecast for the F2020-F2022 Service Plan and the F2020-F2021 Revenue Requirements Application (F20-F21 RRA). This report is supplemental to the October 2018 Load Forecast information presented in chapter three of the F20-F21 RRA. Its purpose is to provide further information on the methodology and drivers underlying the results.

After introducing key concepts, we detail out the methodology and results of the component sector forecasts that make up the October 2018 Load Forecast. Where applicable, these methods and results are presented alongside an alternative forecast based on FortisBC Electric's short-term forecasting approach as applied to BC Hydro's context. We provide this additional analysis in light of the F17-F19 Revenue Requirement Application Decision's observation that other B.C. utilities use different forecast methodologies for the short term.

We begin with component forecasts for our major sectors:

- Residential
- Commercial
- Light Industrial
- Large Industrial

These sector forecasts are followed by details on the anticipated demand from emerging technologies: the cannabis and cryptocurrency industries and demand from electric vehicles. Sections 11 and 12 discuss the October 2018 Load Forecast uncertainties and provide an analysis of the challenges in estimating the electricity savings from codes and standards.

The summary table on the following page contains the results of our October 2018 Load Forecast on a billed sales basis from fiscal 2019 to fiscal 2024. In addition to developing this mid sales forecast, we also develop a total high and a low band around the mid forecast. The high and low bands are prepared using a Monte Carlo uncertainty model. The bands represent a range in future demands for electricity before savings from demand side management (DSM) and demonstrate some of the range of uncertainty.

In summary, our total firm sales forecast is expected to grow by 0.5 per cent per year[1] over the next six years, after adjusting for rate impacts and our DSM plan. Most of this growth is due to increased natural gas sales (in both upstream and downstream facilities) in the Large Industrial Sector. Large Industrial sector sales are forecast to grow by approximately 1.2 per cent per year. We are also forecasting a 1.5 per cent annual sales growth in the light industrial sector, primarily driven by expected growth in the emerging cannabis and cryptocurrency industries. Forecast residential sector sales are expected to experience relatively modest growth at 0.6 per cent per year. In contrast, commercial sector sales are expected to decline by 0.6 per cent annually over the forecast period. This decline is a result of slower projected growth in economic drivers, increases in the efficiency of how commercial customers use electricity, an update to the commercial model's calibration period, as well as the impacts of BC Hydro's DSM savings.

[1] Unless otherwise stated historical values and forecasts of electricity sales are computed on an annual compound basis.

October 2018 Load Forecast (Billed Sales) - After Rate Impacts and after Demand-Side Management[1]												
Fiscal Year	Main Customer Sectors					Other Loads				Low with DSM Total Domestic Sales (GWh)	Mid with DSM Total Domestic Sales (GWh)	High with DSM Total Domestic Sales (GWh
	Residential Sales (GWh)	Commercial Sales (GWh)	Light Industrial Sales (GWh)	Light Industrial & Commercial[2] Sales (GWh)	Large Industrial Sales (GWh)	Irrigation &Street Lights Sales (GWh)	Inter Utility Sales BC Hydro Sales to: City of New Westminster & FortisBC Electric Sales (GWh)	Total Firm Export BC Hydro Sales to: Seattle City Light & Hyder, Alaska Sales (GWh)	Total Domestic[3] Sales (GWh)			
Temperature Normalized Actuals												
F2013	17,852	14,333	3,994	18,327	13,530	292	795	310	51,107	51,107	51,107	51,107
F2014	17,928	14,343	4,164	18,507	13,972	293	949	308	51,957	51,957	51,957	51,957
F2015	17,973	14,460	4,227	18,687	14,055	296	966	305	52,283	52,283	52,283	52,283
F2016	18,019	14,257	4,148	18,405	13,698	322	971	308	51,724	51,724	51,724	51,724
F2017	17,952	14,582	4,275	18,856	13,106	312	1,053	318	51,597	51,597	51,597	51,597
F2018	17,997	14,513	4,364	18,877	13,513	308	1,017	312	52,024	52,024	52,024	52,024
Forecast												
F2019[4]	18,184	14,646	4,415	19,061	13,810	317	960	311	52, 643	51,754	52,643	53,546
F2020	18,253	14,484	4,487	18,971	14,702	311	1,012	312	53,561	52,239	53,561	54,901
F2021	18,324	14,352	4,683	19,036	14,243	312	1,027	312	53,253	51,365	53,253	55,190
F2022	18,411	14,244	4,688	18,931	14,066	313	1,057	314	53,090	50,836	53,090	55,399
F2023	18,551	14,113	4,697	18,810	14,371	314	1,076	312	53,434	50,674	53,434	56,279
F2024	18,709	14,034	4,697	18,731	15,414	314	1,071	312	54,552	51,252	54,552	57,952
History 5 Yr. Growtth[5] F13-F18	0.2%	0.2%	1.8%	0.6%	0.0%	1.1%	5.0%	0.1%	0.4%	0.4%	0.4%	0.4%
Forecast 5 Yr. Growth[5] F18-F23	0.6%	-0.6%	1.5%	-0.1%	1.2%	0.4%	1.1%	-0.1%	0.5%	-0.5%	0.5%	1.6%

Table notes:

1. All forecast values includes all load reductions for rate impacts, DSM savings, and savings from loss reductions.
2. Light Industrial/Commercial is the sum of the loads in the light industrial sector and commercial sector.
3. Total Domestic Sales is the sum of the loads from the Main Customer Sectors and Other Loads.
4. The forecast for fiscal 2019 reflects six months of actuals billed sales and six months forecast on a billed sales basis.
5. Growth rates are computed on an annual compound growth basis over five years.

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1.0 Introduction

BC Hydro is the third largest utility in Canada and serves 95 per cent of British Columbia's population. BC Hydro's total energy requirements, including losses and sales to other utilities and non-integrated areas (NIAs), were 57,842 GWh in fiscal 2018. Excluding the NIAs, the total integrated system energy requirements were 57,527 GWh.

Load forecasting is central to BC Hydro's long-term planning, medium-term investments, and short-term operational & forecasting activities. BC Hydro's Electric Load Forecast is developed for the purpose of providing decision-making information for electricity rates, as well as where, when, and how much electricity we expect to need from the BC Hydro system. About two thirds of the forecast is based on Statistically Adjusted End Use (SAE) econometric (regression) models that use historical billed sales data combined with economic forecasts and inputs from internal, government and third party sources. The other one third of the forecast is derived from individual forecasts of our large industrial customers.

BC Hydro's load forecasting activities are focused on the preparation of a number of time and location specific forecasts of energy sales requirements in order to provide information for decision makers.

Given the variety of uses, our load forecast consists of a suite of forecasts, each of which fulfills different user requirements. For example, integrated system energy planning considers system losses associated with delivering energy from generation resources to our customers, but not the forecast demand from customers that are not connected to our integrated system (i.e., this is referred to as our total integrated gross system requirements). Revenue forecasting includes all customer demand (i.e., domestic sales, including non-integrated customers, sales to other utilities, and firm exports), but does not consider losses or BC Hydro's own use. In addition, the British Columbia Utilities Commission (BCUC) requires us to separately reflect the impacts associated with future electricity price increases (rate impacts) and demand side management plan (DSM) savings. Rate impacts are load reductions estimated using price elasticity and bill impact projections in real dollars (net of inflation). The projection of bill impacts reflected in the October 2018 Load Forecast is based the last five years of the 2013 Ten-Year Rates Plan.

We develop high and low uncertainty bands which represent ranges around the mid or expected forecasts at certainty levels of statistical confidence. These high and low uncertainty bands are produced because there is uncertainty in the input variables that predict future loads and in the predictive capabilities of the forecasting models themselves.

BC Hydro developed the October 2018 Load Forecast for its annual Fiscal 2020-Fiscal 2022 Service Plan and the Fiscal 2020-Fiscal 2021 Revenue Requirements Application (i.e., F20-F21 RRA). The October 2018 Load Forecast presented in this report is a forecast of electricity sales by customer sector and total gross system electricity requirements from fiscal 2019 to fiscal 2024. The CleanBC Plan, released by government in December 2018, is not reflected in the Load Forecast which was finalized in October 2018. By 2030, the CleanBC Plan could require approximately 4,000 gigawatt-hours of energy over and above currently projected demand growth to electrify key segments of the economy. Some of the implications of this include a further commitment to electric vehicle incentives which may mean more electric vehicle sales and associated loads, increased building load, and increased natural gas sector load. This information will be incorporated in our future forecasts.

Following the BCUC's requirements, we produce three types load forecasts:

- before considering rate impacts, DSM and loss reductions,[2]
- after considering rate impacts, but before DSM and loss reductions, and
- after considering rate impacts, DSM and loss reductions.

[2] Loss reductions were referred in our F2017 to F2019 Revenue Requirements Application as Var and Voltage Optimization (VVO) savings.

The Load Forecast information presented in chapter three of the F20-F21 RRA is our forecast of sales after taking into account rate impacts, incremental DSM savings and savings from our loss reductions program, which account for efficiencies at BC Hydro's distribution substations to minimize line losses. The loss reduction program is separate from our DSM plan.

This report is supplemental to our October 2018 Load Forecast contained in our F20-F21 RRA. BC Hydro develops an electricity sales forecast for each of its main customer sectors including: residential, commercial, light industrial, and large industrial. We also develop a forecast of electricity sales to other utilities and firm exports supplied by BC Hydro. The methods and forecasts for each sector as well those for other utilities and firm exports are the focus of this report. Where vintages of forecasts are compared, the October 2018 Load Forecast is contrasted with the May 2016 Load Forecast – our last 20-year forecast.

This report details the methodology and results of our October 2018 Load Forecast on a billed sales basis as historical billed sales data from our billing system underpins our load forecast methods. Our F20-F21 RRA presents the Load Forecast on an accrued sales basis because accrued sales are used to estimate revenues on a monthly and fiscal year basis. An explanation of the difference between billed and accrued sales forecasts is provided in Section 2.2.3.

The next section provides an overview of the components and steps involved in developing our total gross system requirements forecast. This is followed by a discussion of methodology improvements we have incorporated into the October 2018 Load Forecast. After the methodology discussion, the forecasts for each customer sector are summarized. Where applicable, these methods and results are put alongside an alternative forecast based on FortisBC Electric's short-term forecasting approach as applied to BC Hydro's context. We provide this additional analysis in light of the F17-F19 RRA Decision's observation that other B.C. utilities use different forecast methodologies in the short term. Finally, each sector's risk and uncertainties are discussed.

The customer sector forecasts are followed by details on the anticipated demand from emerging sub-sectors and technologies: the cannabis and cryptocurrency industries, and demand from electric vehicles. This is followed by our forecast uncertainty bands as determined by our Monte Carlo uncertainty model and a discussion on the integration of codes and standards between our forecasting methods and our DSM plan where code and standards are common to both.

Finally, the most detailed information is available in the appendices supplementing each section. They include:

- a comparison between the October 2018 Load Forecast and the May 2016 Load Forecast,
- a general description of the SAE model and equations,
- improvements to the SAE models,
- the summary statistics and regression results of our October 2018 SAE models,
- our temperature normalization procedures for the residential and commercial sectors and residential accounts improvements,
- economic and other drivers of the forecasts, and
- summary tables containing the October 2018 Load Forecast.

2.0 Load Forecast Components

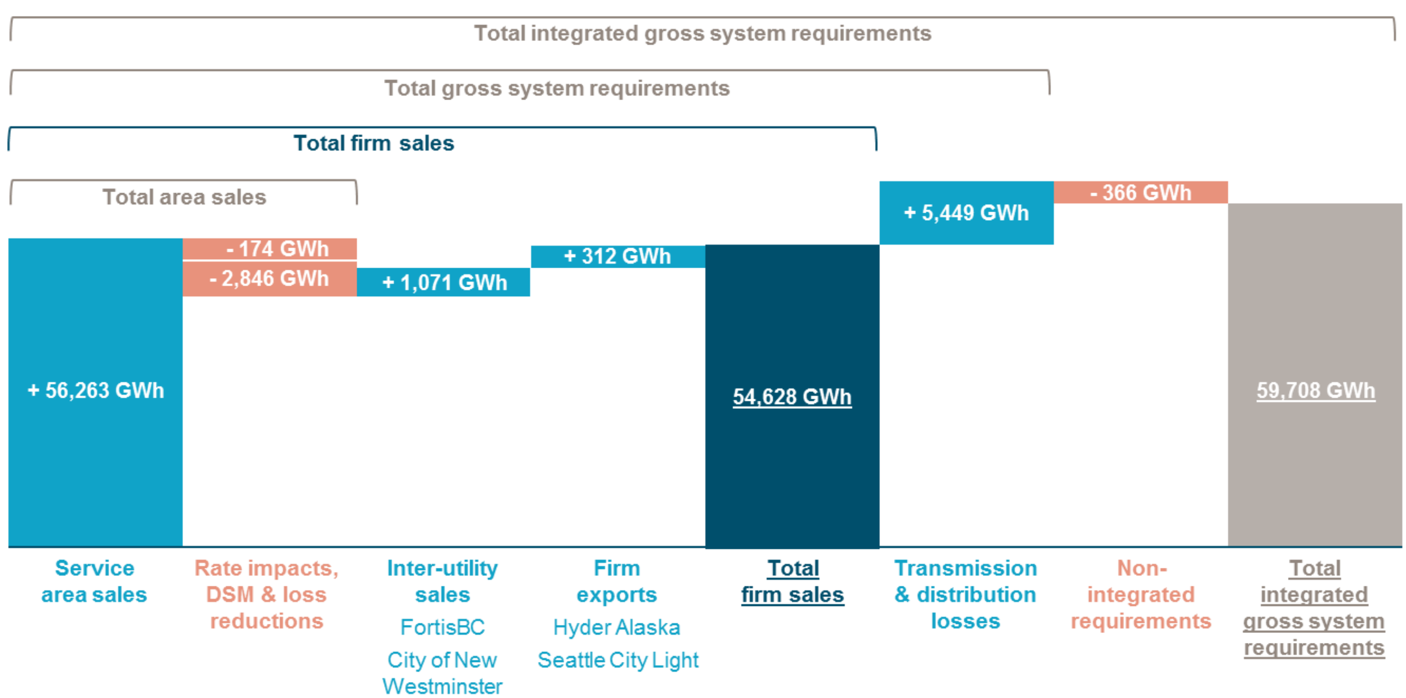
The highest level of our forecast is called the integrated gross system requirements. It is used to optimize operation of our system in the short-term and to plan our system over the long-term. For short-term analysis, the forecast is used by BC Hydro's Generation System Operations business unit in monthly energy studies. The analysis from these studies yields a forecast of the volume of market purchases and costs of market purchase, which is part of the total cost of energy included in our revenue requirements applications.

The forecast of BC Hydro's total gross system requirements is built up from a series of components and steps, including:

- A forecast of electricity sales to all customers in our service area (service area sales). This includes a forecast for our main customer sectors (i.e., residential, commercial, light industrial and large industrial) and other loads including street lighting customers, irrigation customers, and electricity used by BC Hydro assets, such as distribution substations. We refer to this BC Hydro asset-related consumption as BC Hydro own use,
- A forecast of electricity sales to other utilities supplied by BC Hydro under contracts and tariffs. Service area sales plus sales to other utilities results in total firm sales, and
- A forecast of system distribution and transmission losses (i.e., total losses). Total firm sales and total losses results in total gross system requirements.

Figure 2.1 illustrates the build-up of our forecast of total gross system requirements and integrated total gross system requirements based on one of the three forecast types, namely: after taking into account rate impacts and savings associated with our DSM plan and loss reductions program.

Figure 2-1 Build-up of Total Integrated Gross System Requirements Forecast after Rate Impacts, DSM and Loss Reductions for Fiscal 2024



The loads used to develop each of the major components of total integrated gross system requirements are summarized in the following sections.

2.1 TOTAL AREA SALES

The forecast of our service area constitutes most of our main customer sectors (i.e., residential, commercial, light industrial, large industrial, etc.) and involves the most significant aspects of our load forecasting process. Each customer sector is developed using the following steps.

2.1.1 Model projections are used for each main customer sector

Model projections are forecasts for our main customer sectors: residential, commercial, light industrial, and large industrial. These are laid out in the early sections of this document:

- Section 4 outlines our projections of electricity sales to the residential sector,
- Section 5 outlines our projections of electricity sales to the commercial sector,
- Related to the residential and commercial sector model projections:
  - Section 12 describes the adjustment to account for a potential double counting because of an overlap in codes and standards. This overlap occurs because there are energy savings from codes and standards that are reflected in both our DSM plan and the US Energy Information Administration (EIA) assumptions included in the SAE model.
- Section 6 outlines our electricity sales forecast to the light industrial sector, and
- Section 7 outlines our electricity sales forecast for the large industrial sector. The industrial sector forecast is a summation of the individual customer forecasts for about 190 large industrial customers.

2.1.2 Load additions

In addition to our model projections, unique customer segments and technologies are also added in our customer sector forecasts:

- expected loads for the cannabis and cryptocurrency customer segments are included in the light industrial and large industrial sector and described in Section 8,
- a forecast of electric vehicle load, included in our residential and commercial sector forecasts, is outlined in Section 9,
- fuel switching loads based on specific government or BC Hydro programs that incent customers to switch from fossil fuel-based energy to clean electricity are added to the residential, commercial, light industrial and large industrial sectors, and
- construction loads are included in the light industrial sector.

2.1.3 Load reductions

Service area loads are reduced to account for rate impacts, DSM savings and loss reductions.

Load reductions that result from rate impacts are calculated separately for each of our main sectors. Rate impacts are based on:

- an electricity price elasticity of -0.1 applied to the major sectors including residential, light industrial, commercial, and customers that make up the large industrial sector, and
- a projection of real dollar (i.e. net of inflation) bill impacts informed by the last five years of the 2013 Ten-Year Rates Plan.

The incremental savings from our DSM plan and loss reductions program are also computed separately for each customer sector and at the BC Hydro service area level. The forecast of DSM savings reflected in our October 2018 Load Forecast is based on our latest DSM plan, which is included in our F20-F21 RRA. DSM savings from fiscal 2019 to fiscal 2024 are based on incremental activities to the fiscal 2018 base year which was the last year of actual sales.

BC Hydro's DSM plan is comprised of a number of initiatives that have the objective of reducing customers' energy consumption and by doing so, reducing their electricity bills. The main components of BC Hydro's DSM plan are:

- Programs: Programs are available to all customer sectors and deliver a mix of information, access to technology and services, technical assessment and support, and financial assistance to all customer classes to address barriers to cost effective DSM. Programs are designed to capture additional DSM potential that remains beyond that obtained from codes and standards and rate structures.
- Codes & Standards: Codes and standards refer to a range of government policy instruments that influence the use of energy, including product/equipment regulations, building codes, tax measures. BC Hydro supports the development of these codes and standards and also works with communities on municipal zoning/building permitting processes, as well as enhanced approaches for Indigenous and remote communities.
- Rates: Rate structures are changes to the design of electricity rates to provide more economically efficient price signals to customers which encourage conservation. BC Hydro currently has conservation rate structures in place for residential and large industrial (transmission voltage) customers.
- Supporting Initiatives: Supporting initiatives include public engagement and awareness activities and general management and infrastructure.

The forecast of loss reductions are developed for our distribution system and are also incremental to the fiscal 2018 base year. Loss reductions are applied to residential, light industrial and commercial sectors on load share basis.

2.1.4 Other elements of service area

Forecasts for other small loads such as irrigation customers, street light customers and BC Hydro's own use are developed separately and these forecasts are included as part of our total area sales. With the exception of BC Hydro own use, all of these loads are developed with trend analysis.[3] The forecast of BC Hydro own use is developed with trend analysis for the base load and supplemented with additional construction load for the Site C Project. The construction loads are based on estimates provided to BC Hydro from the various contractors involved in the construction of the Site C Project. The details of the trend analysis and forecast results for these other loads are not covered in this report.

2.1.5 Inter-utility sales and firm exports

The next component represented in Figure 2-1 includes sales to the City of New Westminster and FortisBC Electric. Sales to these two utilities make up total inter-utility sales. Sales to Seattle City Light and Hyder, Alaska make up total firm exports. Rate impacts using the same price elasticity and bill impact projections as described above are applied to loads from the City of New Westminster and Hyder, Alaska. Sales to Seattle City Light are determined by a treaty and as such rate impacts are not applied. For sales to FortisBC Electric, rate impacts are built into a methodology that determines the electricity sales. That methodology and the forecasted inter-utilities sales and firm exports are detailed in Section 10. The combined forecast of inter-utilities sales, firm exports, and total area sales is the forecast of total firm sales.

2.1.6 Transmission and distribution losses

Transmission and distribution losses are developed by applying loss factors to the individual loads that make up total firm sales. These loss factors result in a forecast of system wide losses which are close the average of actual system wide losses (i.e., transmission and distribution). The actual transmission & distribution losses are calculated as the difference between actual total system gross system requirements and actual total firm sales.

[3] The forecast is based on historical growth trends. BC Hydro is in the process of approving its business case to replace street lights with LED technology. The potential roll-out of this program will not have a material impact on the total load over the forecast period (expected to be about 20 GWh/year), but will be monitored for impacts to future load forecasts.

With the forecast of transmission and distribution losses in hand, total gross system requirements, as shown in Figure 2-1, is arrived at by adding total firm sales.

2.1.7 Total integrated gross system requirements

Finally, total integrated gross system requirements is calculated by reducing total gross system requirements by the portion of sales and losses from loads in our Non-Integrated Areas (NIA). Section 10 defines NIA and its forecasts.

2.2 TYPES OF LOAD FORECASTS

2.2.1 BCUC required forecasts

Following the BCUC Resource Planning Guidelines, BC Hydro develops three types of forecasts:

- before considering rate impacts, DSM and loss reductions,
- after considering rate impacts, but before DSM and loss reductions, and
- after considering rate impacts, DSM and loss reductions.

These forecast types allow us to identify the specific effects associated with future electricity price (rate) increases and DSM savings. Each type is calculated as a mid (expected) load for each of the forecast components outlined previously in Section 2.1.

For example, we have three forecasts of total firm sales:

- the forecast of total firm sales before rate impacts includes all model projections for main sectors, adjustments, load additions, forecasts for irrigation customers, street lights customers, BC Hydro own use, and sales to inter-utilities and firm exports,
- the forecast of total firm sales after rate impacts is the same, but also includes the effects of rate impacts, and
- the forecast of total firm sales after DSM and loss reductions is the same as total firm sales after rate impacts, but includes load reductions for DSM and loss reductions savings.

This convention for naming the three types of forecasts is used through the rest of the document.

When each of the other forecast components is calculated in the same three ways, they can be combined to make up three types of total gross system requirement and integrated gross system requirements, and the results for these forecasts are summarized in tables contained in Appendix G of this report.

2.2.2 Forecasts to characterize uncertainties

To quantify the various uncertainties in the factors that increase or decrease load, BC Hydro develops a high and a low uncertainty band around our mid forecast after rate impacts. The high and low uncertainty band, for each year of the forecast, comes from our Monte Carlo uncertainty model and a simulation process. The details of our Monte Carlo uncertainty model, the equations of the model, and the results of the model are contained in Section 11 of this report.

2.2.3 Billed and accrued sales forecasts

Total billed domestic[4] sales after load reductions for rate impacts, DSM, and loss reductions savings is the foundation of our electricity sales projections for our revenue requirements with one exception. The forecasts for the residential, light industrial and commercial sectors are developed on an accrued sales basis for our revenue requirements application because accrued sales are used to estimate monthly and fiscal year revenues for these sectors.

[4] Domestic sales are total area sales, excluding BC Hydro own use, and sales to inter–utilities and firm exports.

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In general terms, historical billed sales represent what was billed to our customers in a month and over a fiscal year in line with our billing cycle, while historical accrued sales are estimates of actual electricity consumption in a month and over a fiscal year. Our forecasts are based on relationships between load drivers and billed sales. As such, the forecast of future customer loads are in the form of billed sales projections. Revenue projections from these future loads are based on accrued sales which are estimates derived from monthly billed sales. As such, the forecasts of future loads for our customers in our revenue requirements application are in the form of accrued sales.

The electricity sales data contained in this report is different to sales data contained in Chapter 3 of our F20-F21 RRA. These differences occur in the following areas:

First, all of the history and forecasts for the residential, light industrial / commercial, and large industrial sectors contained in this report are on a billed sales basis. All of the history and forecasts for these sectors in our F20-F21 RRA are on an accrued sales basis, with the exception of the large industrial sector where the forecasts for this sector as shown in our F20-F21 RRA is on billed sales basis.

Secondly, all history and forecasts for light industrial and commercial sectors in this report are shown separately on a billed sales basis. Our F20-F21 RRA shows the combined total history and forecasts of the light industrial and commercial sector and it refers to the combined sector as the light industrial / commercial sector.

Finally, the summary tables in Appendix G of this report contain total firm billed sales and total domestic billed sales. Total domestic sales are total area sales, excluding BC Hydro own use, and sales to other utilities and firm exports. BC Hydro own use is not included in our calculation of revenues. Summary tables in our F20-F21 RRA contain total domestic sales on accrued sales basis.

2.2.4 Consideration of an alternative forecast

We developed alternative forecasts for the residential and commercial sectors in response to commentary in the BCUC's F17-F19 RRA Decision. We found that the results based on forecasts using the alternative methodology did not perform better than those derived from our approach. Further details on the comparison between the forecasts developed using the alternative method and the forecasts developed with our approach for the residential and commercial sectors are contained in sections four and five respectively.

In the F17-F19 RRA Decision, the BCUC noted that some utilities in B.C. use a different load forecast methodology in their short term forecast for setting rates. We reviewed the short term load forecast methodologies of Fortis BC Energy Inc. (Gas), FortisBC Electric, Pacific Northern Gas West, and PNG Gas East. We selected FortisBC Electric as a comparable alternative because it is the other major regulated electric utility in B.C. In addition, we found their methodology compatible with our customer data, allowing for a more direct comparison between our methodology and theirs.

The table below compares our current methodology to that of FortisBC Electric.

Table 2-1 Comparison of BC Hydro's and FortisBC Electric's Short-Term Load Forecast Methodologies

Sector	BC Hydro October 2018 Load Forecast methodology	FortisBC Electric short term methodology
Residential	An SAE model is used to forecast average use per residential account in each of BC Hydro's four major service regions. Refer to Section 4.2.3.1 for more information on the residential SAE model. The account growth is based on historical ratio of accounts growth to housing growth and housing growth forecasts, which are provided by the Conference Board of Canada, June 2018 Economic Forecast.	The forecast of average use per account is established with a three year historical trend line of temperature normalized use per account. The time trend is assumed to continue into the future to develop the forecast. The residential account forecast is based on a regression of historical accounts and population statistics which are provided by BC Statistics.

Commercial	SAE models are used to forecast electricity sales for both small commercial customers and large commercial customers in each of BC Hydro's four major service regions. Refer to Section 5.2.1 for more detail on the commercial SAE model.	The commercial sector forecast is based on a regression analysis of load to provincial GDP. The GDP forecast is provided by the Conference Board of Canada.
Large Industrial	BC Hydro has approximately 190 large industrial customers, and forecasts load for this sector is developed for each customer. Forecast load for each account is developed using a probabilistic assessment of future customer sales. This assessment relies on intelligence from external consultants who are industry and/or plant experts, as well as third party market subscription services. The assessment also relies on customer information provided by BC Hydro's key account managers who liaise directly with our customers. Based on the probability weighting for each customer, BC Hydro makes an "in or out" call on the variability of each account for the test period years. The methodology for the large industrial sector is explained in more detail in Section 7.2 of this report.	FortisBC Electric has approximately 50 large industrial customers. Forecast load for these customers is developed based on confidential updates shared by customers through surveys conducted by FortisBC Electric. Where customer information is not available, FortisBC Electric applies GDP growth rates to each of its customers.

We did not develop an alternative large industrial forecast based on the FortisBC Electric method. Both utilities use customer information to develop their respective large industrial sector forecasts, making a direct comparison impossible. In addition, Section 7 shows how our large industrial forecast methodology goes beyond just customer information in our attempts to refine the performance of our large industrial forecast.

3.0 Improvements to the Load Forecast

In this section we address improvements since the May 2016 Load Forecast, which were a product of our continuous improvement efforts, and feedback from a BC Hydro internal audit as well as two BCUC reviews. Significant improvements, which are discussed in Section 3.2, include:

- changes to the Liquefied Natural Gas (LNG) forecast methodology,
- SAE model improvements,
- residential sector accounts forecast, and
- adjustments to price elasticity values.

3.1 EXTERNAL REVIEWS OF THE LOAD FORECAST SINCE THE MAY 2016 FORECAST

An August 2017 audit of our load forecasting function endorsed the overall load forecast methodology, while making some recommendations on how to improve, which have been incorporated into the October 2018 Load Forecast.

The audit of our load forecasting function was completed by BC Hydro Audit Services (Load Forecasting Audit). The objective was to review load forecasting processes to ensure timely and reliable forecasts. A copy of this audit is included as Appendix P in our F20-F21 RRA.

The audit relied on an independent subject matter expertise from GDS Associates Inc. GDS is a U.S. based firm with experience with load forecasting in the electrical utility industry. The principal at GDS who undertook the work has over 30 years of load forecasting experience. His knowledge included preparing load forecasts for utility clients (ranging from day-ahead to annual and long-term time frames), and filing regulatory testimony related to load forecasting and statistical analyses.

GDS's findings, which were adopted by the Load Forecasting Audit, included:

- "Overall, the load forecasting function at BC Hydro compares favorably to industry standards and to other large electric utilities in North America. No critical weaknesses were found."
- "Load forecasting methodologies are consistent with best practices and load forecast outputs are provided to users and stakeholders on a timely basis."
- "The greatest risk of load forecasting inaccuracy falls on the industrial class and is due to the uncertainty of future economic activity and the volatility of many individual customer loads."
- "Areas for improvement identified primarily relate to making adjustments to forecast models and inputs to enhance overall forecast accuracy."

The Load Forecasting Audit included recommendations focused on adjustments to our models and inputs that could improve forecast performance. For example, the audit recommended that we "accelerate internal studies and development on the elasticity coefficients used in the development of the Load Forecast, including price elasticity and statistical adjusted end-use (SAE) model elasticity." As discussed next, we have addressed the audit recommendations.

In addition the Load Forecasting Audit discussed above, two BCUC reviews have occurred since the May 2016 Load Forecast:

- **August 2017, Fiscal 2017 – Fiscal 2019 Revenue Requirements Application Decision:** The BCUC found that BC Hydro's May 2016 Load Forecast was, "reasonable for use for the F2017 to F2019 test period", but acknowledged concerns regarding price elasticity and historical load forecast accuracy.[5]
  - The BCUC acknowledged BC Hydro's observation that electricity rate increases, "were known to industrial customers when BC Hydro's key account managers conducted their forecast surveys. Accordingly, [the BCUC was], "satisfied that the issue of price elasticity for future, unknown price increases [was] not an issue in the test period."[6]
  - The BCUC further noted that some utilities use a, "different load forecast methodology for their short term forecast for setting rates as compared to [their] long-term forecast for resource planning."[7]
- **November 2017, Site C Inquiry Final Report**: The Inquiry focussed on long-term demand as opposed to the short-term forecast for a particular test period. However, the BCUC identified a number of issues related to BC Hydro's Load Forecast, including:
  - The accuracy of the industrial forecast and, in particular that, "BC Hydro had not made a probabilistic assessment of the likelihood of the LNG load materializing."[8]
  - "GDP[9] and disposable income estimates used by BC Hydro in its Current Load Forecast are higher than similar Conference Board of Canada estimates."[10]
  - For price elasticities, "long-run price elasticity used by BC Hydro for all rate classes to be too low in magnitude."[11]

Table 3-1 provides a summary of Load Forecasting Audit and BCUC issues raised and how they have been addressed.

[5] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), Appendix B, page 12.
[6] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), Appendix B, page 6
[7] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), Appendix B, page 11.
[8] BCUC Inquiry Respecting Site C – Final Report (November 1, 2017), page 78.
[9] All instances of GDP are Real GDP and not Nominal GDP.
[10] BCUC Inquiry Respecting Site C – Final Report (November 1, 2017), page 78.
[11] BCUC Inquiry Respecting Site C – Final Report (November 1, 2017), page 79.

Table 3-1 Summary Consideration Table of Load Forecasting Issues Raised

Issues	BC Hydro's Consideration
BCUC Fiscal 2017 – Fiscal 2019 Revenue Requirements Application Decision	
1) "[BCUC] Panel acknowledges the concerns of AMPC regarding price elasticity use for industrial customers," but is nevertheless "satisfied that the issue of price elasticity for future unknown price increases is not an issue in the test period."[12]	BC Hydro engaged DNV GL Consulting to review price elasticity and recommended increasing elasticity values from (0.05) to (0.1) and applying price elasticity across all customer sectors. Recommendation adopted.
2) "[BCUC] Panel notes there is a need to accurately predict the next three years."[13]	Implemented the following improvements to our forecasting methods: **Industrial**: • Applying binary call to large industrial probability based method for first three years of the load forecast. • Revised LNG forecast method to be consistent with large industrial sector methodology. • Retained third party consultant to support natural gas sector market forecast. **Residential and Commercial Models:** • Work completed with model vendor (ITRON) to update relationships between economic drivers and electricity use as well as temperature and electricity use.
3) "[BCUC] Panel notes that other utilities such as Pacific Northern Gas, FortisBC (natural gas) and FortisBC (electricity) use a different load forecast methodology for their short term forecast for setting rates as compared to its long term forecast for resource planning."14	We compared alternative short term methodologies and have included result based on the FortisBC (electricity) method as an alternative forecast for the residential and commercial sectors.
Load Forecasting Audit Findings	
1) Economic/Industrial Outlooks: Request industrial and economic consultants to provide explanations and/or reasons for the variances between outlooks provided and actual output once actual or estimated data becomes available.	Consultants are now required to provide an explanation of variances to actuals when available.
2) Market Research: Consider conducting residential customer surveys once every three years if the key trends being measured are not changing significantly over time.	Determined there is a need to continue with both residential and commercial end-use survey.

[12] BCUC Decision on BC Hydro's F2017 to F2019 Revenue Requirements, Appendix B, page 6.
[13] BCUC Decision on BC Hydro's F2017 to F2019 Revenue Requirements, Appendix B, page 11.
[14] BCUC Decision on BC Hydro's F2017 to F2019 Revenue Requirements, Appendix B, page 11.

3) Specific Input Assumptions: Accelerate internal studies/development on: • The stock and flow model • Elasticity coefficients updates used in the development of the load forecast; including price elasticity and SAE model elasticity	A stock and flow model (beta version) has been completed and in the process of calibration. DNV GL Consulting reviewed price elasticity and recommended increasing elasticity from (0.05) to (0.1) and applying price elasticity across all customer sectors. Recommendation adopted. Residential and Commercial Models: Work completed on relationship between economic drivers and electricity use.
BCUC Site C Inquiry Final Report	
1) [BCUC] "Panel agrees with several parties who express concern with the fact that BC Hydro has not made a probabilistic assessment of the likelihood of the LNG load materializing"[15]	Revised LNG forecast method to be consistent with large industrial sector methodology.
2) [BCUC} "Panel finds the GDP and disposable income estimates used by BC Hydro in its Current Load Forecast are higher than similar Conference Board of Canada estimates."[16]	As part of BC Hydro's normal competitive procurement practices, the Conference Board of Canada was the successful proponent on an RFP for economic consulting services to provide us with a sub-regional and aggregate economic forecast for the province.
3) [BCUC] "Panel finds that the historical instances of over-forecasts are greater than under-forecasts, especially in the industrial load, and that the accuracy of BC Hydro's historical industrial forecasts looking out three and six years has been considerably below industry benchmarks."[17]	Current five year forecast is made up of a higher percentage of high probability/committed projects compared to previous forecast which included lower probability projects. Implemented the follow improvements to our forecasting methods: • Applying binary call to large industrial probability based method for first three years of the load forecast. • Retained third party consultants to support natural gas sector market forecast

3.2 LOAD FORECAST METHODOLOGY CHANGES

The following sections outline the forecast methodology changes since the May 2016 Load Forecast.

3.2.1 Large industrial sector: using a binary approach instead of probability weighting for early years

An improvement in the October 2018 Load Forecast is to move away from a probability weighted forecast for large industrial customers over the early term of the to a full load or no load binary approach. This means that the probability weighting, which we develop for each customer, is used to inform an "in" or "out" call for each customer in the first three years of the forecast. Customers with a greater than or equal to 50 per cent weighting are included in the forecast at their full anticipated load. Customers falling below that probability are excluded from the forecast for all years of the forecast. For example, a customer with a low probability weighting - say a 25 per cent probability - would not be included.

[15] BCUC Inquiry Respecting Site C – Final Report (November 1, 2017), page 78.
[16] BCUC Inquiry Respecting Site C – Final Report (November 1, 2017), page 78.
[17] BCUC Inquiry Respecting Site C – Final Report (November 1, 2017), page 78.

The binary method results in discrete projection (i.e. in or out) of load and revenues. Given that we have good information to make the binary call, we believe forecasting load in this manner is preferred over the test years rather than having partial load and partial revenue projections. Beyond fiscal 2021, the methodology for the large industrial customers is unchanged from the May 2016 Load Forecast methodology. For further details on the methodologies for the large industrial sector please see Section 7 of this report.

3.2.2 Large industrial sector: LNG forecast methodology

In the May 2016 Load Forecast, we included the load that LNG proponents announced would be supplied by BC Hydro and the dates they expected to require service. These loads were not probability weighted. For the October 2018 Load Forecast, the forecasts for LNG plants is consistent with the methodology applied to all other large industrial customers just described in the previous section. That is, the forecast of LNG plants' loads are now based on a binary call of 'in or out' for the first three years from fiscal 2019 to fiscal 2021 and by a probability assessment from fiscal 2022 and beyond. Further details on the LNG plants' loads included in our October 2018 Load Forecast period is provided in Section 7.

3.2.3 Residential and commercial sectors: SAE model improvements

We updated all of our SAE models for the relationship between load and temperature. This work involved updating the temperatures at which these customers respond to colder temperatures (with heating) and warmer temperature (with cooling). These temperatures vary by region within British Columbia. This work was undertaken using aggregated customer load profiles developed using a load shape model and electricity consumption data from our smart meters. Additional details on the results of this temperature and load analysis are discussed in Appendix C.

The updates to our parameters and load temperature relationships are intended to enhance forecast accuracy because: (i) they reflect the most recent information gathered over the past 10 years ending fiscal 2018 which is our SAE model estimation period; and (ii) they use smart metering infrastructure (SMI) data to improve accuracy rather than a limited number of representative samples from customer hourly metered data we relied on before SMI data was available.

In addition to updating the parameters on the load and temperature relationship, we re-calibrated the relationship between economic variables and load (i.e. economic elasticities) for the various economic variables in our all of SAE models. This work was completed in response to the Load Forecasting Audit recommendations. The revised economic elasticities are summarized in Appendix C of this report. The revised elasticities are relatively small and consistent with our observations of a lower growth in load and higher growth in the economy over recent years.

3.2.4 Residential sector: accounts forecast

BC Hydro has modified its methodology on how we forecast the number residential accounts. Previously, we assumed that there was a one-to-one relationship between housing growth and growth in BC Hydro residential accounts. We used a historical analysis of recent account growth and housing growth and concluded that a more appropriate average ratio is 0.9 new accounts per unit of housing growth. We updated our methodology to reflect this, and the details of that implementation and a comparison to previous account forecasts are in Appendix E of this report.

3.2.5 Main sectors: electricity price elasticity of demand

The need to review and update our price elasticity assumption was a finding from the Load Forecasting Audit, the previous application's proceeding, and the Site C Inquiry. In March 2018, BC Hydro retained DNV GL Consulting to conduct an electricity price elasticity study for each of our customer sectors. DNV GL Consulting is a global quality assurance and risk management company, with a highly regarded energy advisory services division offering institutional, legal and technical expertise on electricity systems, supplies, regulations and standards. The company has global operations in over 100 countries. The results of their price elasticity study are included as Appendix Q (Elasticity Study & GDP Study) of our F20-F21 RRA.

DNV GL Consulting's key findings, which were adopted for this forecast, included:

- "In our survey, the most commonly reported price elasticity for the residential sector is -0.10. While values as low as -0.06 and as high as -0.26 are in use among the utilities we reviewed, the most commonly reported value is a useful indicator of typical consumer response to rate changes. The -0.10 value is also most commonly reported for the two other sectors. Further, this value (-0.10) was recently recommended in an expert testimony to the Manitoba Public Utilities Commission presented in the table above."
- "Values from external sources as well as those determined by BC Hydro from its own and neighbouring utility data, indicate a residential price elasticity value that centres on -0.10 is a reasonable value for BC Hydro's residential customers. Therefore, we recommend that BC Hydro increase the price elasticity in use to assess rate impact and determine load forecast growth for the residential customers. Based on the convergence of values, we find an increase to -0.10 to be reasonable."
- "In general, we find BC Hydro's application of price elasticity to be consistent with that of many of the Canadian and U.S. utilities we reviewed. DNV GL supports the continuation of BC Hydro's approach to load forecasting which involves building up sector specific forecasts, including site-specific large commercial and industrial forecasts, and applying a single price elasticity to account for price changes in the forecast. Given that BC Hydro employs a site by site assessment for industrial facilities which captures price effect for a selection of energy intensive facilities, such as pulp mills; and precedent elsewhere, of applying the same price elasticity across all three sectors, we recommend that BC Hydro continue to use the same price elasticity estimate for all sectors."

The GNV DL Consulting study results, combined with the results of our own evaluation of the residential inclining block rate (fiscal 2013 to fiscal 2017), supports the results of previous internal studies and third party assessments that our price elasticity estimates are consistent with what is commonly reported and on the lower end of the survey data.

BC Hydro has increased the electricity price elasticity value from -0.05 to -0.10.The revised price elasticity is used to determine rate impacts for the main customer sectors which is reflected in the October 2018 Load Forecast.

3.2.6 Oil and gas sector: additional consultant services

Previously we had not relied on external subject matter experts to provide analyses of B.C. shale gas development. However, for this forecast we recognized the shale gas component of the oil and gas sub-sector as the fastest growing area of our sales, and retained the services of an oil and gas consulting company. Their western Canadian expertise served to provide industry intelligence to improve the accuracy of our assumptions, with a focus on:

- Montney shale gas development in B.C. (in light of competition with Alberta),
- oil and gas and gas liquids price forecasting,
- oil sands development (which will consume much of B.C.'s natural gas and gas liquids), and
- assessing the shale gas plants in BC Hydro's forecast based on their well property locations (to improve new plant probability weightings and reduce load forecast uncertainty).

The consulting services delivered on key components of the shale gas model: a Montney gas production forecast, and specific recommendations for model improvements.

4.0 Residential Forecast

The following sections describe the methodologies and results of our account forecast, our average use per account forecast and the alternative forecasts of accounts and use per account for the residential sector. At the end of this section, the Residential Load Forecast is presented in table format for first three years of the forecast covering fiscal 2019 and the test period of the F20-F21 RRA.

4.1 RESIDENTIAL SECTOR DESCRIPTION

At the end of fiscal 2018, there were 1.8 million residential accounts served by BC Hydro and electricity sales were 18,148 GWh. This represents about 35 per cent of BC Hydro's total firm sales on a billed basis. Residential customers use electricity for a variety of what we call "end-uses." These include space heating, cooling, lighting, water heating, cooking, refrigeration, and other plug-in loads which include computer equipment and home entertainment systems. Since space heating and cooling loads are dependent on the outside temperature, residential sales can be affected by temperature. As such, our forecasting process, like most utilities, develops a residential sales forecast based on a historical rolling average of temperatures over the past 10 years, or also referred to as a "temperature normalized basis." More information on temperature normalization is available Appendix E of this report.

BC Hydro has four main service regions. In fiscal 2018 electricity use across these regions as a percentage of total residential sales was:

- Lower Mainland 53 per cent,
- Vancouver Island 25 per cent,
- South Interior 13 per cent, and
- North Region eight per cent.

The North Region includes customers connected to our integrated grid and those in our non-integrated areas.

Historical trends in our residential sector include:

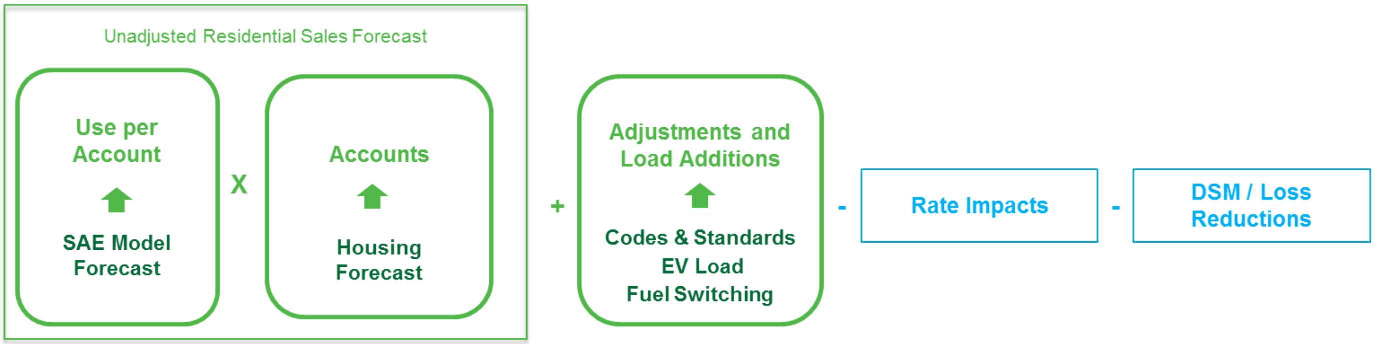
- strong historical growth in accounts which have increased on a year-over-year average of about 23,000 over the past five years ending fiscal 2018,
- a movement to denser multiple housing, and
- a decline in the average use per account.

In fact, over the past five fiscal years ending fiscal 2018, the average residential use per account (annual billed sales divided by the average number of accounts) has declined on both an actual basis and on a temperature normalized basis by 0.9 per cent and 1.1 per cent respectively.

4.2 RESIDENTIAL UNADJUSTED FORECAST MODEL METHODS & COMPARISONS

Figure 5.2.1 below shows our forecasting process and the build-up of the Residential Load Forecast.

Figure 4-1 Residential Forecast Build-up



The equation used to develop the unadjusted[18] residential sales forecast, represented in the first part of the figure, is:

Equation 4.1

$$Unadjusted\ Residential\ Sales\ Forecast = Number\ of\ Residential\ Accounts\ \times\ Intensity\ (average\ use\ per\ account)$$

This equation is applied to develop residential model projections of sales for each of our four service regions. The total residential model projection of sales for our service area is the sum of the regional model projections.

The model projection of average use per account comes from four SAE models (i.e., one model per each major region). The SAE models are calibrated using the past 10 years ending fiscal 2018. The models' inputs include monthly billed data on the average use per account and other load drivers that are specific to the residential sector. The residential account forecast is based housing projections that come from Conference Board of Canada's June 2018 Economic Forecast.

The sum total of model projections, the adjustments, the load additions, and the reductions for rate impacts makes up the residential forecast after rate impacts. The final step in the residential forecasting process includes load reductions for incremental savings from the DSM plan and load reductions for the residential portion of loss reductions. This last step results in the residential load forecast after DSM and loss reductions.

The next two sections discuss the SAE methodology which determines the average use per account and our method of forecasting residential accounts. The alternative method of developing an account and use per account forecast is also described along with the alternative forecast results.

4.2.1 Residential accounts forecast methods and comparisons

4.2.1.1 Comparison of May 2016 to October 2018 residential account forecast method

Our approach to residential accounts forecast for the October 2018 Load Forecast has changed from the methodology used in the May 2016 Load Forecast. The changes were intended to improve the performance of the accounts forecast itself in support of the residential sales forecast.

Table 4-1 below compares the current methodology to the one used in the May 2016 Load Forecast. The main difference between the two approaches is that that growth in accounts in the current method is based on a historical average ratio of growth in accounts to housing growth as opposed to a 1:1 relationship between account growth and housing growth. Appendix E of this report contains a

[18] The terms unadjusted sales forecast and model projections are used interchangeably in this report. Unadjusted sales forecast, within the context of the residential sector, is the product of the average use per account (SAE model projection) and accounts. Unadjusted sales forecast for the commercial sector refers the forecast of sales from the commercial SAE models. Unadjusted sales forecast, within the context of the light industrial sector includes model projections and customer forecasts.

detailed comparison of forecasts under the new and previous method. That analysis indicates that a forecast using our new method is more accurate to a forecast done with previous method.

Table 4-1 Comparison of Residential Current to Previous Account Forecast Methods

Forecast Element	May 2016 Load Forecast Method	October 2018 Load Forecast Method
Internal Inputs based on BC Hydro billing data)	The total number of accounts for single family dwellings / duplex and total number of accounts for all multiple housing types (i.e., row, apartment mobiles) for 15 sub-areas that make up our four major regions.	Same
External Inputs	History and projections of net housing starts (i.e., housing starts less demolitions) for two housing types for 15 sub-areas from Robert Fairholm Economic Consultant, March 2015.	Projection of net housing stock[1] (i.e., growth in housing stock excluding demolition of homes) for the 2 housing types for 15 sub-areas. History of forecast of housing types comes from the Conference Board of Canada, June 2018 Economic Forecast.
Accounts Forecast Method	For Year 1 of the forecast: Number of accounts = base year accounts + net housing starts For Year 2 of the forecast and beyond: Number of accounts = previous year accounts forecast + net housing starts. This is developed for each of the 2 housing types within each of the 15 areas.	For Year 1 of the forecast: Number of accounts for each housing types for the 15 sub-areas is based on a review the current trend in account growth over initial months of fiscal 2019[2] For Year 2 of the forecast and beyond: Number of accounts = previous year forecast of accounts + ratio[3] × net housing stock projection. This is developed for the 2 housing types within each of the 15 sub-areas
Regional Residential Forecast	The forecast for the two housing types for each of the 15 sub-areas is aggregated to develop a total accounts forecast for each of the four service regions.	Same

Table notes:

1. Conference Board of Canada's methodology on developing housing projections for each of the 15 sub-areas by housing type is based on a forecast of net housing stock and gross housing starts. Robert Fairholm Economic Consultant's forecast of housing, which informed the May 2016 Load Forecast of accounts, was based on net housing starts. Both methods account for the impact of demolitions and rebuilds except these impacts are reflected in the net housing stock variable and housing starts variable from the respective economic forecasts.
2. Rather than using the forecast of growth in net housing stock to develop the growth in accounts for the first year of the forecast (i.e., fiscal 2019), the forecast of accounts for that year was based on our analysis of the account growth from our billing statistics from March 2018 to August 2018. Account data from September 2018 was not available in time to inform the account projection of fiscal 2019.
3. The term "ratio" mentioned above is a historical average ratio of account growth to growth in net housing stock for two housing types housing for each of the 15 sub-areas. For each housing type within each of the 15 sub-areas we did a detailed review of the historical ratio of account growth to net housing stock growth to determine an average ratio to be used in the forecast.

4.2.1.2 Comparison of BC Hydro to FortisBC Electric residential account forecast method

In response to comments we received from the BCUC on our May 2016 Load Forecast as stated in Section 3.1, where the, "Panel notes that other utilities such as Pacific Northern Gas, FortisBC [natural gas] and FortisBC [electricity] use a different load forecast methodology for their short term" forecasts, we have developed an alternative forecast based on FortisBC Electric short-term method and compared it against our methodology.

The FortisBC Electric short-term method of developing a residential account forecast is based on a regression of the year-end customer accounts regressed against historical population in the FortisBC Electric service area. A forecast of accounts is developed with the results of the regression and a forecast of population for the FortisBC Electric service area. The history and forecast of population for the FortisBC Electric service area is provided by BC Stats, the provincial government's statistical agency.

To develop an alternative forecast of accounts using FortisBC Electric's method we estimated a regression model of the historical year-end total number of BC Hydro residential accounts and historical population for our BC Hydro service area. We developed a forecast of accounts using the results (i.e., the coefficients) of the regression model and the forecast of population for our service area as per projections from Conference Board of Canada from June 2018. The alternative accounts projection is shown in the last column in Table 4-4 contained in section 4.2.2.2. The statistics and the results of the regression model used to develop the alternative accounts forecast are shown in the table below. The estimate period used in this linear regression model was from fiscal 2014 to fiscal 2018, which is consistent to the number of years that FortisBC Electric uses to estimate their regression model. The regression results indicated that there is a good fit to the historical data (high R-square value) and the coefficients of the regression model are statistically significant (p-values less than 5 per cent).[19]

Table 4-2 Regression Model of Accounts & Population used for Alternative Accounts Forecast

SUMMARY OUTPUT								
Regression Statistics								
Multiple R	0.999							
R Square	0.998							
Adjusted R Square	0.997							
Standard Error	1,893							
Observations	5							
ANOVA								
	df	*SS*	*MS*	*F*	*Significance F*			
Regression	1	5,680,815,259	5,680,815,259	1,585	0.0%			
Residual	3	10,748,971	3,582,990					
Total	4	5,691,564,230						
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	(270,049.71)	50,831.71	(5.3)	1.30%	(431,819)	(108,281)	(431,819)	(108,281)
Population	0.47	0.01	39.8	0.00%	0.43	0.51	0.43	0.51
Durbin-Watson Statistic	2.07							

In contrasting our methodology against this alternative forecast based on FortisBC Electric's approach, two points come to the fore.

First, our accounts forecast is based on the methodology described in Table 4-1 above where the primary driver of our account growth is the forecast of net housing growth provided by the Conference Board of Canada. Given this, our account forecast is a detailed sub-area approach that considers many factors beyond the underlying population and demographic trends across our service area. These factors include items such as interest rates, government policies aimed to cool market as well as housing construction targets aimed for lower incomes.

[19] Descriptions of regression model statistics such as R-squared and p-values are provided in Appendix D

Second, in addition to modelling the underlying demographic demand for housing, the Conference Board of Canada's June 2018 housing forecast also considers the impact of interest rates and government policies such as the provincial government's housing plan and how these factors may impact housing demand. The Conference Board of Canada's modelling of housing growth also considers the impact of large capital investments projects which have secondary impacts on residential housing demands within specific parts of our service area. While we have not reviewed the BC Stats report produced for FortisBC Electric, our understanding is that the population forecast as developed by BC Stats is largely based on demographics factors.

4.2.2 Residential account forecast results and comparison

4.2.2.1 October 2018 residential account forecast results

Table 4-3 outlines the October 2018 Load Forecast's expectations for residential customer accounts out to fiscal 2024.

Table 4-3 October 2018 Residential Accounts Forecast

Fiscal year	Accounts forecast
Actuals	
F2013	1,688,994
F2014	1,709,009
F2015	1,727,945
F2016	1,751,296
F2017	1,776,503
F2018	1,803,752
Forecast	
F2019	1,831,954[1]
F2020	1,861,572
F2021	1,885,943
F2022	1,907,221
F2023	1,927,188
F2024	1,946,489
5 Yr. Actual (F13 to F18)	1.3%

5 Yr. Forecast (F18 to F23)	1.3%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

The account forecast shows an average annual growth of about 24,680 accounts over each of the next five years ending fiscal 2023. This is higher than the historical five year average growth rate which was about 22,952 accounts per year.

The forecast of accounts for fiscal 2019 was based on current year billing data and our assessment of that data as to how accounts would grow over fiscal 2019. Account growth over the first five months of fiscal 2019 was higher than account growth over the previous year after five months. As such, for fiscal 2019 we anticipated continued strong growth in accounts between fiscal 2018 and fiscal 2019.

After fiscal 2019, the account growth is developed for 15 sub-areas (aggregated to 4 service regions then aggregated to a BC Hydro total) with the projections of housing growth and ratios of account growth to housing growth by housing type within these areas. The Conference Board of Canada June 2018 projection of growth in net housing stock anticipates growth between fiscal 2019 and fiscal 2020. This reflects the continued trend of construction in housing which we have seen over the past several years. Beyond fiscal 2020, growth in net housing stock is forecasted to generally decline driven by a projection of lower housing starts. This gradual decline reflects the impact of policy measures introduced to cool housing markets as well as the expectation that interest rates would slowly rise which would also reduce the demand for new housing and new residential accounts.

4.2.2.2 Comparison of BC Hydro to FortisBC Electric residential account forecast results

Table 4-4 below shows the October 2018 accounts forecast versus the alternative accounts forecast developed based on the FortisBC Electric short-term method.

Table 4-4 Accounts Forecast: October 2018 vs FortisBC Electric

Fiscal year	October 2018 Accounts Forecast	Alternative Accounts Forecast based on FortisBC Electric short-term method
Actuals		
F2013	1,688,994	
F2014	1,709,009	
F2015	1,727,945	
F2016	1,751,296	
F2017	1,776,503	
F2018	1,803,752	
Forecast		

F2019	1,831,954[1]	1,827,119[1]
F2020	1,861,572	1,851,419
F2021	1,885,943	1,872,801
F2022	1,907,221	1,894,560
F2023	1,927,188	1,916,691
F2024	1,946,489	1,939,188
5 Yr. Actual (F13 to F18)	1.3%	1.3%
5 Yr. Forecast (F18 to F23)	1.3%	1.2%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

The alternative account forecast predicts that accounts will grow by about 23,367 between fiscal 2018 and fiscal 2019. Our projection is for accounts to grow by about 28,202 over the same time period.

At the end of August 2018, residential accounts had grown by about 11,734 accounts since March 2018. This growth is about 1,600 or 16 per cent more than the growth between March 2017 and August 2017. Given the robust growth in accounts over the past few fiscal years and the fact that account growth seemed to be trending strong through the current fiscal year we believed that our forecast for fiscal 2019 would be more accurate compared to the alternative forecast.

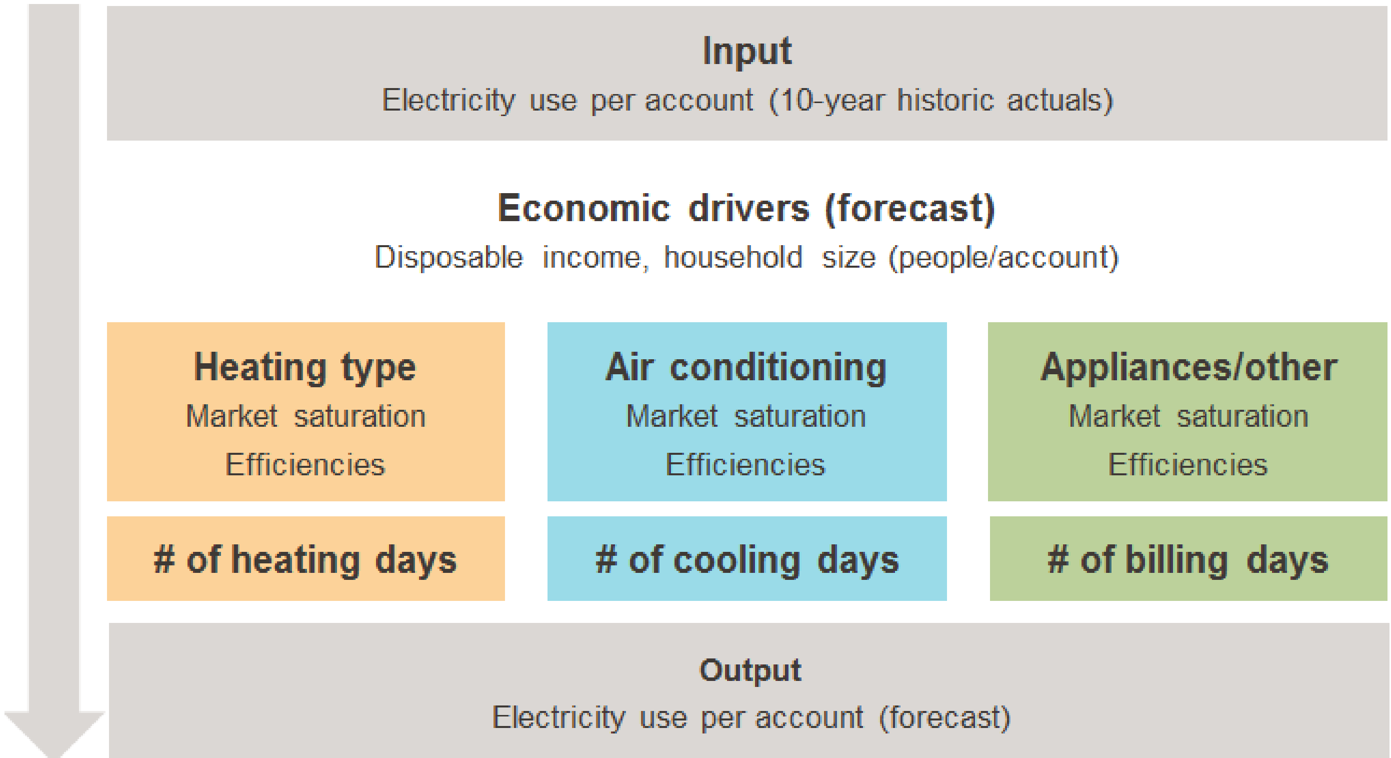
4.2.3 Residential average use per account methods and comparison

4.2.3.1 October 2018 residential average use per account method

BC Hydro uses an industry standard SAE model to estimate the average residential use per account for each of our four main service regions. The SAE approach is used by approximately 60 different utilities and organizations throughout North America. This method has been reviewed in several previous regulatory applications including our F17-F19 RRA.

Figure 4-2 below is a graphical representation of the SAE model while our specific residential SAE models are contained in Appendix D of this report.

Figure 4-2 Residential SAE Model Inputs and Outputs



Our residential SAE models are an end-use regression model which establishes a historical relationship between the average use per account and the historical values for the following variables:

- economic variables including real personal disposable income and household size represented by people per account,
- non-economic variables including the average efficiency of residential end use of electricity, appliance shares (i.e., percentages of customers that have a specific residential electrical appliance), and
- temperature variables represented by heating and cooling degree days.

The forecasts for these variables and the estimated coefficients of our four regional residential SAE regression models determine the model projections of the average use per account over the forecast period for each region.

The SAE model approach has the following main characteristics:

- **A regression element** that develops a historical relationship between heating, cooling, and other major end uses of electricity and the average use per account developed from billing data on residential electricity sales and accounts.
- **An end-use efficiency element** which reflects: (i) future average efficiency projections of residential end uses of electricity for the Pacific region, as developed in 2018 from the U.S. EIA; and (ii) regional BC Hydro data on appliance shares for various end-uses of electricity such as lighting and refrigeration. Regional data on saturation rates come from our historical residential customer end use survey (REUS) while forecasts come from the EIA[20].

  The following examples are provided to illustrate how the model incorporates REUS and EIA elements:

[20] To develop our October 2018 Load Forecast we used the data on from the past 10 residential end use survey including the last survey results complied in 2017.

- Refrigerators: Our latest REUS data indicates that about 99 per cent of our Lower Mainland accounts have a refrigerator with an average efficiency of 582 kWh/year based on data from the EIA. Over the forecast period, market share for refrigerators (99 per cent) is projected to remain unchanged and the EIA data forecasts average refrigerator efficiency to increase to 515 kWh per year.
- Dishwashers: Our REUS data indicates about 78 per cent of our Lower Mainland accounts have a dishwasher and this market share percentage is expected to increase to 83 per cent by the end of the forecast period. From the EIA data, the average efficiency rating is expected to increase from 0.84 (Btu per hour per watt) to 0.91(Btu per hour per watt).

- **An economic element** that reflects future projections of economic variables such as real disposable income and household size represented by people per account. The model also contains elasticities which are estimates of the percentage increase in use per account for a one percentage increase in economic variables. The economic forecasts and elasticities are regional specific for each model. The economic forecasts are based on Conference Board of Canada June 2018 projections.
- **A temperature element** which is measured in heating and cooling degree days. The model is estimated with actual heating and cooling degree days and the forecast is based on a normal temperature which is defined as a ten year rolling average of monthly heating and cooling degree days that are region specific. Using a ten year rolling average will better reflect current trends relative to longer term averaging periods.

Appendix C contains the economic elasticities include in our SAE model. Appendix F contains a summary of the two economic drivers included in our SAE models, EIA end-use efficiency data and regional end-use market saturation data.

4.2.3.2 Comparison of BC Hydro to FortisBC electric account forecast method

In contrast, the alternative forecast of average use per account is developed using a simple regression time trend analysis of the last three years of historical temperature normalized average use per account at the BC Hydro service area.[21]

Table 4-5 below shows the regression model of temperature normalized use per account and a historical time trend. This model is the basis for alternative forecast of average use per account as per FortisBC Electric's short-term method.

[21] To develop the alternative forecast of average use per account we used our historical data on temperature normalized use per account rather than developing a separate historical normalized use per account based on the Fortis BC Electric method of temperature normalization. See Section 19.2 of this report which describes our temperature normalization method for the residential use per account and commercial sales.

Table 4-5 Regression Model Trend in Residential Average use per Account used in Alternative Forecast

SUMMARY OUTPUT								
Regression Statistics								
Multiple R	0.994							
R Square	0.989							
Adjusted R Square	0.977							
Standard Error	23.16							
Observations	3							
ANOVA								
	df	*SS*	*MS*	*F*	*Significance F*			
Regression	1	46,399.70	46,399.70	86.52	6.8%			
Residual	1	536.31	536.31					
Total	2	46,936.01						
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	10,500.815	35.375	296.843	0.2%	10,051.3	10,950.3	10,051.3	10,950.3
Trend	(152.315)	16.375	(9.301)	6.8%	(360.38)	55.75	(360.38)	55.75
Durbin-Watson Statistic	3.00							

The Durbin Watson statistic of 3.00 in the table above indicates there could be auto correlation[22] in the estimated error terms which makes it difficult to assess the statistical significance of the individual variables, the forecast's results, and ultimately the statistical robustness of the alternative model. In contrast, our linear regression SAE models of average use per account are statistically robust, have good fits to the historical data, and generally have statistical significant variables with no auto-correlation in the error terms. Appendix D of this report contains the model statistics for each of our residential SAE models.

On the surface, the regression model above indicates a strong goodness of fit (R-squared value) to the historical data. However, the time trend variable - which is the key driver of the forecast - is not statistically significant. That is, its p-value is just above 5 per cent. The auto-correlation, which may be present, could be due to the wrong functional form, missing variables, or the short period for which the regression model is estimated. As such, further investigation into causes of the auto-correlation would be needed. We did not undertake any further analysis as this would take additional effort to determine the underlying cause of the auto-correlation, if present. In addition, we wanted to establish the regression results for the alternative forecasts to be as close as possible to the FortisBC Electric method.

The major differences in the approaches include:

- our method considers more than one variable (i.e., time trend) to explain the historical variation in use per account and determine a forecast in the use per account, and
- we use a longer time period to develop a statically sound relationship between the average use per account and multiple drivers of average use per account.

After comparing the model approaches to developing a projection for average use per account projection, we expect that the SAE approach to perform better than the alternative forecast method because:

- it uses several variables to develop the forecast rather than a single trend,

[22] A Durbin Watson of 2 would indicate no autocorrelation. Auto-correlation means that the error term in the regression model in one period is correlated with error term in a previous period. Regression models do not have auto-correlation are statistically more robust.

- the SAE model is a multi-linear regression approach that is widely accepted through North America as one of the best practices in load forecasting,
- FortisBC Electric method predicts that the average use per account will decline in direct proportion to the number of the years in the forecast period, a modelling assumption we find too drastic for our context,
- our SAE models are performed well against statistical regression evaluation whereas the alternative method was challenged, and
- given the diversity within our regions, we believe our regional forecasting approach is more reliable than developing a single forecast for our entire service area from a linear time trend.

4.2.4 Residential average use per account results and comparison

4.2.4.1 October 2018 residential average use per account results

The Table 4-6 shows is summary of our SAE model projections of the average use per residential account at the total BC Hydro level, which is based on a weighted average of the regional SAE model projections.

Table 4-6 October 2018 Residential Average Use per Accounts Forecast Results

Fiscal year	October 2018 model projections of average use per account BC Hydro service area (kWh/account)
Actual (temperature normalized)	
F2013	10,625
F2014	10,552
F2015	10,459
F2016	10,358
F2017	10,177
F2018	10,053
Forecast	
F2019[1]	9,981[1]
F2020	9,958
F2021	9,977
F2022	9,990
F2023	10,003

F2024	10,010
5 Yr. Actual (F13 to F18)	-1.1%
5 Yr. Forecast (F18 to F23)	-0.1%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

The results indicate that our average use per account is expected to decline over the forecast period which follows the trend in recent history. These results reflect a number of factors that have put downward pressure on the growth in the average use per account over the forecast period. These factors include:

- a 10 year estimation period (calibration period) ending fiscal 2018, where the historical average use per account has been declining over several years,
- the average efficiency projections from the EIA which generally indicate an increase in efficiency of residential end uses of electricity, and
- the economic variable projections are expected to grow slower over the forecast period relative to history.

Table 4-7 below shows the five year average historical and forecast in the number of people per account and real disposable income in the BC Hydro service area. With fewer people living in a residence, as per the forecast, this means, all else equal, a lower electricity consumption; similarly slower growth in disposable income, all else equal, would tend result in lower electricity consumption.

Table 4-7 Residential Economic Drivers History vs. Forecast

Residential Economic Drivers	Historical Average[3] Growth (F2013 to F2018)	Forecast Average[3] Growth (F2018 to F2023)
People per account[1]	-0.2%	-0.3%
Real disposable income[2]	4.1%	2.4%

Table notes:

1. People per account is based on the ratio of population within our service area to the total number of residential accounts. Population history and forecast come from the Conference Board of Canada’s June 2018 economic forecast, and accounts history and forecasts come from BC Hydro.
2. History and forecast of real disposable income comes from the Conference Board of Canada’s June 2018 economic forecast.
3. Averages for disposable income are computed as an average of the year over year annual growth over five years. The percentages for people per account are computed on a compound growth basis over five years.

4.2.4.2 Comparison of BC Hydro to FortisBC Electric residential use per account results

Table 4-8 shows a comparison of our average use per account alongside that of the alternative model projection for the BC Hydro service area.

Table 4-8 Residential Average Use per Accounts SAE Model vs Alternative Model Projections

Fiscal year	October 2018 model projections of average use per account BC Hydro total service area (kWh/account)	Alternative model projections based on FortisBC Electric short-term method (kWh/account)
Actual (temperature normalized)		
F2013	10,625	10,625
F2014	10,552	10,552
F2015	10,459	10,459
F2016	10,358	10,358
F2017	10,177	10,177
F2018	10,053	10,053
Forecast (temperature normalized)		
F2019[1]	9,981	9,892
F2020	9,958	9,739
F2021	9,977	9,587
F2022	9,990	9,435
F2023	10,003	9,282
F2024	10,010	9,130
5 Yr. Actual (F13 to F18)	-1.1%	-1.1%
5 Yr. Forecast (F18 to F23)	-0.1%	-1.6%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

The alternative model projection shows a forecast of declining use per account that is much higher relative to historical trends. This is due to the fact that forecast is primarily driven by the number of years in the forecast.

In summary, both approaches resulted in declining forecasts of the average use per account which is consistent with recent historical trends. The alternative forecast resulted in a faster decline of average use per account over the forecast period relative to history compared to our model projections.

4.3 RESIDENTIAL SALES FORECASTS

4.3.1 Residential sales forecast methods and comparison

Our Residential Load Forecast is an aggregation of model projections, adjustments for overlap in codes and standards, load additions for EVs and fuel switching, and reductions for rate impacts, DSM and loss reduction savings.

In comparison, the alternative Residential Load Forecast is also an aggregation of all of these forecast elements except for adjustments for codes and standards overlap. The alternative average use per account forecast does not explicitly reflect, unlike our method, that the decline in the average use per account could be from codes and standards which are reflected in our model projections and our DSM plan.

4.3.2 Residential sales forecast results and comparison

4.3.2.1 October 2018 residential sales forecast results

Table 4-9 contains our residential sales forecast after rate impacts. This forecast is an aggregation of model projections, load additions for EVs and fuel switching, and reductions for rate impacts.

Table 4-9 October 2018 Residential Sales History and Forecasts After Rate Impacts

Fiscal year	October 2018 Forecast after Rate Impacts (GWh)
Actual (temperature normalized)	
F2013	17,852
F2014	17,928
F2015	17,973
F2016	18,019
F2017	17,952
F2018	17,997
Forecast	

F2019[1]	18,361[1]
F2020	18,679
F2021	19,007
F2022	19,303
F2023	19,605
F2024	19,912
5 Yr. Actual (F13 to F18)	0.2%
5 Yr. Forecast (F18 to F23)	1.7%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

The forecast above after rate impacts shows that residential sales are expected to grow faster than historical trend. This reflects the increase in accounts, estimates of overlap in codes and standards and EV load. The SAE model projection of average use per account is essentially flat as such not a factor of growth.

4.3.2.2 Comparison of BC Hydro to FortisBC Electric residential sales forecast results

This section presents our results of comparing BC Hydro's forecast methodology with an alternative methodology using FortisBC Electric's short term forecast method.

Table 4-10 shows a comparison of our residential sales forecast after rate impacts and the alternative residential sales forecast after rate impacts. Both forecasts include EVs, fuel switching and rate impacts. Our October 2018 residential sales forecast includes adjustments for overlap in codes and standards, while the other alternative does not include these adjustments. The alternative does not include overlap adjustments because the foundation (i.e., starting point) for the alternative forecast of residential sales is product of a simple time trend of use per account and the alternative accounts projection.

Table 4-10 Residential Sales History and Forecasts After Rate Impacts

Fiscal year	October 2018 Forecast after Rate Impacts (GWh)	Alternative FortisBC Electric Short-term Forecast after Rate Impacts (GWh)
Actual (temperature normalized)		
F2013	17,852	17,852

F2014	17,928	17,928
F2015	17,973	17,973
F2016	18,019	18,019
F2017	17,952	17,952
F2018	17,997	17,997
Forecast		
F2019[1]	18,361	18,116
F2020	18,679	18,092
F2021	19,007	18,033
F2022	19,303	17,977
F2023	19,605	17,947
F2024	19,912	17,940
5 Yr. Actual (F13 to F18)	0.2%	0.2%
5 Yr. Forecast (F18 to F23)	1.7%	-0.1%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

Table 4-11 shows a comparison of our residential sales forecast after DSM and loss reduction savings and the alternative residential sales forecast after DSM and loss reduction savings.

Table 4-11 Residential Sales History and Forecasts After Rate Impacts and After DSM

Fiscal year	October 2018 Residential Load Forecast (GWh)[1]	Alternative FortisBC Electric Short-term Forecast after DSM / Loss Reductions (GWh)[1]
Actual (temperature normalized)		
F2013	17,852	17,852
F2014	17,928	17,928

F2015	17,973	17,973
F2016	18,019	18,019
F2017	17,952	17,952
F2018	17,997	17,997
Forecast		
F2019[2]	18,198	17,953
F2020	18,253	17,667
F2021	18,324	17,351
F2022	18,411	17,085
F2023	18,551	16,893
F2024	18,709	16,737
5 Yr. Actual (F13 to F18)	0.2%	0.2%
5 Yr. Actual Forecast (F18 to F23)	0.6%	-1.3%

Table notes:

1. Loss reductions make up a small component of the load forecast, but are included in the alternative forecast for completeness.
2. Forecast for fiscal 2019 does not include any actuals.

In contrast to the alternative forecast, the October 2018 Residential Load Forecast is higher due to a higher accounts forecast and a higher model projection of the average use per account. In addition to the comparison of performance of the accounts forecast and use per account forecast, here are further reasons we believe our forecast will perform better than the alternative forecast:

- As of September 2018, our Residential Load Forecast for fiscal 2019 was lower by 0.2 per cent relative to actuals over the first six months and higher by 0.6 per cent on a temperature normalized basis. The alternative projection of 17,953 GWh for fiscal 2019 was tracking well below normalized sales by 3.6 per cent over the same time period. As such, we were more confident about our results over this time period, and
- Given the size of the of FortisBC Electric service area it would appear that a top down approach (i.e., one forecast for the service area) is reasonable. Unlike our service area, there is likely no need to further divide the FortisBC Electric service area into sub-regions to develop forecasts for the sub-regions (i.e., bottom up approach). Given the size and diversity of our load, economic growth, and monthly temperatures across our service areas, we believe the residential and commercial forecasts will be accurate from our bottom up approach.

A litmus test for comparing the two forecasts is looking at variance from actuals as measure of forecast performance. To do this, we re-developed residential forecasts for fiscal 2016 to fiscal 2018 using the alternative FortisBC Electric method. Based on our analysis, we found that the residential sales variance, after temperature normalization, using the alternative approach for fiscal 2016 to fiscal 2018 were 0.7 per cent, 2.4 per cent, and 3.9 per cent respectively or an average of 2.4 per cent over all years. These variances are higher compared to the residential variance as per the May 2016 Load Forecast which are 0.1 per cent -0.4 per cent and -0.6 per cent or an average of -0.3 per cent over all years on a temperature normalized basis over the same time period.

4.4 RESIDENTIAL SALES FORECAST BUILD-UP F2019 TO F2021

The billed sales forecast with DSM and loss reductions before accruals is the foundation of the Residential Load Forecast contained in our F20-F21 RRA. The detail on the build-up of the billed sales Residential Load Forecast for fiscal 2019 to fiscal 2021 is presented in the tables below. From the billed sales load forecast we also develop a Residential Load Forecast on an accrued sales basis, which is used to develop our revenue forecast.

Table 4-12 Fiscal 2019 Residential Billed Sales Forecast Build-up

Accounts	Use per account (kWh/ account)	Model projection[1] (GWh)	Codes overlap adjustments (GWh)	EV load additions (GWh)	Fuel switching additions (GWh)	Rate impacts[2] (GWh)	DSM (GWh)	Loss reductions (GWh	Residential Load Forecast[3,4] (GWh)
1,831,954	9,981	18,285	33	48	2	(7)	(158)	(5)	18,198

Table notes:

1. A model projection is average use per account times the number of residential accounts which equals model sales. The model projection above is the sum model projections from all four regions.
2. Rate Impacts is an estimation of load reduction based on formula that include our forecast of real electricity rate increases, a price elasticity assumption of -0.1 and the residential model projections, load adjustments, and load additions.
3. The Residential Load Forecast is an aggregation of model projections, adjustments for codes and standards, load additions less rate impacts, less DSM savings, and loss reductions.
4. The forecast of 18,198 GWh for fiscal 2019 does not include any actual billed sales over the current fiscal year. The forecast of 18,184 GWh (found in the Executive Summary of this report) reflects six months actual billed sales over fiscal 2019 and six months forecast. To develop this estimate the Residential Load Forecast of 18,198 GWh is allocated into 12 months using a rolling five year average shape of monthly billed sales at the BC Hydro level. After the Residential Load Forecast is allocated, the first six months of forecast are replaced with actuals sales.

Table 4-13 Fiscal 2020 and F2021 Residential Billed Sales Forecast Build-up

Fiscal year	Accounts	Use Per account (kWh/ account)	Model projection[1] (GWh)	Codes overlap adjustment (GWh)	EV load addition (GWh)	Fuel switching load addition (GWh)	Rate impacts[2] (GWh)	DSM (GWh)	Loss reductions (GWh	Residential Load Forecast[3] (GWh)
F2020	1,861,572	9,958	18,537	81	65	10	(15)	(418)	(7)	18,253
F2021	1,885,943	9,977	18,815	114	89	14	(26)	(673)	(10)	18,324

Table notes:

1. A model projection is the average use per account times the number of residential accounts. The model projections in the table above are the sum model projections from all four regions.
2. Rate impacts is an estimation of load reduction based on formula that include our real rate increase projection, a price elasticity assumption of -0.1 and the residential model projections, load adjustments and load additions.
3. The Residential Load Forecast is an aggregation developed by model projections, adjustments for codes and standards, load additions less rate impacts less savings for DSM and loss reductions.

4.5 RESIDENTIAL SALES FORECASTS UNCERTAINTIES

Variance in actual residential sales compared to forecast can occur due to many factors, listed below.

4.5.1 Number of accounts

Our current approach depends on our projection of accounts starting in fiscal 2019 and housing growth projections from the Conference Board of Canada, June 2018. In developing the forecast of accounts for fiscal 2019, we used the first five months of account growth from fiscal 2019 to inform our expectations for the remainder of year. While more data over fiscal 2019 would likely enhance the very short term forecast we believe the variance in the forecast of accounts will be less than one per cent for fiscal 2019.

Beyond fiscal 2019, housing trends may differ from what the Conference Board of Canada expects. Factors that could impact housing trends in B.C. over the next several years include:

- provincial housing policy on affordable supply via targeted smaller unit construction,
- federal commitments to affordable housing, and
- government policy aimed at reducing demand and rising house prices through taxes & tightening of mortgage rules.

There is uncertainty as to how consumers will react to all of these measures which are occurring simultaneously.

4.5.2 Use per account

The average use per account forecast is based on our SAE model projections which reflect economic factors and changes in average efficiency and saturation of residential appliances. All of these factors have the potential to contribute to the uncertainty in our load projections. In addition, government policies such as further incentives for EVs may contribute to future variances. Other factors that influence use per account in an upward direction include:

- increases in home sizes,
- increases in air conditioning and other cooling devices, and
- increases in real disposable income.

While some of the countervailing forces working to decrease use per account are:

- increases in appliance efficiencies and consumer uptake of efficient end uses of electricity,
- faster movement towards more multiple dwellings, and
- customers becoming more conscious of electricity use.

4.5.3 Temperature

In the short term, temperature can be highly variable relative to our assumption of a rolling 10 year average trend. Therefore, in any one year, there is a risk that weather and associated temperatures may have a significant impact on residential sales. For example, after the

El Niño event of fiscal 2015, sales to the residential sector declined by close to five per cent between fiscal 2014 and fiscal 2015 mainly due to warmer temperatures. Like most utilities, we develop a forecast based on historical temperature average or on a temperature normalized basis. This is standard practice across most utilities rather than developing an electricity sales forecast based on a prediction of future temperatures and weather conditions.

5.0 Commercial Forecast

5.1 COMMERCIAL SECTOR DESCRIPTION

At the end of fiscal 2018, there were 181,651 commercial accounts and commercial billed sales totalled 14,539 GWh. The commercial sector as of fiscal 2018 was about 28 per cent of BC Hydro's total firm sales.[23]

Within the commercial sector we group customers on the basis of the type of service they receive:

- customers with a demand under 35 kW peak demand within a month which includes operations such as small offices, small retail stores, restaurants, and motels, and
- customers with a demand greater than 35 kW peak demand within a month which includes buildings such as large offices, larger retail stores, hospitals and hotels.

In the last five years, the total increase in commercial sales is about 243 GWh or 1.7 per cent or 179 GWh or 1.3 per cent on a temperature normalized basis. There is not a significant difference in the historical growth trend on an actual and temperature normalized basis because the commercial sector is a very diverse sector.

Given the diversity of businesses and type of operations within the commercial sector, commercial electricity sales are not as sensitive to temperatures as the residential sector. However, some commercial customers such as schools, restaurants, and smaller health care facilities are more sensitive to temperature. Even though the total commercial load is not as temperature sensitive compared to the residential load, we still appropriately factor into our commercial forecasting models historical average temperature variables (i.e., heating and cooling degree days) over the forecast period. As such, the commercial forecasts are prepared on a temperature normalized basis and the actual commercial sales are temperature normalized. For details on the temperature normalization process see Appendix E of this report.

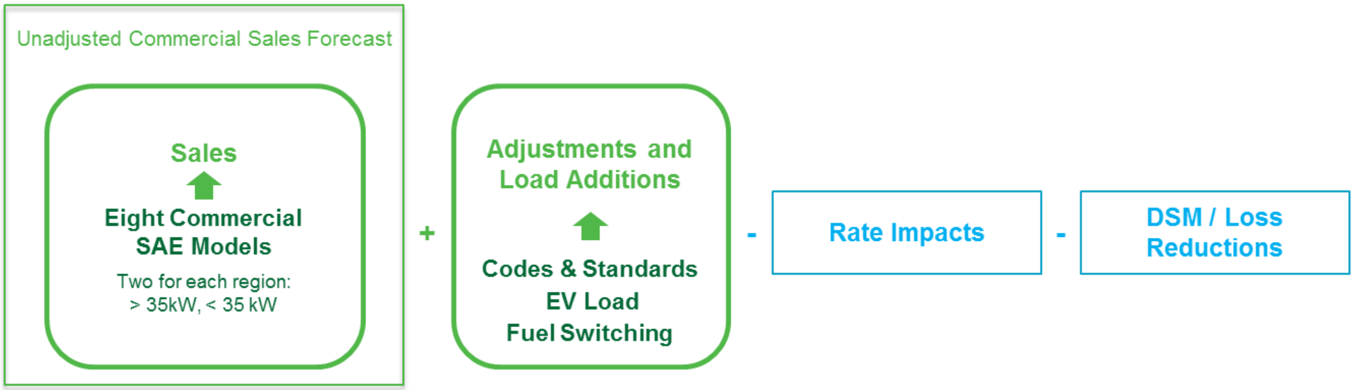
5.2 COMMERCIAL UNADJUSTED FORECAST MODEL METHODS AND COMPARISON

5.2.1 October 2018 commercial forecast methods

Similar to the residential sector, the forecast of commercial sector begins with model projections. Our commercial model projections come from eight SAE models. These eight models correspond to our four major service regions (Lower Mainland, Vancouver Island, South Interior, and North Region) each then divided into the two levels of electrical service mentioned earlier (<35 kW or >35 kW). Most commercial sales are in the Lower Mainland over 35 kW customer group and Vancouver Island over 35 kW customer group. Combined, these two customer groups make up over half of the total commercial sales. Figure 5-1 shows the commercial forecasting process and build-up of the Commercial Load Forecast after DSM and loss reduction savings.

[23] In other BC Hydro annual load forecast documents the commercial sector consisted of electricity sales to commercial customers connected at various distribution levels, two large universities in the Lower Mainland which are connected at the transmission level, street lighting customers, irrigation customers and BC Hydro Own Use. For this report, which supplements our F20-F21 RRA, the commercial sector only consists of the over 35 kW and under 35 kW commercial customers connected to our distribution system.

Figure 5-1 Commercial Load Forecast Build-up



Looking to the left hand portion of Figure 5-1, the starting point in the commercial forecasting process is the commercial SAE model projections. Our commercial SAE model's results and their statistical characteristics are provided in Appendix D of this report.

The general structure of our commercial SAE models is the same as the SAE model diagram shown in the Residential Section (Figure 4-2 of section 4.2.3.1). However, there are with two exceptions. The inputs are different, and model projections for the commercial sector are different, as they are on a sales basis versus average use per account basis.

Each of our eight commercial SAE models is an end use regression model which determines a relationship between historical commercial billed sales and historical values of the two types of variables:

- **economic variables** including employment, retail sales, and commercial GDP, and
- **non-economic variables** including the average efficiency of commercial end uses of electricity and shares of commercial end uses (i.e., the percentages of commercial customers which have a specific commercial end use). The history and forecast of both these variables come from the 2018 dataset developed by the U.S. EIA for the Pacific region. Other non-economic variables include temperature variables represented by heating and cooling degree days.

The forecasts for these variables and the estimated regression coefficients of the eight commercial SAE regression models determine the commercial model projections of electricity sales over the forecast period. Similar to the residential SAE model, our commercial SAE models are estimated over the past 10 fiscal years ending fiscal 2018.

Within our SAE commercial models, one factor determining the projected growth in electricity sales is the anticipated level of future economic activity and its impact. The relationship between the commercial sales and these economic variables are represented as economic elasticities (distinct from price elasticities) in the SAE model. Appendix C of this report describes the updated elasticities that have informed our October 2018 model projections. In addition to reviewing the economic elasticities, we reviewed the relationship between commercial sales and temperature variables. Appendix C of this report also describes the updated temperature variables for each commercial SAE model.

5.2.2 FortisBC Electric alternative commercial forecast method

The FortisBC Electric short-term method involves a model estimated over 15 years. Commercial load is regressed against B.C. real provincial GDP and other binary variables specific to the FortisBC Electric service area.

To prepare the alternative forecast using the FortisBC Electric method we developed several regression models because we had to assess how the FortisBC Electric approach could be applied with our data. As such, we estimated regression models involving our BC Hydro service area, total commercial billed sales and various economic variables such as B.C. provincial real GDP, real GDP at the BC Hydro service area level, employment at the BC Hydro service area level, and real retail sales at the BC Hydro service area level.

All history and forecast of economic data used to estimate the alternative commercial models come from Conference Board of Canada, June 2018 Economic Forecast. Table 5-1 summarizes the statistical results of the alternative regression models we developed.[24]

Table 5-1 Alternative Commercial Forecasting Models

	Model 1	Model 2	Model 3	Model 4	Model 5
Independent Variable	B.C. TOTAL PROVINCIAL REAL GDP	B.C. TOTAL PROVINCIAL REAL GDP	BC Hydro TOTAL REAL GDP	BC Hydro TOTAL EMPLOYMENT	BC Hydro TOTAL REAL RETAIL Sales
Period of Estimation	15 years	10 years	10 years	10 years	10 years
R-squared (Goodness of Fit)[26]	0.65	0.25	0.25	0.34	0.32
Durbin Watson statistic[26]	0.37	2.95	0.25	3.15	3.14
p- value of constant[26]	0.0%	0.0%	0.0%	0.0%	0.0%
p-value of independant variable	0.03%	14.4%	14.5%	7.6%	9.1%
F2018 Temperature Normalized Actual (GWh)	14,513	14,513	14,513	14,513	14,513
F2019 Model Projection (GWh)	14,919	14,513	14,513	14,575	14,556
F2024 Model Projection (GWh)	15,360	14,599	14,600	14,698	14,641

Model 1 in the Table 5-1 comes from a regression model of our total actual commercial sales regressed against real B.C. provincial GDP over the past 15 years ending fiscal 2018[25]. This model was dismissed as an alternative because the forecast from this model after load additions did not track actual sales well over the first six months of fiscal 2019[26]. In addition to this, the Durbin Watson statistic of 0.37 for this model indicated positive auto-correlation in the error terms which could be a result of missing variables or wrong function form.

The other alternative regression models (i.e., models 2 to model 5) in Table 5-1 above involved regressions of our historical temperature normalized commercial sales regressed against the various economic drivers over the past 10 years ending fiscal 2018. All of these regression models have several common statistical features including, having fairly poor statistical fit of the historical data (i.e., low R-squared statistics), the coefficients of independent variables (i.e., the economic variables) were not statistically significant, and most of models indicated no auto-correlation in the error terms.

Model projections for model 2 and model 3 indicated very little growth in sales between fiscal 2018 and fiscal 2019. Unlike model 4 and model 5, these models were dismissed as alternatives because they did not track actual sales data well over the first six months of fiscal 2019. Given the above analysis, we considered model 4 as an alternative regression model because: (i) it had one of the highest R-square values, (ii) it tracked actual sales fairly well over the first 6 months of fiscal 2019,[27] and (iii) the independent variable of employment has historically been a strong variable which we have used in the past to develop commercial SAE model forecasts. Table 5-2 is a full summary of the results of regression model 4.

[24] Definitions of R-squared, Durbin Watson statistic and p-value are described in Appendix D of this document.

[25] We do not have a complete history of commercial temperature normalized sales over the past 15 years with the updated heating and cooling variables included in the October 2018 SAE models.

[26] The assessment of the how the alternative models were tracking to actuals over fiscal 2019 involved developing a load forecast by aggregating the alternative model projections with load additions of EVs and fuel switching and load reductions for rate impacts, DSM savings and savings from loss reductions.

[27] After the first six months of fiscal 2019, the variance of actual sales compared to the alternative forecast (model 4) after DSM and loss reduction savings was 1.66 per cent and the variance in our October 2018 Commercial Load Forecast after DSM and loss reduction savings was 1.10 per cent.

Table 5-2 Regression Model Results of Model 4 (Alternative)

BCH EMPLOYMENT 10 YEARS								
SUMMARY OUTPUT								
Regression Statistics								
Multiple R	0.59							
R Square	0.34							
Adjusted R Square	0.26							
Standard Error	96.63							
Observations	10							
ANOVA								
	df	*SS*	*MS*	*F*	*Significance F*			
Regression	1	38,880	38,880.2	4.2	8%			
Residual	8	74,702	9,337.8					
Total	9	113,583						
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	12,523.99	918.50	13.64	0%	10,405.93	14,642.06	10,405.93	14,642.06
Employment	0.00089	0.00	2.04	7.6%	(0.00)	0.00	(0.00)	0.00
Durbin Watson Statistic		3.15						

5.3 COMMERCIAL UNADJUSTED FORECAST RESULTS & COMPARISON

5.3.1 Commercial unadjusted October 2018 forecast results

Table 5-3 shows the commercial model projection at the BC Hydro service area level.

Table 5-3 October 2018 Commercial SAE Model Projection Results

Fiscal year	October 2018 commercial model projections BC Hydro service area (GWh)
Actual (temperature normalized)	
F2013	14,333
F2014	14,343
F2015	14,460
F2016	14,257
F2017	14,582
F2018	14,513

Forecast	
F2019	14,652[1]
F2020	14,716
F2021	14,729
F2022	14,755
F2023	14,744
F2024	14,763
5 Yr. Actual (F13 to F18)	0.2%
5 Yr. Forecast (F18 to F23)	0.3%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

5.3.2 Commercial unadjusted sales forecast results compared

Table 5-4 contains model projections from the alternative commercial model 4 and our commercial SAE model projections at the BC Hydro service area level. The model projections from both approaches are relatively close to each other for fiscal 2019 and beyond. By fiscal 2024 the alternative model projection is 0.44 per cent lower to the SAE model projections.

Table 5-4 Commercial SAE Model vs Alternative Model Projections

Fiscal year	October 2018 commercial model projections BC Hydro service area (GWh)	Alternative model projections based on FortisBC Electric short-term method (GWh)
Actual (temperature normalized)		
F2013	14,333	14,333
F2014	14,343	14,343
F2015	14,460	14,460
F2016	14,257	14,257
F2017	14,582	14,582

F2018	14,513	14,513
Forecast		
F2019	14,652	14,575[1]
F2020	14,716	14,600
F2021	14,729	14,629
F2022	14,755	14,658
F2023	14,744	14,681
F2024	14,763	14,698
5 Yr. Actual (F13 to F18)	0.2%	0.2%
5 Yr. Forecast (F18 to F23)	0.3%	0.2%

Table notes:

1. Forecast for fiscal 2019 does any actuals.

Our commercial model projections in Table 5-4 are expected to grow slowly and in line with historical sales growth over the forecast period. The variables in our SAE models that contribute to the projection of slow growth include: (i) the updated calibration period reflecting the latest 10 years of historical sales, (ii) the Conference Board of Canada's June 2018, Economic Forecast and (iii) the 2018 EIA projection of average efficiencies for commercial end uses of electricity. The average efficiency forecast for some of the commercial end uses of electricity are projected to increase over the forecast period which puts downward pressure on the model projections of electricity sales. As per the calibration period, both the residential and commercial SAE models are calibrated over the last 10 years of billing data ending fiscal 2018. This calibration period reflects a slower growth of historical sales relative to the previous calibration period used in the May 2016 Load Forecast which was 10 year ending fiscal 2015.

Table 5-5 shows a summary of the historical and forecast of the major commercial economic drivers at the BC Hydro area service level. The forecast of growth in economic drivers, as developed by the Conference Board of Canada Economic Forecast, June 2018 are generally below the historical growth rates which contributes to a slow growth in the SAE models' projections.

Table 5-5 Commercial Economic Drivers History versus Forecast

Commercial Economic Drivers[1]	Historical Growth[2] (F13 to 18)	Forecast Growth[2] (F18 to F23)
Employment	1.7%	1.3%
Real Retail Sales	4.8%	2.4%
Real Commercial GDP	2.9%	2.4%

Table notes:

1. Growth rates are based on data from the Conference Board of Canada, June 2018 Economic Forecast.
2. Averages are computed as an average of the year over year annual growth over five years.

5.4 COMMERCIAL SALES FORECAST RESULTS & COMPARISON

5.4.1 Commercial sales forecast results

Table 5-6 shows the October 2018 commercial sales forecast after rate impacts with history on a temperature normalized basis, and adjacent to that, the October 2018 Commercial Load Forecast after DSM and loss reduction savings. The October 2018 Commercial Load Forecast is an aggregation of all of our SAE model projections, adjustments for code and standards, loads additions, (i.e., EVs and fuel switching) and load reductions (i.e. rate impacts, DSM savings and loss reductions).

Table 5-6 Commercial Sales History and Forecasts After Rate Impacts

Fiscal year	October 2018 Forecast after Rate Impacts (GWh)	October 2018 Commercial Load Forecast (GWh)
Actual		
F2013	14,333	14,333
F2014	14,343	14,343
F2015	14,460	14,460
F2016	14,257	14,257
F2017	14,582	14,582
F2018	14,513	14,513

Forecast		
F2019[1]	14,659	14,568
F2020	14,731	14,484
F2021	14,767	14,353
F2022	14,825	14,244
F2023	14,835	14,113
F2024	14,880	14,034
5 Yr. Actual (F13 to F18)	0.2%	0.2%
5 Yr. Forecast (F18 to F23)	0.4%	-0.6%

Table notes:

1. Forecast for fiscal 2019 does include any actuals.

5.4.2 Commercial sales forecast compared

Just like the residential alternative forecast after rate impacts, the alternative commercial forecast with rate impacts does not include an adjustment for overlap in codes and standards. This is because the alternative model projection depends upon one driver of load which is employment.

Table 5-7 compares our forecast (one after rate impacts, the other after DSM and loss reductions) to their corresponding alternative commercial forecast. Next to the forecasts are the temperature normalized actual sales.

Table 5-7 Commercial Sales History and Forecasts After Rate Impacts and After DSM

Fiscal year	October 2018 Forecast after Rate Impacts (GWh)	Alternative FortisBC Electric short-term after Rate Impacts (GWh)	October 2018 Commercial Load Forecast after Rate Impacts after DSM/Loss Reductions (GWh)[1]	Alternative FortisBC Electric short-term after Rate Impacts and after DSM / Loss Reductions (GWh)[1]
Actual				
F2013	14,333	14,333	14,333	14,333
F2014	14,343	14,343	14,343	14,343

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F2015	14,460	14,460	14,460	14,460
F2016	14,257	14,257	14,257	14,257
F2017	14,582	14,582	14,582	14,582
F2018	14,513	14,513	14,513	14,513
Forecast				
F2019[2]	14,659	14,578	14,568	14,488
F2020	14,731	14,604	14,484	14,358
F2021	14,767	14,642	14,353	14,227
F2022	14,825	14,685	14,244	14,104
F2023	14,835	14,711	14,113	13,990
F2024	14,880	14,735	14,034	13,902
5 Yr. Actual (F13 to F18)	0.2%	0.2%	0.2%	0.2%
5 Yr. Forecast (F18 to F23)	0.4%	0.3%	-0.6%	-0.7%

Table notes:

1. Savings from loss reductions reflected in the Commercial Load Forecast and the alternative forecast attributed to commercial sector is expected to increase from 4 GWh in fiscal 2019 to 13 GWh in fiscal 2024. As such, DSM savings, in particular savings from codes and standards, are expected to contribute to the decline in sales over the forecast period.
2. Forecast for fiscal 2019 does not include any actuals.

We believe that our October 2018 Commercial Load Forecast compared to the alternative forecast, as shown in the Table 5-7 above, is a more reliable forecast because:

- Our commercial SAE model forecasts are developed using variables besides a single driver of the commercial load. We believe the size and complexity of the commercial sector alone demands we include multiple variables, rather depend upon a single driver,
- In addition, the alternative regression models had a poor fit to our historical data. This supports the assertion that other variables besides one economic variable is need to explain how commercial sales have changed over time,
- Given the size of the of FortisBC Electric service area it would appear that a top down approach (i.e., one forecast for the entire area) is reasonable. Therefore, there is no need to further divided up their service area into sub-regions and then add up forecasts for the sub-regions (i.e., bottom up approach). In contrast, given the size and diversity of our load, economic growth, types of

commercial operations, and temperatures across our service area, we believe the commercial forecast is better represented using our bottom up approach, and

- Looking at variance from actuals as measure of forecast performance shows our methodology yielded better when compared to the alternative method applied to our context. To do this, we re-developed commercial forecasts for fiscal 2016 to fiscal 2018 using the alternative FortisBC Electric method. The commercial sales variance on a temperature normalized basis as per the alternative approach[28] for fiscal 2016 to fiscal 2018 were -1.4 per cent, 1.9 per cent, and 1.8 per cent respectively or 0.8 per cent over all years. These variances are higher compared to the variances based on the commercial load forecast as per our May 2016 Load Forecast which are: -2.3 per cent, 0.7 per cent; and 0.3 per cent on a temperature normalized basis from fiscal 2016 to fiscal 2019 respectively or -0.4 per cent on average over all years.

5.5 COMMERCIAL SALES FORECAST BUILD-UP F2019 TO F2021

The commercial sector is most of the light industrial / commercial sector sales. The billed sales forecast of combined total load forecast for light industrial / commercial sector with DSM and loss reductions before accruals is the foundation for light/commercial load forecast in our F20-F21 RRA. As such, the detail on the build-up of the billed sales Commercial Load Forecast for fiscal 2019 to fiscal 2021 is presented in the tables below.

Table 5-8 Fiscal 2019 Commercial Load Forecast Build-up

Model projection[1] (GWh)	Codes overlap adjustment (GWh)	EV load addition (GWh)	Fuel switching load addition (GWh)	Rate impact[2] (GWh)	DSM (GWh)	Loss reductions (GWh)	Commercial Load Forecast[3] (GWh)
14,652	4	8	0	(6)	(87)	(4)	14,568

Table notes:

1. The model projection is the sum total of all commercial SAE model projections.
2. Rate Impacts is an estimation of load reduction based on a formula that includes our real rate increase projection, a price elasticity assumption of -0.1, the commercial model projection, codes overlap adjustment and all commercial load additions.
3. The Commercial Load Forecast is an aggregation of commercial model projections, adjustments for codes and standards, commercial load additions (i.e., EVs and fuel switching) less rate impacts, less DSM and loss reduction savings.

In Table 5-8 above the forecast of 14,568 GWh for fiscal 2019 does not include any actuals over the current fiscal year. After the first six months of the fiscal year this forecast was 77 GWh or 1.1 per cent below actuals. The forecast of 14,646 GWh, as shown in the executive summary, reflects six months actual billed sales over fiscal 2019 and 6 months forecast. To develop this estimate the Commercial Load Forecast of 14,568 GWh is allocated into 12 months using a rolling five year average shape of monthly billed sales at the BC Hydro service area level. After the annual projection is allocated, the first 6 months of forecast are replaced with actuals sales.

[28] To compute these variances, we developed a regression model of historical temperature normalized sales regressed against employment for a 10 year period ending fiscal 2015. Using the regression model and Robert Fairholm Economic Consultant's March 2015 forecast of employment we developed a model projection that was augmented by including EV load additions and reductions for rate impacts and savings for DSM and loss reductions. The elasticity of -0.05 was used for estimate rate impacts. DSM saving and loss reductions savings were the same amounts used in the May 2016 Forecast.

Table 5-9 Fiscal 2020 and F2021 Commercial Billed Sales Forecast Build-up

Fiscal year	Model projection (GWh)[1]	Codes overlap adjustment (GWh)	EV load addition (GWh)	Fuel switching load addition (GWh)	Rate impacts[2] (GWh)	DSM (GWh)	Loss reductions (GWh)	Commercial Load Forecast[3] (GWh)
F2020	14,716	10	12	5	(11)	(241)	(6)	14,848
F2021	14,729	25	16	17	(20)	(407)	(8)	14,352

Table notes:

1. The model projections are the sum total of all commercial SAE model projections.
2. Rate Impacts is an estimation of load reduction based on formula that includes our real rate increase projection, a price elasticity assumption of -0.1, the commercial model projection, codes overlap adjustment and all commercial load additions.
3. Commercial Load Forecast is an aggregation of commercial model projection, adjustments for codes and standards, commercial load additions (i.e., EVs and fuel switching), less rate impacts less loss reductions and DSM savings.

5.6 COMMERCIAL SALES FORECAST UNCERTAINTIES

The Commercial Load Forecast reflects the combination of several forecasts such as model projections, adjustments for code and standards, load additions, and load reductions.

Our unadjusted sales forecasts come from our SAE models which reduces the risk that our commercial forecasting models are not capturing a proper relationship between historical sales and drivers of commercial loads. In addition, our commercial forecasting models have multiple drivers of load as opposed to a single load driver. This reduces forecast risk in that our model projections are from multiple external forecasts rather than one external forecast of one economic variable. We also develop model projections for individual service regions rather than developing a forecast of total commercial load and allocation it to the regions from the top down. This reduces the risk that we don't recognize the diversity within the commercial segments across our service area.

Our forecasting models reflect several factors that impact commercial load including average efficiency assumption, estimates of overlap of codes and standards, economic forecasts, economic elasticities and normalized temperature conditions captured in our heating and cooling variables. As such there is uncertainty in all of these components that make up the commercial forecast. While some of these uncertainties may offset each other, there could be conditions that could lead to a variance in the forecast where the actuals are higher or lower than forecast. Some of these are listed below.

Conditions that could result in lower than forecast commercial sales include:

- a change in the economic conditions where the economy expands less than anticipated in the forecast,
- improved equipment efficiency beyond the trends anticipated in the forecast,
- a high Canadian dollar lowers tourism and retail sales,
- growth in on line shopping and internet business that could result in less activity and future expansion in commercial stores and therefore reduce demand for electricity sales to the commercial retail sector, and

- summers that are colder than normal (reducing air conditioning loads) and winters that are warmer than normal (reducing heating loads).

Conditions that could lead to higher than forecast commercial sales include:

- stronger than projected economic conditions,
- higher demand for commercial office space,
- expansion of the technology sector in B.C.,
- a lower Canadian dollar which encourages tourism and retail sales, and
- summers that are above normal temperatures (increasing air conditioning loads) and winters that are colder than normal (increasing heating loads).

While many of these conditions are factors outside our control addressing them is part of our continuous improvement approach to load forecasting.

6.0 Light Industrial Forecast

6.1 LIGHT INDUSTRIAL SECTOR DESCRIPTION

The light industrial sector consists of approximately 29,000 customers connected at the distribution level. At the end of fiscal 2018, sales to the light industrial sector were 4,364 GWh or 8.3 per cent of our total firm sales. The light industrial sector is subdivided in the following sub-sectors: coal, forestry, oil and gas, and 'other' industrial loads which include various industrial activities such as agriculture and manufacturing.

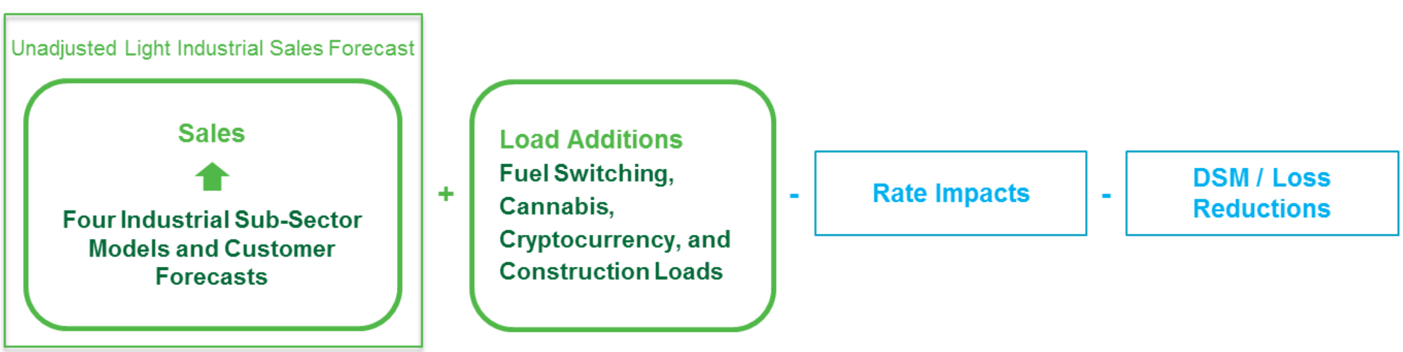
As of October 2018, we have also included the following additional loads to this sector: (i) fuel switching estimates, (ii) incremental cannabis and cryptocurrency loads; and (iii) construction load for LNG plants and other facilities located in northeast B.C. These additional loads are combined with the model projection for the other light industrial loads. While cannabis and cryptocurrency loads are covered in Section 8 of this report, we have included the forecasts for these loads connected at distribution voltages in the tables below to show the total sector load.

Over the past five years, electricity sales across all light industrial customers have grown by 1.8 per cent on average (i.e., five year annual compound growth). This growth has been led by increases in sales in the other light industrial sub-sector and the oil and gas sub-sector. Similar to the large industrial sector, the light industrial sector is not sensitive to temperature variation and is therefore not prepared on a temperature normalized basis.

6.2 LIGHT INDUSTRIAL FORECAST METHODOLOGY

Figure 6-1 shows the process steps to develop the forecast for the light industrial sector. The October 2018 Light Industrial Load Forecast is an aggregation of model projections and customer forecasts from the four main sub-sectors listed above, and load additions for fuel switching, cannabis and cryptocurrency loads, and construction loads. This forecast also includes load reductions for rate impacts, DSM and loss reduction savings. The DSM savings and loss reductions are determined at the total sector level. As such, there are no specific DSM savings and loss reductions for the loads that make up the four main sub-sectors or any of the load additions.

Figure 6-1 Light Industrial Load Forecasting Steps



Each of the sub-sectors uses their own forecast methodology which is described below. Since the light industrial sector is not developed on an end-use basis there is no need for adjustments due to overlaps in codes and standards. In addition, there is no allocation of EV load to this sector.

Customers within the forestry sub-sector (approximately 1,200 GWh per year or 27 per cent of the light industrial sector) encompass sawmills, panel mills and pellet plants. Mill by mill production projections are developed for this sub-sector by the same experts who develop production forecasts for the large industrial wood products segment. The individual mill production forecasts are aggregated together on a regional basis and then multiplied by intensity factors (i.e. kWh/unit of production) to develop regional model projections. These projections are then aggregated to make up the total forestry sub-sector forecast.

Oil and gas customers (approximately 460 GWh or 11 per cent of the total light industrial sector) are involved in production and processing, transportation (pipelines, pump stations, truck terminals) and support services for the oil and gas industry. This sub-sector's forecast is determined on an account by account basis. Account projections are developed with information from BC Hydro Distribution Area planners and Load Interconnections personnel. Probability assessments are carried out on customer requests from natural gas processing plants and natural gas pipeline customers that make up most of the growth in the current forecast.

There are three coal mining customers (approximately 40 GWh or 1 per cent of the total sector sales). This forecast is developed on an account by account basis using a probability weighted approach.

The forecast projections for other industrial distribution loads (2,700 GWh which is approximately 62 per cent of the total light industrial sales) are based on a forecasting model, results of a regression model, and the forecast of real provincial GDP.

Equation 6.1 is the model used to develop the projections for the other light industrial loads. The parameters of this model are informed by coefficients from a regression model of the log of sales per unit of provincial GDP and a time trend. The statistical characteristics and results of the regression model are provided in Table 6-1. These results provide the coefficients for our forecasting model (equation 6.1). The regression model is statistically robust and has a good fit to the historical data, and therefore viewed as a sound model to develop the forecast.

The model used to projections the other industrial loads is the following expression:

Equation 6.1

$$INDD = \left(e^{\propto+\beta T}\right) \times GDP$$

Where:

- INDD is other industrial distribution sales (excluding sales for the sub-sectors of forestry, oil and gas and coal),
- α and β are the regression coefficients from a log regression model of the log of sales per unit of provincial GDP, and a time trend,
- e is exponential base,
- T is a time trend variable, and
- GDP represents the provincial real GDP forecast.

Table 6-1 Log regression model of the log of sales per unit of provincial GDP and a time trend[1]

Variable and Statistics	Result
Constant	2.544 (p-value of 0.0%)
Independent Trend Variable	-0.013 (p-value of 0.0%)
Adjusted R-Square	0.91
Auto-correlation Range (AR)	1-1.34
Durbin-Watson Statistic	1.36
Auto-correlation test result	No Auto-correlation

Table notes:

1. See Appendix D for definitions of p-value, R-Square, Auto-correction Range and Durbin-Watson Statistics.

6.3 LIGHT INDUSTRIAL LOAD FORECAST RESULTS

Table 6-2 shows the forecast for the light industrial sector after rate impacts as the sum of two forecasts:

- the forecast in column A is the sum of model projections and individual customer forecasts for all the sub-sectors (i.e., coal, forestry, oil and gas, and the other light industrial loads) less rate impacts; and
- the forecast in column B is the forecast of total load additions (i.e., incremental cannabis and cryptocurrency loads, fuel switching loads, construction loads for LNG operations, and other facilities) less rate impacts.

Table 6-2 Light Industrial Sales History and Forecasts After Rate Impacts

Fiscal year	A October 2018 model projections / customer forecasts of light industrial sub-sectors after rate impacts (GWh)	B October 2018 total load additions after rate impacts (GWh)[1]	A+B October 2018 light industrials sales after rate impacts (GWh)
Actual			
F2013	3,994		3,994
F2014	4,164		4,164
F2015	4,227		4,227
F2016	4,148		4,148
F2017	4,275		4,275
F2018	4,364		4,364
Forecast			
F2019[2]	4,363	46	4,409
F2020	4,424	113	4,537
F2021	4,437	327	4,764
F2022	4,468	329	4,796
F2023	4,484	346	4,831
F2024	4,518	336	4,855
5 Yr. Actual (F13 to F18)	1.8%		1.8%
5 Yr. Forecast (F18 to F23)	0.5%		2.1%

Table notes:

1. As of fiscal 2018 there were no light industrial customers classified as cannabis and cryptocurrency loads. As such, historical and forecast compound growth rates are not shown. In addition, actual loads for construction were relatively small.
2. Forecast for fiscal 2019 does not include any actuals.

Column A shows the total of the model projections and customer forecasts that make up the four main light industrial sub-sectors less rate impacts. Most of the 155 GWh of growth from fiscal 2019 to fiscal 2024 is attributed to the other light industrial sub-sector and the oil and gas sub-sector. The increase in the other sub-sector is about 81 GWh or 52 per cent of the total growth. This increase is based on the projection of GDP and the regression results in Table 6-1.

Column B shows the total of additional loads from fuel switching, cannabis and cryptocurrency, and construction loads less rate impacts. Most of the increase in the forecast from fiscal 2019 to fiscal 2024 is attributed to incremental sales to cannabis and cryptocurrency loads. In fiscal 2019, the forecast sales to cannabis and cryptocurrency customers are approximately 42 GWh which is expected to increase to about 246 GWh by fiscal 2024. The methodology and further details on the forecasts for the cannabis and cryptocurrency loads are described in Section 8 of this report.

Table 6-3 shows the Light Industrial sales history and forecast after DSM and load reductions.

Table 6-3 Light Industrial Sales History and Forecasts After Rate Impacts and After DSM

Fiscal year	October 2018 Light Industrial Load Forecast (GWh)
Actual	
F2013	3,994
F2014	4,164
F2015	4,227
F2016	4,148
F2017	4,275
F2018	4,364
Forecast	
F2019[1]	4,390
F2020	4,487
F2021	4,683
F2022	4,688
F2023	4,697
F2024	4,697
5 Yr. Actual (F13 to F18)	1.8%

5 Yr. Forecast (F18 to F23)	1.5%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

After accounting for DSM and loss reductions, the total light industrial load growth from fiscal 2019 to fiscal 2024 is about 300 GWh. Most of the growth comes from incremental growth in cannabis and cryptocurrency loads. The forecasted growth for the cannabis and cryptocurrency customers represent customer requested loads that are considered highly probable based on their advanced stage of progress in BC Hydro's interconnection process. In addition, the vast majority of the growth in these emerging sectors comes from new cannabis operations where some of this load includes customers that were already connected to our system but have modified existing operations to become cannabis suppliers in fiscal 2019.

6.4 LIGHT INDUSTRIAL LOAD FORECAST BUILD-UP F2019 TO F2021

The build-up of the Light Industrial Load Forecast for fiscal 2019 and fiscal 2020 to fiscal 2021 is presented in Table 6-4 and Table 6-5, respectively.

Table 6-4 Fiscal 2019 Light Industrial Load Forecast Build-up

Light industrial model projections / customer forecast (GWh[1])	Cannabis/crypto currency load additions (GWh)	Construction load additions (GWh[2])	Fuel switching load additions (GWh)	Rate impacts[3] (GWh)	DSM (GWh)	Loss reductions (GWh)	Light Industrial Load Forecast[4] (GWh)
4,365	42	3	0	(2)	(17)	(1)	4,390

Table notes:

1. The light industrial forecast for the four main sub-sectors.
2. Construction loads included are for future LNG terminals and other facilities.
3. Rate Impacts is an estimation of load reductions based on a formula that includes our real rate increase projection, a price elasticity assumption of -0.1 and the light industrial forecast, including all load additions .
4. The Light Industrial Load Forecast is an aggregation of light industrial model projection, customer forecasts, and load additions (i.e., cannabis and cryptocurrency loads, construction loads, and fuel switching loads), less rate impacts, loss reductions and DSM savings.

The Load Forecast of 4,390 GWh for fiscal 2019 does not include any actuals over the current fiscal year; this forecast was lower than actuals by 25 GWh or 1.2 per cent after the first six months of fiscal 2019. The forecast of 4,415 GWh as shown in the executive summary reflects six months of actual billed sales and six months forecast. To develop this forecast, the 4,390 GWh is allocated into 12 months using a rolling five year average shape of monthly billed sales at the BC Hydro service area level. After the load forecasts are allocated into monthly load forecasts, the first six months of forecast are replaced with actual sales.

Table 6-5 Light Industrial Load Forecast Build-up Fiscal 2020 and F2021

Light industrial model projections (GWh[1])	Cannabis-crypto currency load addition (GWh)	Construction load addition (GWh[2])	Fuel switching load addition (GWh)	Rate impacts[3] (GWh)	DSM (GWh)	Loss reductions (GWh)	Light Industrial Load Forecast (GWh)
4,427	79	34	0	(4)	(48)	(1)	4,487
4,430	242	85	13	(7)	(79)	(2)	4,683

Table notes:

1. The light industrial model projection is the sum of the projections from all four main sub-sectors.
2. Construction loads included are for future LNG terminals and other facilities such as gas pipelines.
3. Rate Impacts is an estimation of load reduction based on formula that include our real rate increase projection, a price elasticity assumption of -0.1 and the model projections and all load additions including in the light industrial sector.

The Light Industrial Load Forecast is an aggregation of the light industrial model projection, adjustments for codes and standards, light industrial load additions (i.e., cannabis and cryptocurrency loads, construction loads, and fuel switching loads), less rate impacts, loss reductions, and DSM savings.

6.5 LIGHT INDUSTRIAL SALES FORECAST UNCERTAINTIES

The total load growth over the forecast period (i.e. fiscal 2019 to fiscal 2024) for the light industrial sector is about 300 GWh. Most of this growth comes from incremental load requests from cannabis and cryptocurrencies. The remainder comes from construction loads and the forecast for each of the four light industrial sub-sectors. Fuel switching loads are not a significant of load growth.

The forecast represents an aggregation of various customers that have requested electricity service for supporting activities for the construction of gas pipelines, LNG projects that have made a final investment decision, and other projects in northeast B.C. We anticipate that these loads will materialize but they could vary over the short term based on construction schedules and when construction will begin to ramp up.

For the light industrial loads related to the 'other' sub-sector, the regression model we have used to develop the sales projection is statistically robust (no autocorrelation) and has a good fit to the historical data (high R-square value). However, since the forecast largely relies upon the GDP forecast, there is a risk that actual GDP growth may vary from forecast.

In addition, the other light industrial sub-sector is composed of manufacturing loads. These loads may respond differently to other factors such as tariffs, exchange rates, technology changes and commodity prices which could impact sales. This also holds true for the oil and gas light industrial sub-sector.

7.0 Large Industrial Forecast

7.1 LARGE INDUSTRIAL SECTOR DESCRIPTION

The large industrial sector is comprised of about 190 customers that account for about 26 per cent of BC Hydro's total firm sales. The individual customers are organized into four main sub-sectors: mining, forestry, oil and gas (including LNG), and other large industrial customers. While light industrial customers are connected at distribution voltages, large industrial customers are connected at transmission voltages. Most of our large industrial customers are involved in extracting, processing and manufacturing resource based commodities, which are largely exported outside B.C. Export volumes can vary significantly from year to year in response to market forces and consequently, electricity sales to this sector can also vary.

7.2 LARGE INDUSTRIAL FORECAST METHODOLOGY

Sales to the large industrial sector are forecast on an individual customer basis. The process that we use to produce the Large Industrial Sector Load Forecast is shown in Figure 7.1.

Figure 7-1 Large Industrial Load Forecast Process

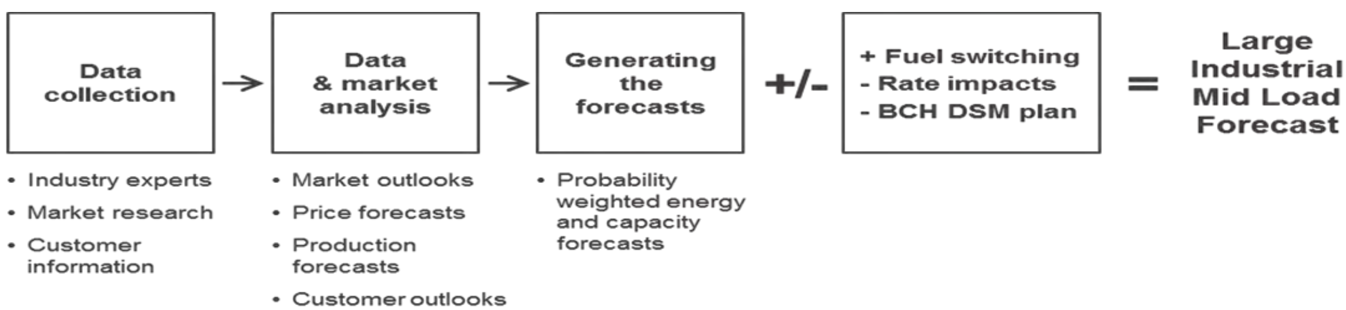


Figure notes:

- Fuel switching amounts are relatively small and are developed on a sub-sector basis.
- Rate impacts are based on an elasticity assumption of -0.1 applied to each sub-sector and real rate increase projections (real dollar bill impacts).
- Forecast of DSM savings are based on our DSM plan.

We develop the Large Industrial Sector Load Forecast using information from several sources. These include:

- **industry experts:** We retain external consultants who develop production and commodity price forecasts and provide both facility and sector-specific market assessments,
- **market research:** We subscribe to services that provide market research and industry analyses in addition to publicly available reports from government agencies, and
- **information from our customers:** Our Key Account Management and Load Interconnections groups who are in contact with our customers gather direct information about those customers' anticipated demand.

Using these sources, we develop probability weightings of expected sales to our current customers. These probability weightings represent a risk assessment of the likelihood of future sales.

For each potential new customer, these same sources of information are used to develop similar probability weightings to forecast if and when new demand may materialize.

Each of these probability weightings represents our professional judgement based on the synthesis of information from our sources as well as factors that are considered when assigning probability weightings, which include:

- how far a customer has passed through our interconnection processes,
- the status of the customer's regulatory/approval permits and project financing,
- BC Hydro's ability to meet the customer's requested in-service date,
- consultant mill, facility and market assessments, where applicable,
- the market outlook for the customer's products,
- the credit and financial viability of the customer,
- the impact of electricity costs on the customer, and
- the likelihood that the customer will take electricity supply from BC Hydro instead of self-supplying their power needs.

Due to commercial sensitivities, individual account assessments are kept confidential. To maintain this confidentiality the large industrial forecast is aggregated by sub-sector.

7.2.1 Additional improvements to large industrial methodology

In addition to modifying the price elasticity assumption described in Section 3, we made improvements to the large industrial load forecast methodology. These improvements specifically address, but also go beyond, issues raised by the BCUC and Load Forecasting Audit. We believe these changes will improve the performance of the forecast.

LNG: We updated our methodology for forecasting sales to LNG customers. In the Site C Final Report, the BCUC observed that "BC Hydro had not made a probabilistic assessment of the likelihood of the LNG load materializing." In this Application, we forecast sales to LNG customers in a manner consistent with other Large Industrial customers: using the probabilistic assessment approach outlined in the Large Industrial Sector Methodology section. For further detail see Section 7.5.2.2.

Probability Weighting: As part of our ongoing internal efforts to improve our load forecast methodology, we changed how we incorporate individual customer probability assessments into the first three years of our large industrial sector load forecast (fiscal 2019 to fiscal 2021). Previously, a customer's load was adjusted by the probability weighting we assigned to it over the forecast period. The probability weightings reflect a number of risk factors, including the likelihood that customers will expand, contract or maintain operations; close operations; or start new operations (e.g., in the case of new customers). A review of our fiscal 2018 variance, as per our May 2016 Load Forecast, showed a significant positive variance (higher actual loads relative to forecast) and negative variance (lower actual loads relative to forecast) for several industrial sub-sectors, notably forestry (positive variances) and oil and gas (negative variances). These variances were determined to be attributed to risk adjustments (i.e., probability weightings) on specific customers that were significantly driven by closure risk considerations (for some existing customers) or start-up likelihood consideration (for new customers). For example, a customer with a 25 per cent probability of closure would have their anticipated load included in a load forecast at 75%. Operationally, the net effect of facility closures or start-ups is that a facility will either be fully operational (i.e., on) or not operating at all (i.e., off). However, the net effect of reflecting those "on/off" risk adjustments in the load forecast results in partial loads. It is the difference between those partial loads reflected in the forecast and actual operations being either "on" or "off" which largely explains the recent industrial sub-sector load forecast variances. To address this BC Hydro has moved to a binary approach for the first three years of the forecast. The binary method results in discrete projection (i.e. in or out) of load and revenues. This approach is applied as follows:

- we continue to undertake probability assessments on an individual customer account basis,

- where the dominant risk factor amongst all others is closure risk, customer loads included in the forecast are reflected at either their full expected load (weighted at 100% probability) or zero load (weighted at 0%) for the period fiscal 2019 to fiscal 2021, depending on whether the closure risk is assessed as being low or high, and
- where the main risk factor is start-up likelihood, only high likelihood projects are included at their full expected load in the period fiscal 2019 to fiscal 2021. For these highly likely projects we also consider project schedule risk as part of the binary assessment. For example, there may be uncertainty on when a project actually comes into service relative to the customer requested in-service date. In these situations we will exercise our professional judgement in deciding whether to reflect the full expected load at a later date than that requested by the customer. If we determine there is a reasonable likelihood the actual in-service date will occur beyond the customer requested in-service date, the full expected load (i.e., weighted at 100%) will be reflected at that later date in the forecast and at zero load (i.e., weighted at 0%) prior to that date.

On an aggregate sector total basis, this binary approach may or may not improve load forecast accuracy over the test period since positive variances in one sub-sector may offset negative variances in another. However, we believe this approach will improve load forecast accuracy for specific segments since it explicitly addresses why the most recent variances occurred. Over the long term, we believe a probabilistic based approach continues to be the best method for developing the large industrial sector forecast on an aggregate basis. Our view is supported by our load forecast audit findings.

In addition to these methodological changes, we retained the services of an oil and gas consulting company to provide additional analysis of shale gas development in B.C., recognizing that the shale gas component of the oil and gas sub-sector is the fastest growing area of our sales. These consultant services are described in section 7.5.2.1.2.

7.3 MINING

As a result of our market outlook and internal information related to service requests from potential new customers, we are expecting minimal growth in the mining sub-sector load between fiscal 2018 and fiscal 2024. The total load in the mining sub-sector in fiscal 2024 is expected to be close to the current level of sales which is 3,900 GWh as of fiscal 2018. A number of uncertainties exist, which are reflected in the high and low forecasts.

7.3.1 Mining sub-sector description

The mining sub-sector accounts for about 29 per cent of sales to the large industrial sector. It is categorized into two segments: metal and metallurgical coal mines. Demand from metal mining makes up 85 per cent of the total sales in the mining sector. Since metal mining represents the vast majority of the mining load for BC Hydro, the drivers of metal mining have the most influence on the total mining load.

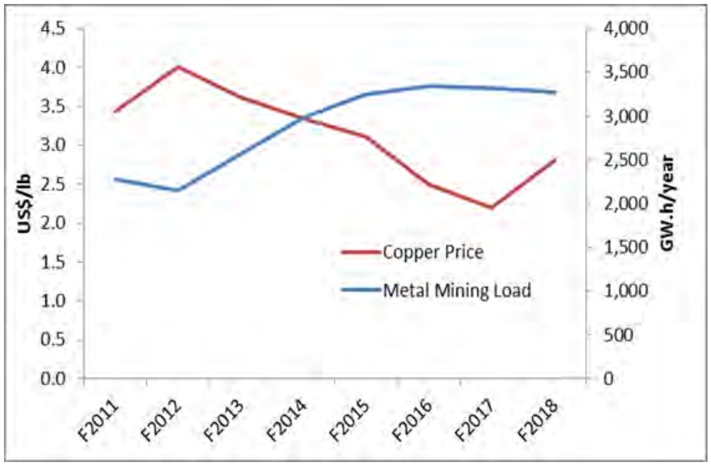
Metal mines typically consume significantly more electricity than coal mines, due to the energy required in the comminution process (crushing and grinding ore to extract the target minerals). Electricity used in metal mining operations typically represents about 10 to 15 per cent of total production costs. The metal mines in B.C. produce predominantly copper with gold, molybdenum, and silver as common secondary products. Two operating mines - Brucejack and New Afton - list gold, as the main product.

Metallurgical coal is an export commodity which is sold worldwide to integrated steel mills for steel-making purposes. Metallurgical coal mines consume less electricity than metal mines, due to the softer sedimentary nature of these deposits. Only crushing is required to break up the rock and energy intensive milling is not required. Electricity used in metallurgical coal operations typically represents about 5 per cent of production costs.

Growth in B.C.'s mining industry is linked to commodity prices, which are driven by economic growth within parts of Asia and the relative global supply/demand balance for copper, metallurgical coal, gold and to a lesser extent molybdenum. China is currently responsible for about 50 per cent of global copper demand. Other factors that impact mining sales and the development of new mines include the availability of financing, regulatory & environmental approvals, and First Nations considerations.

The mining sector is exposed to price volatility and commodity cycles. This is shown in Figure 7-2 below.

Figure 7-2 Metal Mining Load vs. Copper Price



The metals commodity boom between 2009 and 2011 triggered a significant increase in mine development activity. However, this was followed by an economic downturn in 2013-2016, as growth in China slowed down. A recent pick-up in commodities demand as well as supply constraints have caused most metal and coal prices to increase in the last 12 to 18 months, but current global trade tensions are casting a shadow on the price recovery.

Due to long construction periods and additional time to ramp up or ramp down production, electricity sales in the mining sector typically lag commodity prices. Restarts and upgrades at existing operations are generally the fastest response to positive price signals, followed by greenfield additions. Prolonged low price environments may lead to shutdowns, but most closures have also a built-in lag effect as metal miners continue to run the electric intensive mills to process stockpiles months after the shutdown of pit operations.

The recent history of mining load in B.C. is a good example of the lag effect. The commodity price boom in 2009-2011 prompted upgrades at existing operations (e.g., Gibraltar, Endako, Highland Valley) accompanied by brownfield restarts (Copper Mountain, New Afton) and greenfield additions (Mt Milligan, Red Chris and, most recently, Brucejack). This resulted in the metal mining load increasing by approximately 40 per cent between fiscal 2011 – fiscal 2015, despite the commodity market being in a pronounced downturn. The ramp up in mining load after fiscal 2016 was offset by shutdowns at Endako and Huckleberry mines due to low commodity prices and the temporary closure at Mt. Polley due to dam failure. This resulted in a flat profile for mining load between fiscal 2016 and fiscal 2018.

Despite the recovery in copper and metallurgical coal prices over the past year, financing still represents a challenge for miners. Most mining companies scaled back or cancelled exploration activity in recent years and deferred investment decisions. Annual exploration spending in B.C. has decreased from a record $680 million in 2012, to $205 million in 2016 and $246 million in 2017, according to the BC Exploration Survey.[29]

Subsequent to the production of this October 2018 Load Forecast, Imperial Metals announced on January 7, 2019 the suspension of operations at the Mt. Polley mine. In its news release, the company stated the shutdown was due to market conditions, and that the operation will resume, "once the economics of mining at Mt. Polley improve." As a result, we expect reduced sales from Mt. Polley relative to what is included in the mid load forecast from fiscal 2020.

7.3.2 Mining forecast methodology

The mining sector’s sales are forecast on an individual customer account basis, in line with the large industrial sector methodology. There are two independent methods of deriving the forecast of electricity sales for mining customers.

[29] (https://www2.gov.bc.ca/gov/content/industry/mineral-exploration-mining/further-information/statistics/exploration-spending).

The primary method is the product of expected peak demand, load factor, and probability. The load factor is a measure of the utilization rate, or efficiency of electrical energy usage. In case of existing customers, historical consumption information is used as starting point updated with newest information (such as equipment upgrades). The probability weighting, which is informed by the criteria outlined in section 7.2 include factors such as the project's economics, availability of financing, regulatory progress and BC Hydro interconnection status. A mine's economics is analyzed in the context of the global market. The mining forecast includes closure risk for existing customers.

The secondary method uses production, electricity intensity and probability. The production data is informed by the third party subscription and the electricity intensity is derived from our internal sources.

For the current forecast, we rely on the Wood Mackenzie copper mining subscription and Consensus Economics price forecast to support the development of the metal mining forecast. We also use public reports from the Ministry of Energy and Mines, Thompson Reuters, PricewaterhouseCoopers, Deloitte, Genome British Columbia, company public reports and information gather by our Key Account Management and Load Interconnections business units.

In contrast, for the metallurgical coal forecast we rely on Consensus Economics, the Ministry of Energy and Mines, company public reports and internal information.

7.3.3 Mining forecasts results and uncertainties

7.3.3.1 Metal mining segment

7.3.3.1.1 Metal mining segment description

In the long term, electricity sales to metal mines are tied to price expectations for copper and gold and to a lesser extent, molybdenum and silver. The prices of these commodities are influenced by global demand and supply and the state of the global economies. In the short term, month-to-month electricity sales to metal mines are relatively independent of commodity price fluctuations because these mines are fixed-cost operations, running on a continuous basis. Since the most of B.C. metal mining production is exported, mining sales are not overly dependent on domestic economic activity, but rather correlated to the global economy. The top destinations for B.C. mining exports include Japan, the United States, China and South Korea.

7.3.3.1.2 Metal mining segment forecast results

Over the five years ending fiscal 2018, sales to the metal mining segment increased by 730 GWh or 28%. The increase was caused by new metal mining loads in addition to expansions for existing customers. The increase was partially offset by the loss of several customers (Huckleberry, Endako) due to lower commodity prices and the temporary shutdown of Mt. Polley due to the dam event. Table 7-1 shows the history and forecast of metal mining sales before rate impacts.

Table 7-1 Metal Mining Sales History and Forecast Before Rate Impacts

Fiscal year	October 2018 Forecast (GWh)
Actual	
F2013	2,561
F2014	2,978
F2015	3,247

F2016	3,338
F2017	3,321
F2018	3,291
Forecast[2]	
F2019[1]	3,294
F2020	3,427
F2021	3,501
F2022	3,488
F2023	3,457
F2024	3,360
5 Yr. Actual (F13 to F18)	5.1%
5 Yr. Forecast (F18 to F23)	1.0%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.
2. Forecast includes fuel switching estimates.

As result of the market outlook and internal information related to service requests from potential new customers, we are expecting minimal growth in the metal mining load between fiscal 2018 and fiscal 2024. Some equipment upgrades to existing operations are expected to occur between fiscal 2018 and fiscal 2021, which will increase load by approximately 200 GWh. However, any potential (probability weighted) new mining loads between fiscal 2022 and fiscal 2024 are more than offset by expected end of life shutdowns to several existing customers. As a result, the metal mining load in fiscal 2024 remains close to the current level of 3,300 GWh in fiscal 2018.

The copper market outlook[30] which underpins our forecast is summarized as follows:

- although high volatility is inherent with copper prices, the average annual price is expected to continue around $3/lb as global demand grows at a moderate pace driven by construction activity in China and global electrification of various sectors (transportation, manufacturing),
- trade wars are expected to have an effect in short term, but not drive the global economy into a recession,

[30] Copper market outlook is informed by Wood Mackenzie subscription and other sources described in the methodology section.

- new copper supply is coming online but still weighed down by financing constraints. A potential supply gap could emerge around fiscal 2024, and
- absent a geo-political crisis and US dollar fluctuations, gold prices are expected to stay in the range of $1,300/lb in the next few years, which is in line with recent history.

At these price levels BC Hydro expects existing customers to operate normally and there is low incentive to bring new projects into production.

7.3.3.1.3 Metal Mining Uncertainties

The major risks and uncertainties around the metal mine segment over the forecast period include:

- price volatility, boom and bust cycles,
- financial situation for Imperial Metals,
- closures due to accidents,
- rising trend in trade protectionism which impacts global economic growth,
- demand erosion due to substitution effects from other sources (aluminium, steel, composite materials) and rise in scrap recovery,
- higher/lower than anticipated global economic growth mirrored in increased/decreased demand for metals,
- higher/lower than anticipated electrification of transportation and manufacturing,
- outcome of future Environmental Assessment applications from a number of proposed mines, and
- skilled labour shortages for mining companies due to aging workforce and competition with other sectors.

High and low metal mine load forecasts were included into our Monte Carlo uncertainty analysis. These forecasts were developed from high and low commodity price forecasts which are described as follows:

The high forecast was developed base on the following market assumptions:

- higher than anticipated global economic growth and associated increase demand for copper,
- reduced trade tensions,
- increased electrification rates in the transportation and manufacturing sectors,
- increased demand for electronics and electrical products increases,
- increased industrial development increases demand for machinery and equipment. The expansion of the power sector in China and India increases demand for wires and cables,
- as demand continues to grow at higher than expected rate, higher cost copper supply is brought into production, increasing the long-term marginal cost to approximately $4/lb, and
- life expansion and equipment upgrades for certain projects beyond expected assumptions.

The low forecast was developed based on the following market assumptions:

- above average mine supply growth with projects in Panama, Chile, Central Africa and even China hitting the markets in the next few years,
- no mine disruptions weighing on supply,
- demand erosion due to substitution effects from other sources (aluminium, steel, composite materials) and rise in scrap metal recovery, and

- prices drop to $2/lb in the next two years. As mines don't recoup total costs (including cost for sustaining production), higher cost mines exit the market resulting in a small recovery in price over the longer term.

The high, mid and low metal mining forecasts before rate impacts are shown in Table 7-2.

Table 7-2 Metal Mining Mid, High and Low Forecasts Before Rate Impacts

Fiscal year	High Forecast (GWh)	Mid Forecast (GWh)	Low Forecast (GWh)
Actual			
F2018	3,291	3,291	3,291
Forecast			
F2019[1]	3,294	3,294	3,271
F2020	3,427	3,427	3,080
F2021	3,905	3,501	2,344
F2022	4,123	3,488	2,081
F2023	4,553	3,457	2,081
F2024	5,146	3,360	1,839
5 Yr. Forecast (F18 to F23)	6.7%	1.0%	-8.8%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

7.3.3.2 Metallurgical coal segment

7.3.3.2.1 Metallurgical coal segment description

Coal mines account for about 15 per cent of BC Hydro's total mining sector sales. Teck's Elk Valley Coal Partnership in southeast B.C. supplies about one sixth of the world's seaborne metallurgical coal market. Metallurgical coal is also produced in northeastern B.C.

In the long term, coal mining sales are tied to price expectations for metallurgical coal. Export markets for B.C. coal include China, Japan, South Korea, and to a lesser extent India, Europe, South America and the United States. As a result, the state of B.C.'s economy has little effect on coal sales; however, provincial regulatory and policy actions can have a significant impact.

7.3.3.2.2 Metallurgical coal forecast results

Over the past five years ending fiscal 2018, sales to the metallurgical coal segment increased by 48 GWh or 9 per cent. This increase was caused by equipment upgrades at existing customer sites. Table 7-3 shows the history and forecast of metallurgical coal sales before rate impacts.

Table 7-3 Metallurgical Coal Mining Sales History and Forecast Before Rate Impacts

Fiscal year	October 2018 Forecast (GWh)
Actual	
F2013	541
F2014	551
F2015	560
F2016	545
F2017	562
F2018	589
Forecast	
F2019[1]	533
F2020	558
F2021	567
F2022	563
F2023	563
F2024	579
5 Yr. Actual (F13 to F18)	1.7%
5 Yr. Forecast (F18 to F23)	-0.9%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

The metallurgical coal market outlook which underpins our forecast is summarized as follows:

- the price for metallurgical coal has recovered sharply over the last two years after the significant downturn that occurred from 2013 to 2016,
- however, global supply restarts are expected to reduce prices in the next few years to approximately $USD140/tonne, and
- at this level, we expect existing coal operations to continue to operate normally, but there are no new mine additions in the forecast range.

The forecast expects the load impacts from equipment and production upgrades to be offset by the recent shutdown of Teck's Coal Mountain operations.

7.3.3.2.3 Metallurgical coal uncertainties

The major risks and uncertainties around the metallurgical coal segment over the forecast period include:

- global economic outlook: higher/lower than anticipated demand for steel in Asia,
- supply disruptions (or expansions) in Australia. Australia accounts for roughly two-thirds of the global metallurgical coal production; Floods during the rainy season in Australia have caused major supply disruptions in recent years,
- environmental lawsuits with regards to Teck operations,
- rail and terminal capacity constraints in B.C, and
- future regulations and policies that could impact future coal exploration or development.

High and low metallurgical coal mine forecasts were included as inputs into the Monte Carlo uncertainty analysis. These forecasts were developed from high and low commodity price forecasts which are described as follows:

The high forecast was developed based on the following market assumptions:

- higher than expected demand for steel in Asia,
- potential disruptions to Australian coal supply, and
- prices increase to a long-term level $USD175/tonne, which is sufficient to incent new supply additions.

The low forecast was developed based on the following market assumptions:

- lower than expected demand for steel in Asia,
- expansion to Australian coal supply, and
- prices drop to $USD100/tonne below the estimated long term operating cost of 75 per cent of the world's seaborne metallurgical coal production.

The high, mid, and low metallurgical coal forecasts are shown in Table 7-4.

Table 7-4 Metallurgical Coal Mid, High and Low forecasts Before Rate Impacts

Fiscal year	High Forecast (GWh)	Mid Forecast (GWh)	Low Forecast (GWh)
Actual			
F2018	589	589	589

Forecast			
F2019[1]	559	533	533
F2020	584	558	541
F2021	594	567	495
F2022	600	563	501
F2023	790	563	501
F2024	790	579	501
5 Yr. Forecast (F18 to F23)	6.1%	-0.9%	-3.2%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

7.3.3.3 Mining forecast results

Table 7-5 shows the high, mid, and low forecasts for the mining sub-sector. The forecast for this sub-sector mirrors the forecast for metal mining segment since metal mining represents approximately 85 per cent of the mining load.

Table 7-5 Mining Sub-Sector Mid, High, and Low Forecasts Before Rate Impacts

Fiscal year	High Forecast (GWh)	Mid Forecast (GWh)	Low Forecast (GWh)
Actual			
F2018	3,880	3,880	3,880
Forecast			
F2019[1]	3,853	3,827	3,804
F2020	4,012	3,985	3,621
F2021	4,499	4,068	2,839
F2022	4,723	4,051	2,582
F2023	5,343	4,020	2,582
F2024	5,937	3,939	2,340

5 Yr. Forecast (F18 to F23)	6.6%	0.7%	-7.8%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

7.4 FORESTRY

7.4.1 Forestry sub-sector description

The forestry sub-sector's once dominant share of the large industrial sector has steadily declined over time. While still significant, the sub-sector now only accounts for about 50 per cent of sales to the large industrial sector. Forestry is categorized into the following three segments:

- pulp and paper,
- wood products, and
- chemical.

Proportionally, the pulp and paper segment comprises 61 per cent of forestry sales, chemical sales 21 per cent and wood products 18 per cent. Pulp and paper production is evenly split between those two products. Paper production consists primarily of newsprint and newspaper inserts. Our chemical customers produce bleaching agents to whiten the products produced by the pulp and paper industry. They also produce cleaning and water purification agents for oil and gas producers and municipalities. In addition, our wood products customers produce lumber, panel sheets (like plywood and oriented strand board) and pellets for fuel. Products produced by the forestry sub-sector are primarily destined for the U.S., Chinese and B.C. economies. Detailed descriptions are provided within each forestry segment's description.

7.4.2 Forestry segment methodologies, forecast results and uncertainties

The methodologies used by each of the segments within this sub-sector are consistent with the methodology used for the large industrial sector. The forecasts are developed on an account by account basis.

7.4.2.1 Pulp and paper

7.4.2.1.1 Pulp and paper segment description

Sales to the pulp and paper segment represent 61 per cent of all forestry sales and 31 per cent of the total Large Industrial sector sales.

Pulp and paper consists of 19 mills located primarily in the south-western and north-eastern parts of B.C. These mills produce and export a wide variety of products including newsprint, coated and uncoated ground wood paper, bleached and unbleached Kraft, dissolving pulp, thermo-mechanical pulp (TMP), and bleached chemical-thermo-mechanical pulp (BCTMP). Historically, sales to this segment have been declining and we expect this to continue.

7.4.2.1.2 Pulp and paper methodology

While consistent with the large industrial sector forecast methodology, the pulp and paper segment forecast incorporates additional market evaluations and mill assessments. These are developed by third party industry experts. They forecast commodity supply, demand and prices in the markets where B.C.'s pulp, paper and wood products are sold. They also project B.C. regional market conditions for fibre supply (sawmill residuals, whole log chipping, etc.) and fibre demand (for bioenergy, pulp and paper and wood product mills). They consolidate these to produce mill line production forecasts and operational probability assessments to reflect a mill line's closure and start-up risk.

The production forecast and probability assessments are internally reviewed with input from a number of BC Hydro departments, including Key Account Management. Mill line load forecasts are developed by multiplying production forecasts, probability assessments, and mill line electricity intensities. Mill line forecasts are then aggregated to the plant level, which forms the customer load forecast. Customer account forecasts are then aggregated to form the pulp and paper forecast.

A number of pulp and paper mills also sell power to us under Electricity Purchase Agreements (EPAs). For those mills, the conditions of these agreements are taken into account for developing the customer's forecast.

The main drivers for this segment include:

- pulp and paper prices,
- economic growth and associate pulp and paper demand internationally,
- U.S. import duties on B.C. publication paper,
- regulations in China banning paper recycling which lift kraft and BCTMP prices and incent B.C. publication paper producers to convert paper lines to recycling,
- consumer preference for various pulp and paper products,
- B.C. fibre availability,
- global preferences for substitutes over B.C.'s pulp and paper products - particularly new eucalyptus pulp supply from the southern hemisphere,
- folding box demand in China (a major driver for TMP), and
- new market development in China, India and emerging markets for publication papers.

7.4.2.1.3 Pulp and paper forecast results

B.C.'s pulp and paper mills can be further categorized into the customer products they primarily produce:

- TMP and BCTMP,
- Kraft,
- publication paper, and
- tissue & other.

Over the past five years ending fiscal 2018, sales have declined by 1,377 GWh or 25 per cent. Reduced sales occurred across all four product types (arising from mill and mill line closures across the province). The decline is sales within each product type can be seen in Table 7-6 shows historical and forecast pulp and paper sales before rate impacts for each product category.

Table 7-6 Pulp and Paper Segment Sales History and Forecast Before Rate Impacts

Fiscal year	BCTMP (GWh)	Kraft (GWh)	Publication Papers (GWh)	Tissue & Other (GWh)
Actual				

F2013	1,318	1,508	2,642	143
F2014	1,137	1,580	2,685	104
F2015	1,120	1,607	2,434	101
F2016	1,216	1,123	2,290	97
F2017	1,072	906	2,098	97
F2018	1,060	923	2,151	100
Forecast				
F2019[1]	1,029	873	2,082	100
F2020	1,017	873	2,184	99
F2021	1,017	894	1,468	98
F2022	1,017	903	1,080	99
F2023	966	894	1,066	99
F2024	1,145	877	1,009	99
5 Yr. Actual (F13 to F18)	-4.2%	-9.3%	-4.1%	-7.0%
5 Yr. Forecast (F18 to F23)	-1.8%	-0.6%	-13.1%	-0.2%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

Factors contributing to mill closures were aging equipment, declining fibre availability (due to pine beetle infestation), strong competition from Kraft mills in South America, displacement of newspaper by digital media, adoption of power saving projects, and increased use of electronic media by advertisers.

For the period fiscal 2019 to fiscal 2021, sales are forecasted to decline by 606 GWh or 15 per cent. Expected reductions in publication paper and BCTMP production are the main reasons behind this decline.

Over the period of fiscal 2018 to fiscal 2024, sales are projected to decline by 1,105 GWh or 26 per cent. Most of the decline is attributed to higher closure risk assigned to publication paper mills. Electricity sales to Kraft mills are expected to remain stable over the forecast period as Kraft prices and fibre availability are anticipated to remain favourable.

7.4.2.1.4 Pulp and paper uncertainties

The major risks and uncertainties for pulp and paper over the forecast period include:

Upside risks:

- market opportunities for publication paper mills (e.g., converting newsprint lines to waste paper recycling lines),
- BCTMP mill restart due to continued high growth trend in the folding box market in China,
- biofuel production at B.C. Kraft mills due to growing demand for renewable fuels, and
- Kraft mill sustainability due to higher than expected fibre supply in B.C.

Downside risks:

- publication paper mill closures (from publication paper demand shrinkage in the North American market as the public continues to switch from print to electronic media),
- BCTMP mill failure to restart (caused by reduced Chinese market demand for B.C. BCTMP imports and increased reliance on lower cost, lower quality domestic producers),
- Kraft mill closures due to pulp fibre supply shortages caused by wildfires, beetle infestation and sawmill closures, and
- foreign market import duties imposed by the US and/or Chinese governments on B.C. pulp and paper.

High and low pulp and paper load forecasts were developed and included in the high and low forecasts for the forestry sub-sector as inputs into the Monte Carlo uncertainty analysis. Table 7-7 shows the high, mid, and low forecasts before rate impacts.

Table 7-7 Pulp and Paper Segment Mid, High and Low Forecasts Before Rate Impacts

Fiscal year	High Forecast (GWh)	Mid Forecast (GWh)	Low Forecast (GWh)
Actual			
F2018	4,234	4,234	4,234
Forecast			
F2019[1]	4,196	4,083	3,907
F2020	4,611	4,174	3,695
F2021	4,652	3,477	3,078
F2022	4,407	3,099	2,429
F2023	4,344	3,025	2,330
F2024	4,384	3,129	2,352
5 Yr. Forecast (F18 to F23)	0.5%	-6.5%	-11.3%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

The high and low forecasts are not symmetric around the mid forecast. Table 7-7 shows the high forecast is proportionally higher relative to the mid forecast than is the low forecast. The high forecast assumes market conditions evolve such that publication paper customers profitably retool and expand production. For instance, our pulp and paper market consultant has identified new growing markets like waste paper recycling, tissue and paper packaging to displace plastic. These new market opportunities represent potential mill line conversion opportunities for B.C. publication paper mills. Moreover, with waste paper recycling, the Chinese government has banned waste paper imports into the country to reduce water pollution. Consequently, Chinese paper recyclers are no longer able to buy waste paper from North America. As a result, North American paper mills are being converted into waste paper recyclers to meet growing paper demand in China with abundant supplies of low cost waste paper, including in B.C.

7.4.2.2 Wood products

7.4.2.2.1 Wood products segment description

Wood products sales make up 18 per cent of all the forestry sub-sector sales and 9 per cent of Large Industrial sector sales. Wood products consists of large industrial customers who use electricity to produce dimensional and structural lumber, oriented strand board, medium density fiberboard, plywood, fuel pellets, and other specialty wood products. There are 35 such mills, which are primarily located in the North and South Interior regions. B.C. mills are among the lowest cost lumber producers in the world.[31]

Electricity sales to the wood products segment depends on regional B.C. lumber supply, global demand for wood products and the viability of some pulp and paper mills. Recent growth in lumber demand was driven by the growth in U.S. housing starts. However, B.C. lumber supply will be constrained by saw-log scarcity due to the mountain pipe beetle devastation and recent record wildfires in the province. Although the Ministry of Forests, Lands, Natural Resource Operations and Rural Development is undertaking measures to address these, we anticipate reductions in annual allowable cuts will be imposed such that sales to this sector will start declining around fiscal 2023.

7.4.2.2.2 Wood products methodology

Similar to the pulp and paper segment, the process for developing the wood products load forecast is based on mill line production forecasts that are determined from macro and regional market assessments developed by a number of third party industry experts retained by BC Hydro.

Like the pulp and paper forecast, the wood products forecast is produced as a product of mill line production forecast, electricity intensity and probability for each customer operation. The loads for individual mill lines are aggregated to the entire load for the customer and all the customers forecasts are aggregated together to develop the forecast for the wood product segment.

The primary market drivers for wood products are:

- the U.S. market (for housing starts and repair and remodeling),
- the Chinese market (lumber and logs), and
- Japan (hemlock and SPF lumber).

B.C. is the largest Canadian exporter of softwood lumber to the U.S., making up about half of Canada's total lumber exports. Exports to China have been growing and B.C. could soon displace Russia as the dominant lumber supplier to the Chinese market.

[31] There are hundreds of other smaller wood products mills served on distribution service which are included in the forestry sub-sector in the light industrial sector.

7.4.2.2.3 Wood products forecast results

Table 7-8 shows the history and forecast of the wood products segment before rate impacts. For the most part, sales to this segment have declined over the historical period up to fiscal 2017. Between fiscal 2017 and fiscal 2018 there was a significant increase of electricity sales to the wood product segment driven by record high U.S. lumber prices in response to increases in U.S. housing starts.

Table 7-8 Wood Products Segment Sales History and Forecast Before Rate Impacts

Fiscal year	October 2018 Forecast (GWh)
Actual	
F2013	1,164
F2014	1,148
F2015	1,155
F2016	1,208
F2017	1,141
F2018	1,243
Forecast	
F2019[1]	1,223
F2020	1,228
F2021	1,231
F2022	1,231
F2023	1,224
F2024	1,193
5 Yr. Actual (F13 to F18)	1.3%
5 Yr. Forecast (F18 to F23)	-0.3%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

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For the period fiscal 2019 to fiscal 2021, sales are expected to increase by only 8 GWh or 1 per cent. The reasons for this are two offsetting impacts: continued demand from the U.S. housing market, albeit influenced by the U.S.-Canada softwood lumber dispute, and B.C. fibre shortages from mountain pine beetle damage and recent record wildfires.

From fiscal 2018 to fiscal 2024, sales are projected to decline by 50 GWh or 4 per cent. Expectations for this period can best be described as mixed and somewhat uncertain. Electricity sales are projected to slightly increase in the short run with a decline thereafter. U.S. housing starts are expected to continue to rise through the forecast period but the U.S.-Canada softwood lumber dispute and B.C. fibre shortage (from mountain pine beetle and recent record wildfires) will raise mill production costs and put downward pressure on sales to various mills and the sector.

7.4.2.2.4 Wood products uncertainties

The major risks and uncertainties for wood products over the forecast period include:

Upside risks:

- removal of softwood lumber tariffs. The U.S. government has imposed an average 20 per cent tariff on B.C. lumber imports. Removal of the tariff would raise revenues to B.C. producers and stimulate sawmill production,
- higher than expected in U.S. housing start levels. The U.S. is B.C.'s largest export market. Although US housing starts hit 10 year highs in 2018 and have been trending upward, they are still at historically stagnant levels (in the context of US housing starts over the past 50 years), and
- a stronger U.S. dollar.

Downside risks:

- useable timber reductions in B.C. Large wildfires and/or accelerated beetle kill deterioration of affected timber, will reduce harvestable areas, increase harvesting costs and contribute to wood product mill closures,
- lower than expected U.S. housing start levels. The U.S. is B.C.'s largest export market; depressed levels of U.S. housing starts that cause lumber prices to decline and increase wood product mill closure risk,
- U.S. recession. This would cause a prolonged economic downturn would cause housing starts to decline and remain at low levels. This would reduce cause lumber and panel prices to decline; this in turn would increase wood product mill closure risk, and
- reduced demand from China. This could arise from a prolonged economic slowdown in China and/or the Chinese government imposing import duties on Canadian lumber.

High and low forecasts for the wood products segment were developed and rolled up into the high and low bands for the forestry sub-sectors and used in the Monte Carlo uncertainty analysis.

Table 7-9 shows the historical and high, mid, and low forecasts for wood products segment before rate impacts. The high and low forecasts are symmetrical projections around the mid forecast.

Table 7-9 Wood Products Segment Mid, High and Low Forecasts Before Rate Impacts

Fiscal year	High Forecast (GWh)	Mid Forecast (GWh)	Low Forecast (GWh)
Actual			
F2018	1,243	1,243	1,243

Forecast			
F2019[1]	1,247	1,223	1,192
F2020	1,320	1,228	1,045
F2021	1,366	1,231	1,041
F2022	1,366	1,231	1,045
F2023	1,358	1,224	1,035
F2024	1,326	1,193	995
5 Yr. Forecast (F18 to F23)	1.8%	-0.3%	-3.6%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

The high forecast assumes higher than expected demand from U.S. housing starts and lumber exports to China. While this forecast assumes high lumber prices, increased production is assumed to be constrained by increased logging and stumpage costs resulting from deteriorating fibre supply.

The low forecast assumes some mills operate at reduced capacity or are closed. This is assumed to occur as a result of weaker demand from the U.S. and Chinese markets and deteriorating fibre supply. For the U.S. market, housing starts are assumed to only moderately rise and the softwood lumber dispute to remains unresolved.

The low forecast also assumes slower economic growth in China with increased market competition for B.C. wood products from other jurisdictions (Russia, New Zealand, and Europe). Both U.S. and Chinese market assumptions result in lower lumber prices for B.C. producers. In addition, wood harvesting costs are assumed to increase as a result wildfire and mountain pine beetle effects on fibre supply. The net effect of the market and fibre supply conditions is assumed to trigger mill closures or mills to operate at lower production levels.

7.4.2.3 Chemical

7.4.2.3.1 Chemical segment description

The chemical segment represents 21 per cent of Forestry sub-sector sales and 11 per cent of the large industrial sector. Chemical plants produce bleaching agents for the pulp and paper industry, cleaning agents or the oil and gas industry, and water purification products for municipalities. Since chemical companies use electrolysis to produce their products, electricity represents a significant component of their operating costs.

7.4.2.3.2 Chemical methodology

Consistent with the large industrial sector methodology, the chemical segment is forecast on an individual account basis. For this segment, the forecast relies on customer information provided by our Key Account Management group. The chemical forecast methodology is mainly informed via discussions with customers. Key drivers for the chemicals segment are electricity prices, demand for bleaching agents from the pulp and paper industry, and cleaning agents from the oil and gas industry. The industry also has the ability to export its products should B.C.-based demand decline.

7.4.2.3.3 Chemical segment forecast results

From fiscal 2013 to fiscal 2018, chemical sales declined by about 98 GWh or 6 per cent. This decline was primarily due to savings achieved through our DSM programs as well as a plant closure in fiscal 2018. Table 7-10 shows the history and forecast of sales to the segment before rate impacts.

Table 7-10 Chemical Segment Sales History and Forecast Before Rate Impacts

Fiscal year	October 2018 Forecast (GWh)
Actual	
F2013	1,575
F2014	1,580
F2015	1,541
F2016	1,456
F2017	1,409
F2018	1,477
Forecast	
F2019[1]	1,350
F2020	1,349
F2021	1,349
F2022	1,347
F2023	1,347
F2024	1,347
5 Yr. Actual (F13 to F18)	-1.3%
5 Yr. Forecast (F18 to F23)	-1.8%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

From period fiscal 2019 to fiscal 2021, sales are forecast to decline by 1 GWh. Sales beyond fiscal 2021 are expected to remain stable.

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7.4.2.3.4 Chemical Uncertainties

The major risks and uncertainties for the chemical segment include the following:

Upside risks:

- higher than expected bleaching agent demand from global pulp and paper producers experiencing a sustained increase in pulp and paper prices, and
- higher than expected cleaning agent demand from oil and gas producers.

Downside risks:

- global slowdown in demand from global pulp and paper producers,
- domestic pulp and paper closures, and
- rationalization of a chemical company operating in B.C. to close and resupply from a plant outside the province.

High and low forecasts for the chemical segment were developed and included in the forestry sub-sector's high and low bands, which then became inputs into the Monte Carlo uncertainty analysis. Table 7-11 shows the high, mid, and low forecasts before rate impacts.

Table 7-11 Chemical Segment Mid, High and Low Forecasts Before Rate Impacts

Fiscal year	High Forecast (GWh)	Mid Forecast (GWh)	Low Forecast (GWh)
Actual			
F2018	1,477	1,477	1,477
Forecast			
F2019[1]	1,374	1,350	1,325
F2020	1,472	1,349	1,288
F2021	1,471	1,349	1,288
F2022	1,469	1,347	1,286
F2023	1,469	1,347	1,286
F2024	1,470	1,347	1,286
5 Yr. Forecast (F18 to F23)	-0.1%	-1.8%	-2.6%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

There is relatively low uncertainty in the loads that make up the chemical segment. This is demonstrated in the historical sales between fiscal 2013 and fiscal 2018. Besides the aforementioned plant closure, there is little historical load variation. Going forward, we do not expect any material operational changes by customers within the chemical segment. We assume chemical plants have the ability to sustain operations by exporting product in the event there are pulp and paper mill curtailments in B.C. The high forecast is higher in magnitude relative to the mid forecast than is the low forecast. This is based on the assumption that prices and market conditions in the pulp and paper and oil and gas segments will be remain favourable.

7.4.3 Forestry forecast results

Sales to forestry customers have declined by 1,396 GWh or 17 per cent from fiscal 2013 to fiscal 2018[32]. This decrease occurred most in pulp and paper segment where a number of mill line closures occurred during this period. Table 7-12 shows the high, mid, and forecasts for the forestry sub-sector before rate impacts.

Table 7-12 Forestry Sub-Sector Mid, High and Low Forecasts Before Rate Impacts

Fiscal year	High Forecast (GWh)	Mid Forecast (GWh)	Low Forecast (GWh)
Actual			
F2018	6,954	6,954	6,954
Forecast			
F2019[1]	6,817	6,656	6,424
F2020	7,403	6,751	6,028
F2021	7,489	6,058	5,407
F2022	7,242	5,677	4,760
F2023	7,172	5,596	4,650
F2024	7,179	5,669	4,634
5 Yr. Forecast (F18 to F23)	0.6%	-4.3%	-6.6%

Table notes:

1. Forecast for fiscal 2019 does include any actuals.

For the period fiscal 2019 to fiscal 2021, the mid forecast of sales shows a decline of 598 GWh or 9 per cent. All segments contribute to this decline. From fiscal 2018 to fiscal 2024, mid sales are projected to decline by 1,285 GWh or 18 per cent. This decline is primarily due to reduced sales to the pulp and paper segment, which is driven by continued softening in demand for publication papers. The primary driver of variation in sales between the high and low forecasts is from publication paper mills. The asymmetrically wider high forecast is due to upside potential that could occur from publication paper mill lines successfully retooling production for new markets. The low forecast arises from mill and / or mill line closures in the pulp and paper and wood products segments.

[32] Forestry is the sum of pulp and paper segment, wood products and chemical segments as shown in Tables 7-22 to 7-24. The historical data indicates that sales to the forestry sub-sector were 8,351 GWh in Fiscal 2013 and 6,954 GWh in fiscal 2018, the difference between these two values over this time period is 1,396 GWh or 17 per cent.

7.5 OIL AND GAS

7.5.1 Oil and gas sub-sector description

Sales to the large industrial oil and gas sub-sector account for 11 per cent of the total large industrial sales. Electricity is used by oil and gas customers connected to the transmission system for various operations including refining and shipping petroleum, processing, natural gas production and liquid rich natural gas processing into various liquids. Most of the electricity is used to drive compressors for production and pipeline transportation.

The oil and gas sub-sector is categorized into two segments:

- shale gas (i.e. production/processing plants), and
- other large oil and gas operations.

The other large oil and gas operations consist of:

- conventional gas processing plants,
- oil (and condensate) pipelines,
- oil refineries and oil producers,
- natural gas pipelines,
- propane terminals, and
- LNG terminals.

Sales to LNG terminals are included in the other large oil and gas operations segment to maintain confidentiality on the specific nature of individual LNG projects included in the load forecast. This is consistent with our practice of not publishing specific customer history and forecast. The remainder of this section provides a summary of the forecast results for the entire sub-sector followed by a detailed discussion of the two major segments.

7.5.2 Oil and gas segment methodologies, forecasts results, and uncertainties

The methodology in the oil and gas sub-sector is consistent with the large industrial forecast process articulated in section 7.2. However, the depth of analysis carried out for each of the segments within the oil and gas sub-sector varies depending on segment size and complexity. For example, we apply a more robust and detailed analytical approach for the large and growing shale gas segment; conversely we adopt a less rigorous approach for the oil refineries and oil producer sub-segments, which are relatively small and static. Overall, each segment forecast is developed on an individual customer account basis, with probabilities applied, to develop an expected load forecast.

7.5.2.1 Shale gas

7.5.2.1.1 Shale gas segment description

In fiscal 2018 electricity sales to the shale gas segment represented 47 per cent of the total oil and gas sub-sector sales and 5 per cent of large industrial sales. Electricity is mainly used to drive plant compression and processing requirements.

The shale gas segment includes the production of raw natural gas from shale or tight sedimentary formations located in the B.C. Montney shale basin. The process starts with drilling wells into the formations using hydraulic fracturing techniques to access the gas. Since this technique differs from the older conventional process, gas produced in this manner is also called unconventional gas. Gas from these wells, is under high pressure, and is connected to gathering pipes which bring the gas to gas plants. These plants (increasingly being served by BC Hydro), perform light processing of the gas including refrigeration if needed to recover gas liquids (propane, butane and condensates).

7.5.2.1.2 Shale gas methodology

Consistent with the large industrial sector methodology, the shale gas segment is forecast on an individual customer account basis. However, the shale gas segment is the fastest growing within our large industrial sector, and given the complex nature of the industry requires more detailed analysis relative to other industrial sectors. A comprehensive analytical framework is used to directly link BC Hydro's internal assessment of customer accounts and new service requests (i.e., bottom up assessment) with supply and demand outlooks for natural gas, natural gas liquids and oil natural gas production forecasts developed by third party industry experts (i.e., top down assessment).

The main process steps are as follows:

- organize customer load requests into regional load forecasts,
- for the same regions, convert third-party gas production forecast to equivalent electrical loads estimates, and
- align the customer requested and expert produced forecasts by adjusting probability assessments and market assumptions, respectively, until they produce similar results.

This process produces a customer forecast that is supported by industry expert and market assumptions.

As noted in section 3.2.6, we retained the services of an oil and gas consulting company (GLJ Petroleum Consultants) to enhance our existing analysis.

The industry expert information provided by the consultant along with market intelligence information provided various subscription services and publicly available sources improves the performance of our assumptions.

7.5.2.1.3 Shale gas forecast results

Over the past five years ending fiscal 2018, sales to the shale gas segment have increased by 594 GWh or 511 per cent. Table 7-13 shows the history and forecast of sales before rate impacts.

Table 7-13 Shale Gas Segment Sales History and Forecast Before Rate Impacts

Fiscal year	October 2018 Forecast (GWh)
Actual	
F2013	116
F2014	261
F2015	280
F2016	440
F2017	549
F2018	710

Forecast	
F2019[1]	1,418
F2020	1,759
F2021	1,953
F2022	2,197
F2023	2,556
F2024	2,782
5 Yr. Actual (F13 to F18)	43.7%
5 Yr. Forecast (F18 to F23)	29.2%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

From fiscal 2018 to fiscal 2021 sales are forecast to increase by 1,243 GWh or 175 per cent. This increase is primarily driven from projects that recently started commercial operations or are currently under construction and are expected to come into service by fiscal 2021.

From fiscal 2018 to fiscal 2024, sales are projected to increase by 2,072 GWh or 292 per cent. As above, most of this growth (1,800 GWh) is driven by recently started and committed projects supplying the natural gas liquids market. While some of the other growth is related to plants that will be supplying downstream LNG operations.

Broadly speaking, our analysis leads us to believe that much of the increase in global natural gas supply will occur in North America. In this context, B.C.'s Montney shale basin is considered to be a competitive low cost gas supplier as the basin's size, productivity and mix of liquids enables it to compete with other sources of gas supply. The consultant reported that the basin's competitiveness is not considered to be dependent on access to LNG markets and forecasts continued natural gas production growth in B.C. with an increasing share of the Western Canadian gas supply market.

7.5.2.1.4 Shale Gas Uncertainties

While additional load growth potential is relatively low in the short term, there is significant, albeit uncertain long term potential. The potential downside is considered low for both the near and long term. Upside and downside risks include the following:

Upside risks include:

- future North American LNG development (B.C., U.S. west coast and U.S. gulf coast) increasing demand for B.C. natural gas,
- continued expansion of Alberta oil sands and associated demand for gas liquids,
- continued displacement of net U.S. gas liquids imports to Alberta with B.C. gas liquids, and
- higher than expected natural gas, liquids, and oil prices.

Downside risks include:

- condensate production in Alberta (large basin in Western central Alberta has a logistical advantage to oil sands producers than B.C. producers),
- Alberta importation of U.S. condensate for heavy oil productions (threatens B.C. producer growth),
- increased gas liquids production in Alberta (closer to petrochemical plants in Alberta),
- lower than expected natural gas prices caused by increased natural gas production in other North American production regions, and
- delay of LNG terminal operational dates.

Table 7-14 shows the high, mid, and low forecast of sales to the Shale Gas segment before rate impacts.

Table 7-14 Shale Gas Segment Mid, High and Low Forecasts Before Rate Impacts

Fiscal year	High Forecast (GWh)	Mid Forecast (GWh)	Low Forecast (GWh)
Actual			
F2018	710	710	710
Forecast			
F2019[1]	1,529	1,418	1,207
F2020	1,972	1,759	1,505
F2021	2,114	1,953	1,669
F2022	2,491	2,197	1,709
F2023	3,016	2,556	1,761
F2024	3,735	2,782	1,906
5 Yr. Forecast (F18 to F23)	33.6%	29.2%	19.9%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

High and low forecasts for the shale gas segment were developed and included in the high and low forecasts oil and gas sub-sectors as inputs in the Monte Carlo uncertainty analysis.

The high shale gas forecast assumes higher natural gas production growth to serve higher LNG terminal requirements, higher downstream gas and liquids exports to stronger North American markets and higher electrification percentages for new production facilities. The low shale gas forecast assumes slower production growth trending rise in natural gas production to supply lower LNG terminal requirements, weaker North American natural gas demand, and lower electrification percentage for new production facilities.

7.5.2.2 Other large oil and gas operations

7.5.2.2.1 Other large oil and gas operations segment description

Sales to the other large oil and gas operations segment represents 53 per cent of all the sales to the oil and gas sub-sector and 6 per cent of all Large Industrial sector sales. This segment consists of the following facility types:

- Conventional gas processing plants,
- Oil (and condensate) pipelines,
- Oil refineries and oil producers,
- Natural gas pipelines,
- Propane terminals, and
- LNG terminals.

Conventional gas processing plants comprises 16 per cent of BC Hydro's sales to the oil and gas sub-sector. These customers use conventional means to recover gas, perform gas liquids extraction (ethane, propane, butane and pentane) and extract acid gases. Historically, the processors have served conventional gas producers. However, conventional gas production in B.C. has been declining over the past 10 years and as conventionally gas production declines, processing plants are increasingly being supplied by shale gas producers.

Oil pipelines constitute 13 per cent of BC Hydro's sales to the oil and gas sub-sector. These customers operate pipelines which serve to transport crude oil and petroleum products. Electricity is primarily used in pumping stations with power sales being correlated to the volume of liquids shipped. Future growth opportunities for this industry are due to B.C.'s proximity to Asian oil markets where oil demand is increasing and U.S. west coast oil refineries.

Oil refineries and oil producers currently make up 23 per cent of BC Hydro's sales to the oil and gas sub-sector. These customers include tank farms, oil refineries (which also produce gasoline and jet fuel) and oil producers. Electricity sales are related to B.C.'s oil pipeline shipments and to a lesser degree oil prices.

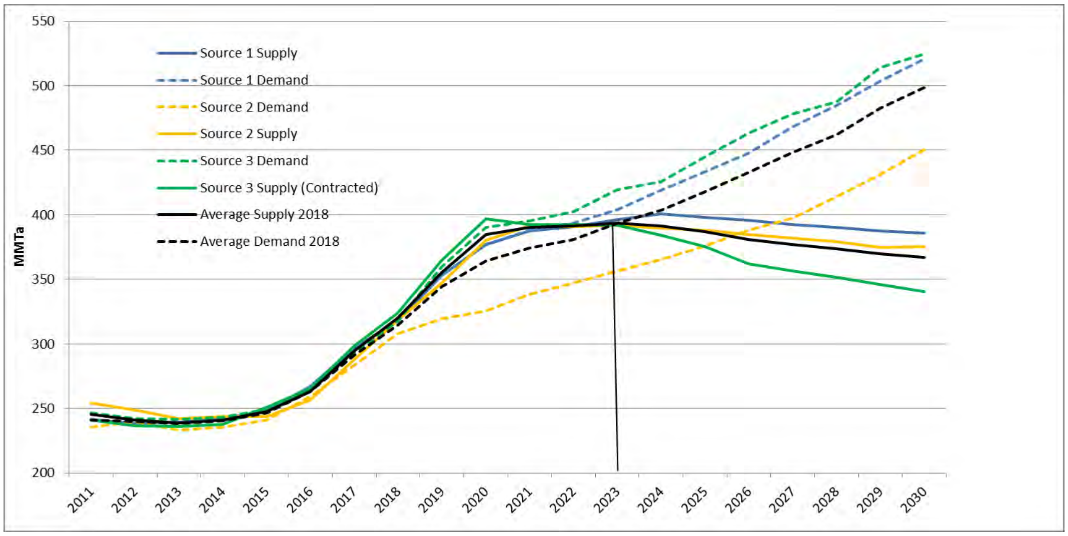
Natural gas pipelines encompass 1 per cent of BC Hydro's sales in the oil and gas sub-sector. These customers ship natural gas via pipeline. Natural gas pipelines use gas compressors instead of electrically-driven compressor to power booster stations.

Propane terminals are an emerging B.C. industry with two new terminals currently under construction. When construction is complete, these customers will receive the propane by rail, store it in tanks and then pump the propane from the terminals onto ships for export. Our industry consultant produced a B.C. propane terminal supply analysis, which was used to inform the propane terminal forecast. Electricity will be used for pumps and compressors with future sales related to world propane prices, Asian demand and B.C. terminal propane. Propane supply is expected to be sourced from the B.C. Montney and the Alberta Duverney shale gas basins.

LNG is natural gas that has been cooled to a liquid state, at about negative160 degrees celsius, for shipping and storage. The volume of natural gas in its liquid state is hundreds of times smaller than its volume in its gaseous state. This process, allows the transportation of natural gas to places pipelines do not reach. LNG is shipped in special tankers between export terminals, where natural gas is liquefied, and import terminals, where LNG is returned to its gaseous state (regasified).

British Columbia has the advantage of shorter shipping distances to Asia relative to other LNG supplier, and significant natural gas reserves including the Montney, Horn River and Liard formations. After an initial boom in global LNG project development, global LNG investment decreased following a drop in LNG prices in 2014. Investment appetite was further diminished by fears of an extended supply surplus. British Columbia's LNG sector followed similar pattern with the more than 20 LNG project proposals, followed by a number of project cancellations. More recently there has been a dramatic shift in the market outlook as higher than expected demand for LNG in growing economies such as China and India has reversed the supply/demand balance from one of extended supply surplus to supply deficit within five years. Based on an aggregation of market outlooks from different subscription sources, the current supply/demand balance is expected to occur around 2023. This is illustrated in Figure 7-3.

Figure 7-3 Global LNG Supply – Demand Balance



Over the past few years, BC Hydro and the provincial government have been closely working with LNG proponents on options for meeting energy needs of LNG plants with power from the BC Hydro system. LNG-related electricity demand falls into two general categories: compression and non-compression. The compression energy is about 85 per cent of the total plant's energy needs. The remaining (non-compression) energy requirement is from plant pumps, motors, other equipment, heating and lighting. Compression energy is typically supplied with direct-drive natural gas turbines, although this can also be accomplished with electric drives.

In October 2018, LNG Canada announced a positive final investment decision to proceed with its project located in Kitimat, B.C. LNG Canada is the single largest private sector investment project in Canadian history. The first phase of the project includes a $6.2-billion natural gas pipeline through northern British Columbia and an $18-billion liquefaction facility in Kitimat, B.C.

In addition to LNG Canada, a number of other B.C. based LNG projects are continuing to advance. These include Woodfibre LNG, Kitimat LNG and Kwispaa. FortisBC's Tilbury LNG plant is operating and taking electricity service from BC Hydro.

7.5.2.2.2 Other large oil and gas operations methodology

Consistent with the large industrial sector methodology, the other large oil and gas sector is forecast on an individual customer account basis. Within this customer based forecasting process, various calculation techniques are used to arrive at the customer's energy and peak forecasts.

The primary method is the product of expected peak demand, load factor and probability. The load factor is a measure of the utilization rate, or efficiency of electrical energy usage. Generally, the underlying drivers of the forecast are the customer's requested load, estimated operational hours, historical load patterns and operational probabilities. In case of existing customers, historical consumption information is used as starting reference point updated with newest information (such as facility expansion or contraction plans). The probability weightings are informed by considerations such as the project's economics, availability of financing, regulatory progress and BC Hydro interconnection status. A facility's economics is analyzed in the context of the market outlooks informed by external and internal information. For the current forecast, BC Hydro relies on the following subscription services:

- Bloomberg,
    - Terminal

  - New Energy Finance
- Wood Mackenzie North America Gas Service,
- IHS Connect, and
- RBN Energy's paid for information services on North American: oil, natural gas liquids, natural gas and the Permian basin.

Additional information was obtained through an oil and gas consultant. This information included:

- B.C. conventional gas basin forecasts,
- oil price forecasts and Alberta oil supply forecasts,
- reporting on natural gas pipeline development, and
- analysis on B.C. propane terminal propane supply.

LNG customers are included in the large oil and gas segment to protect the confidentiality of our assessment of LNG projects. In developing the LNG forecasts we continue to include in the forecast only those LNG projects that are already operational or have requested service. Probably assessments of individual LNG projects were developed based on:

- professional input from Key Account Management, Load Interconnections and Customer Service business units, and
- third party expert assessments of the global LNG market, relative competitiveness of B.C. LNG, and specific B.C. projects.

To do this we rely on the Wood Mackenzie LNG, Bloomberg LNG and IHS LNG subscriptions, as well as information from publically available sources such as McKinsey's Energy Insight, National Energy Board, International Energy Agency, Canadian Energy Research Institute.

In line with how we forecast other large industrial sectors, the probability assessment informs a binary "in/out" call in the first three years of the forecast period and then a probability weighted forecast for the remainder of the forecast period.

7.5.2.2.3 Other large oil and gas operations forecast results

Over the past five years ending fiscal 2018, sales to the other large oil and gas segment declined by 47 GWh or 6 per cent. The decline is primarily due to lower sales to conventional gas producers and processors. These customers have been impacted by the downward trend in natural gas prices that have occurred during this period. Table 7-15 below shows the actual and forecast before rate impact to the other oil and gas segment.

Table 7-15 Other Large Oil and Gas Operations Segment Sales History and Forecast Before Rate Impacts

Fiscal year	October 2018 Forecast (GWh)
Actual	
F2013	845
F2014	771
F2015	835
F2016	836

F2017	824
F2018	798
Forecast	
F2019[1]	914
F2020	1,011
F2021	1,045
F2022	1,105
F2023	1,198
F2024	2,063
5 Yr. Actual (F13 to F18)	-1.1%
5 Yr. Forecast (F18 to F23)	8.5%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

From fiscal 2019 to fiscal 2021, sales are forecast to increase by 130 GWh or 14 per cent. This is primarily due to sales related to LNG terminals and conventional gas processing plants. From fiscal 2018 to fiscal 2024, sales increase by 1,265 GWh or 159 per cent. This growth is attributed to sales to LNG terminals, pipelines and conventional processing plants.

Publically available information on LNG projects is included in our load forecast:

- LNG Canada recently made a positive final investment decision. Only construction-related load from this LNG facility is expected within the window of our load forecast.
- Woodfibre LNG decision to proceed with the project has not been yet announced. We included a probability weighted sales forecast from this facility in our load forecast.
- FortisBC Tilbury is in operation and we included forecast sales to this LNG facility.

7.5.2.2.4 Other large oil and gas operations uncertainties

The various industries making up this segment face somewhat different risks and uncertainties. This is because the products and markets within the sub-segments are different. The description for the major risks is provided below. LNG-related risks are described separately.

The risks associated with the large oil and gas operations, excluding LNG terminals, collectively tend to weigh more on the downside than the high side in terms of potential impacts to BC Hydro sales.

The upside risks include:

- Higher than expected Asian demand for propane would incent propane terminal expansions in B.C.,
- Higher than expected oil sands transport venues and expanded fossil fuel processing capacity in Alberta would stimulate the conventional gas processing plants to recover more natural gas liquids,
- Higher than expected oil prices would increase B.C. oil refinery oil production and oil pipeline activity, and
- Minimal fossil fuel related construction delays would lower perceived risk and incent further development.

The downside risks include:

- Oversupply of fossil fuels in global, Alberta and U.S. markets and lower than expected prices to B.C. producers. This will cause B.C. oil refineries, oil producers and conventional gas processing plants to reduce production, defer new projects, and shut plants,
- New gas liquids pipeline from the U.S. into Alberta. This will reduce profit margins for B.C. producers and reduce conventional gas processing plants activity, and
- Longer than expected infrastructure construction delays or project cancellations.

For LNG terminals, the major risks are identified below. Notwithstanding LNG Canada's positive investment decision, LNG development in B.C. remains an emerging industry with significant but uncertain growth potential. The risk profile for this industry is asymmetrical in that the potential for higher load growth relative to what is reflected in the load forecast is greater than the potential for lower load. Various risks that have can have either positive or negative impacts on B.C. LNG development include:

- Federal/provincial policies that support or restrict domestic LNG development,
- Large upturns/downturns in the energy markets leading to unexpected supply surpluses or deficits,
- Legislation that supports or restricts nuclear power in Japan and coal generation in China,
- Climate action policies that increase or decrease global demand for natural gas, and
- Competition with U.S. based LNG and other major LNG export countries.

High and low forecasts for the other oil and gas operations segment, were developed and aggregated within the high and low forecasts for the oil and gas sub-sector for inputs into the Monte Carlo uncertainty analysis.

Table 7-16 shows the mid, high and low forecast before rate impacts.

Table 7-16 Other Large Oil and Gas Operations Segment Mid, High and Low Forecasts Before Rate Impacts

Fiscal year	High Forecast (GWh)	Mid Forecast (GWh)	Low Forecast (GWh)
Actual			
F2018	798	798	798
Forecast			
F2019[1]	946	914	858
F2020	1,082	1,011	876

F2021	1,120	1,045	913
F2022	1,238	1,105	963
F2023	2,369	1,198	1,043
F2024	2,929	2,063	1,367
5 Yr. Forecast (F18 to F23)	24.3%	8.5%	5.5%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

The risk profile for this segment is asymmetrical in that the potential for higher load growth relative to what is reflected in the load forecast is greater than the potential for lower load. This asymmetry is primarily due to LNG terminals.

7.5.3 Oil and gas sub-sector forecast results

Over the past five years ending fiscal 2018, sales to the large industrial oil and gas sub-sector have increased by 546 GWh or 57 per cent. This based on the combined total of sales to shale and other large oil and gas customers as shown in Table 7-23 in section 7.8. This increase is primarily due to growth in the shale gas segment, which itself is driven by demand for gas liquids present in B.C.'s Montney shale basin. Table 7-17 shows the mid, high and low forecast before rate impacts for this sub-sector.

Table 7-17 Oil and Gas Sub-Sector Mid, High and Low Forecasts Before Rate Impacts

Fiscal year	High Forecast (GWh)	Mid Forecast (GWh)	Low Forecast (GWh)
Actual			
F2018	1,507	1,507	1,507
Forecast			
F2019[1]	2,475	2,332	2,065
F2020	3,055	2,770	2,382
F2021	3,233	2,998	2,583
F2022	3,729	3,301	2,673
F2023	5, 385	3,753	2,804
F2024	6,664	4,845	3,272

5 Yr. Forecast (F18 to F23)	29.0%	20.0%	13.2%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

From fiscal 2018 to fiscal 2021, the expected (mid) sales are forecast to grow significantly by 1,490 GWh or 99 per cent. This growth is primarily driven by new shale gas production plants that: have switched to BC Hydro service, have started operations and are ramping up production or are under construction. The forecast of mid sales from fiscal 2018 to fiscal 2024 are projected to increase by 3,338 GWh or 221 per cent.

Although the oil and gas sub-sector is comprised of customers all related to the fossil fuel industry, the major risks and uncertainties for each are generally different. This is because the products and markets within the segments and sub-segments are different. Nevertheless, the risk profile for this segment is asymmetrical in that the potential for higher load growth relative to what is reflected in the load forecast is greater than the potential for lower load. This asymmetry is due to LNG terminals and pipelines, as well as potential for increased electrification in natural gas production and processing associated with the recently announced CleanBC Plan.

7.6 OTHER LARGE INDUSTRIAL

7.6.1 Other large industrial sub-sector description

The other industrial sub-sector is comprised of a range of customers from universities, ports, terminals and wire manufacturers to cement companies and water pumping stations. The other industrial sub-sector also includes incremental cannabis and cryptocurrency loads that we expect to be connected at transmission voltages. More detail on cannabis and cryptocurrency loads is found in Section 8.

7.6.2 Other large industrial methodology

Customers in the other category are forecast on an individual customer account basis consistent with the large industrial sector methodology. However, this sub-sector forecast is not directly informed by specific commodity price or market outlooks due to sub-sector's diversity. The forecast is primarily based on customer information provided via our Key Accounts Management and Interconnection business units.

7.6.3 Other large industrial forecast results

Over the past five years ending fiscal 2018, sales to the Other Large Industrial segment increased by 54 GWh or 0.9 per cent. This was caused by increased load and equipment upgrade made by existing customers. Table 7-18 shows the total forecast of the other large industrial sub-sector, with the transmission voltage connected cannabis and cryptocurrency loads presented separately. All forecast are before rate impacts.

Table 7-18 Other Large Industrial Sub-Sector Sales History and Forecast Before Rate Impacts

Fiscal year	October 2018 Other Large Industrial Customers Excluding Cannabis and Cryptocurrency(GWh)	October 2018 Cannabis and Cryptocurrency Load Additions (GWh)[1]	October 2018 Total Large Industrial Sub-sector (GWh)
Actual			
F2013	1,117		1,117

F2014	1,177		1,177
F2015	1,173		1,173
F2016	1,149		1,149
F2017	1,126		1,126
F2018	1,171		1,171
Forecast			
F2019[2]	1,145	66	1,211
F2020	1,181	375	1,556
F2021	1,213	403	1,616
F2022	1,226	403	1,630
F2023	1,233	403	1,636
F2024	1,245	403	1,649
5 Yr. Historical (F13 to F18)	0.9%		0.9%
5 Yr. Forecast (F18 to F23)	1.0%		6.9%

Table notes:

1. As of fiscal 2018 there were no light industrial customers classified as cannabis and cryptocurrency loads. As such, historical and forecast compound growth rates are not shown on the table above.
2. Forecast for fiscal 2019 does not include any actuals.

The growth in the other sub-sector between fiscal 2018 and fiscal 2024 is primarily driven by new cannabis and cryptocurrency operations connected at the transmission service level. These operations account for approximately 400 GWh of the overall sub-sector growth over the period. However, given the unique characteristics of cannabis and cryptocurrency loads as emerging industries we describe them separately in Section 8.

In addition to transmission-connected cannabis and cryptocurrency, there is a small amount of growth over the entire forecast period which is primarily due to upgrades and expansions from other existing customers in this sub-sector.

7.6.4 Other large industrial uncertainties

The major uncertainties around the other large industrial loads include:

- uncertainty in cannabis and cryptocurrency (See Section 8),
- economic growth and construction activity, which in turn affects the demand for cement and other industrial products,
- sectorial shifts in B.C. economy (e.g., shift from manufacturing to services, emerging sectors such as data centres, cannabis or cryptocurrency), and
- slowdown or increase in shipping.

The high and low load forecasts for the other large industrial sub-sector were developed and included Monte Carlo uncertainty analysis.

The high forecast was developed based on the following assumptions:

- higher global economic growth results in higher demand for industrial products and shipping affecting cement plant production, ports, terminals and manufacturing, and
- higher than anticipated growth for universities and new customers.

The low forecast was developed based on the following assumptions:

- lower global economic growth results in lower demand for products and shipping affecting cement plant production, ports, terminals and manufacturing, and
- universities, airports and municipal customers remain flat.

Table 7-19 shows the high, mid, and low forecasts for the other large industrial customers (excluding cannabis and cryptocurrency) before rate impacts. The high and low other large industrial load forecasts were developed and included as inputs into the Monte Carlo uncertainty analysis. Table 7-19 shows the high, mid, and low forecasts before rate impacts.

Table 7-19 Other Large Industrial Sub-Sector Mid, High, Low Forecasts Before Rate Impacts

Fiscal year	High Forecast (GWh)[1]	Mid Forecast (GWh)	Low Forecast (GWh)[1]
Actual			
F2018	1,171	1,171	1,171
Forecast			
F2019[1]	1,167	1,145	1,135
F2020	1,231	1,179	1,129
F2021	1,290	1,210	1,122
F2022	1,306	1,226	1,122
F2023	1,312	1,233	1,122
F2024	1,324	1,245	1,122

5 Yr. Forecast (F18 to F23)	2.3%	1.0%	-0.9%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

7.7 LARGE INDUSTRIAL LOAD FORECAST BUILD-UP F2019 TO F2021

The following tables show the build-up of the Large Industrial Load Forecast for fiscal 2019 and the test years of our F20-F21 RRA.

Table 7-20 Fiscal 2019 Large Industrial Sector Load Forecast Buildup

Large Customer Forecast GWh[1]	Fuel Switching Load Additions (GWh)	Rate Impact[2] (GWh)	DSM (GWh)	Large Industrial Load Forecast (GWh)[3]
14,024	1	(5)	(164)	13,856

Table notes:

1. Large industrial customer forecast is the sum total of the individual customer forecasts for all sub-sectors.
2. Rate Impacts are load reductions based on formula that include our real rate increase projection, a price elasticity assumption of -0.1 and the large industrial customer forecast and the large industrial load additions.
3. Large Industrial Load Forecast is an aggregation of large industrial customer forecasts plus load additions less rate impacts less DSM savings.

The forecast value of 13,856 GWh for fiscal 2019 does not include any actuals over the current fiscal year, while the forecast of 13,810 GWh, as shown in the executive summary, reflects six months actual billed sales and six months forecast. To derive this value, the load forecast for the sub-sectors were allocated into 12 months and the first six months of forecast are replaced with actuals billed sales.

Table 7-21 Fiscal 2020 and Fiscal 2021 Large Industrial Sector Sales Forecast Buildup

Large Industrial Customer Forecasts GWh[1]	Fuel Switching Load Additions (GWh)	Rate Impacts[2] (GWh)	DSM (GWh)	Large Industrial Load Forecast[3] (GWh)
15,056	5	(12)	(347)	14,702
14,675	65	(20)	(477)	14,243

Table notes:

1. Large industrial customer forecast is the sum total of the individual customer forecasts for all sub-sectors.
2. Rate Impacts are load reductions based on formula that include our real rate increase projection, a price elasticity assumption of -0.1 and the large industrial customer forecast and the large industrial load additions.

3. Large Industrial Load Forecast is an aggregation of large industrial customer forecasts plus load additions less rate impacts less DSM savings.

7.8 LARGE INDUSTRIAL FORECASTS RESULTS

The next three tables in this section summarize the history and forecasts:

- before rate impacts,
- after rate impacts, and
- after rate impacts and DSM savings

for the large industrial sector, its sub-sectors and segments.

Table 7-22 Large Industrial Sales History and Forecast Before Rate Impacts

Fiscal year	Mining		Forestry			Oil and Gas		Other	Total
	Metal Mines (GWh)	Coal Mines (GWh)	Pulp and Paper (GWh)	Wood Products (GWh)	Chemical (GWh)	Shale Gas (GWh)	Other Oil and Gas (GWh)	Large Industrial (GWh)[1]	Large Industrial (GWh)
Actual									
F2013	2,561	541	5,611	1,164	1,575	116	845	1,117	13,530
F2014	2,978	551	5,506	1,148	1,580	261	771	1,177	13,972
F2015	3,247	560	5,262	1,155	1,541	280	835	1,173	14,055
F2016	3,338	545	4,726	1,208	1,456	440	836	1,149	13,698
F2017	3,321	562	4,173	1,141	1,409	549	824	1,126	13,106
F2018	3,291	589	4,234	1,243	1,477	710	797	1,171	13,513
Forecast									
F2019[2]	3,294	533	4,083	1,223	1,350	1,418	914	1,211	14,026
F2020	3,427	558	4,174	1,228	1,349	1,759	1,011	1,556	15,061
F2021	3,501	567	3,477	1,231	1,349	1,953	1,045	1,616	14,740
F2022	3,488	563	3,099	1,231	1,347	2,197	1,105	1,630	14,659
F2023	3,457	563	3,025	1,224	1,347	2,556	1,198	1,636	15,006
F2024	3,360	579	3,129	1,193	1,347	2,782	2,063	1,649	16,102
5 Yr. Actual (F13 to F18)	5.1%	1.7%	-5.5%	1.3%	-1.3%	43.7%	-1.1%	0.9%	0.0%
5 Yr. Forecast (F18 to F23)	1.0%	-0.9%	-6.5%	-0.3%	-1.8%	29.2%	8.5%	6.9%	2.1%

Table notes:

1. Other large industrial includes transmission connected cannabis and cryptocurrency loads.
2. Forecast for fiscal 2019 does not include any actuals.

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Table 7-23 Large Industrial Sales History and Forecast After Rate Impacts

Fiscal Year	Mining		Forestry			Oil and Gas		Other	Total
	Metal Mines (GWh)	Coal Mines (GWh)	Pulp and Paper (GWh)	Wood Products (GWh)	Chemical (GWh)	Shale Gas (GWh)	Other Oil and Gas (GWh)	Large Industrial (GWh)[1]	Large Industrial (GWh)
Actual									
F2013	2,561	541	5,611	1,164	1,575	116	845	1,117	13,530
F2014	2,978	551	5,506	1,148	1,580	261	771	1,177	13,972
F2015	3,247	560	5,262	1,155	1,541	280	835	1,173	14,055
F2016	3,338	545	4,726	1,208	1,456	440	836	1,149	13,698
F2017	3,321	562	4,173	1,141	1,409	549	824	1,126	13,106
F2018	3,291	589	4,234	1,243	1,477	797	710	1,171	13,513
Forecast									
F2019[2]	3,293	532	4,081	1,223	1,349	1,417	913	1,210	14,020
F2020	3,425	557	4,170	1,227	1,348	1,757	1,010	1,555	15,050
F2021	3,497	566	3,472	1,230	1,347	1,950	1,043	1,614	14,720
F2022	3,481	562	3,093	1,229	1,345	2,192	1,103	1,626	14,631
F2023	3,448	562	3,017	1,221	1,344	2,549	1,195	1,632	14,969
F2024	3,349	577	3,119	1,190	1,343	2,773	2,058	1,644	16,054
5 Yr. Actual (F13 to 18)	5.1%	1.7%	-5.5%	1.3%	-1.3%	43.7%	-1.2%	0.9%	0.0%
5 Yr. Forecast (F18 to 23)	0.9%	-0.9%	-6.6%	-0.4%	-1.9%	29.1%	8.4%	6.9%	2.1%

Table notes:

1. Other large industrial includes transmission connected cannabis and cryptocurrency loads.
2. Forecast for fiscal 2019 does not include any actuals.

Table 7-24 Large Industrial Sales History and Forecast After Rate Impacts and After DSM

Fiscal Year	Mining		Forestry			Oil and Gas		Other	Total
	Metal Mines (GWh)	Coal Mines (GWh)	Pulp and Paper (GWh)	Wood Products (GWh)	Chemical (GWh)	Shale Gas (GWh)	Other Oil and Gas (GWh)	Large Industrial (GWh)[1]	Large Industrial (GWh)
Actual									
F2013	2,561	541	5,611	1,164	1,575	116	845	1,117	13,530
F2014	2,978	551	5,506	1,148	1,580	261	771	1,177	13,972
F2015	3,247	560	5,262	1,155	1,541	280	835	1,173	14,055
F2016	3,338	545	4,726	1,208	1,456	440	836	1,149	13,698
F2017	3,321	562	4,173	1,141	1,409	549	824	1,126	13,106
F2018	3,291	589	4,234	1,243	1,477	797	710	1,171	13,513
Forecast									
F2019[2]	3,255	526	3,988	1,215	1,349	`1,410	909	1,203	13,856
F2020	3,340	544	3,982	1,210	1,348	1,740	1,001	1,537	14,702
F2021	3,387	549	3,206	1,208	1,347	1,927	1,032	1,588	14,243
F2022	3,357	542	2,768	1,205	1,345	2,165	1,090	1,594	14,066
F2023	3,315	540	2,682	1,195	1,344	2,518	1,183	1,594	14,371
F2024	3,204	552	2,769	1,161	1,343	2,742	2,042	1,600	15,414
5 Yr. Actual (F13 to F18)	5.1%	1.7%	-5.5%	1.3%	-1.3%	43.7%	-1.2%	0.9%	0.0%
5 Yr. Forecast (F18 to F23)	0.1%	-1.7%	-8.7%	-0.8%	-1.9%	28.8%	8,2%	6.4%	1.2%

Table notes:

1. Other large industrial includes transmission connected cannabis and cryptocurrency loads.
2. Forecast for fiscal 2019 does not include any actuals.

8.0 Cannabis and Cryptocurrency Forecast

8.1 EMERGING INDUSTRIES DESCRIPTION

As emerging industries, loads from cannabis and cryptocurrency customers are included as separate load additions to the October 2018 Load Forecast. The forecast for these loads are incremental to base year fiscal 2018. While there are existing cannabis operations that pre-date the passing of legislation legalizing cannabis production and use, the intent of this chapter is to summarize the expected incremental load growth associated with legalization. Existing loads are recognized in the forecast as well as additional incremental loads that are not part of the fiscal 2018 base year. The approach has been applied to cryptocurrency as well; there are some existing loads in the base year that have transitioned into operations in addition to new, incremental loads.

The aggregated cannabis and cryptocurrency load forecast is made up of individual customer loads connected at both transmission and distribution levels of service. However, for the overall Load Forecast, these loads are incorporated as follows:

- customer loads connected at the transmission service level are incorporated within the other large industrial sub-sector category, and
- customer loads connected at distribution service level are incorporated within the other light industrial sub-sector category.

8.1.1 Cannabis

In October 2018, the Government of Canada enacted the *Cannabis Act*, which began the process of winding down the prohibition of non-medical cannabis in Canada. The *Cannabis Act* provides a framework for the production, distribution and sale of cannabis. The Government of B.C. outlined a series of regulations in the *Cannabis Distribution Act*, which creates a public wholesale distribution monopoly, and *Cannabis Control and Licensing Act*, which outlines the rules for consumption.

Two of Canada's largest cannabis product suppliers are Vancouver-based Aurora Cannabis Inc. and Nanaimo-based Tilray. For a brief period in September 2018, Tilray held the number one spot as the world's most valuable cannabis producer company, surpassing US-based Canopy with a $14 billion market capitalization.

According to Arcview Market Research and its research partner BDS Analytics, consumer spending on legal cannabis worldwide is expected to hit $57 billion by 2027.[33] Within this consumer demand, the recreational market is expected to make up two-thirds of the spending while medical marijuana is expected to make up the remaining third. North America will continue to represent the largest spending volume, with sales going from $9.2 billion in 2017 to $47.3 billion a decade later.

8.1.2 Cryptocurrencies

Cryptocurrencies are electronic peer-to-peer currencies that have value and trade on a virtual marketplace. Cryptocurrencies operate outside of traditional financial institutions by trading through blockchain technology. Blockchain is a digital infrastructure that acts as an electronic ledger for cryptocurrencies, and facilitates the transfer of cryptocurrency. Participants in the cryptocurrency market often call themselves miners, because they operate high-powered computers who compete with other participants to solve complex mathematical equations to store and conduct cryptocurrency transactions.

[33] https://bdsanalytics.com/press/new-report-worldwide-spending-on-legal-cannabis-will-reach-57-billion-by-2027/

Before 2018, China accounted for the majority of cryptocurrency mining globally. However, in an effort to alleviate demands on its electrical system, China has implemented regulations that have effectively caused crypto miners to explore moving their operations to other jurisdictions, including British Columbia.

8.2 CANNABIS AND CRYPTOCURRENCY METHODOLOGY

BC Hydro has received a large number of formal requests for service and general inquiries from both cannabis and cryptocurrency operations. By September 2018, the total number of general inquiries for both types of load approached a combined total of 20,000 GWh, illustrated in Table 8-1 below. The table includes two categories, one showing the total level of general inquiries by sector, the other one showing the total level of customer service requests received by the Load Interconnections group.

Notwithstanding the large number of service requests and inquiries, we adopted a conservative approach to developing the load forecast by only including loads that meet the following criteria:

- the loads are associated with customer service requests that are in advanced stages of our load interconnection process, and
- of those service requests, BC Hydro considers the customer's project to have a very high probability of proceeding.

A short list of projects meeting the first criteria was assembled and collaboratively reviewed to determine a high likelihood of proceeding by a number of business units, including Load Forecasting, Key Account Management, Distribution Planning and Economic Development.

Table 8-1 Cannabis & Cryptocurrency Inquiries and Service Requests

Status as of September 2018		
Cryptocurrency	**MW**	**GWh**
General Inquiry	1,892	14,088
Formal service requests/Interconnection Applications	87	648
Cannabis	**MW**	**GWh**
General Inquiry	873	4,971
Formal service requests/Interconnection Applications	177	1,008

8.3 CANNABIS AND CRYPTOCURRENCY FORECAST RESULTS

Table 8-2 below shows the incremental total of cannabis and cryptocurrency loads at the transmission and distribution voltage level included in the October 2018 Load Forecast before rate impacts and DSM savings. This combined load is expected to increase to 650 GWh by F2021.

Table 8-2 Cannabis and Cryptocurrency Forecast Before Rate Impacts

Fiscal year	October 2018 cannabis and cryptocurrency load transmission connected (GWh)[1]	October 2018 cannabis and cryptocurrency load distribution connected (GWh)[1]	October 2018 cannabis and cryptocurrency total load (GWh)[1]
	A	B	A+B
Actual			
F2018	N/A	N/A	N/A
Forecast			
F2019[2]	66	42	108
F2020	375	79	453
F2021	403	242	646
F2022	403	244	648
F2023	403	246	649
F2024	403	247	650
5 Yr. Forecast (F18 to F23)	N/A	N/A	N/A

Table notes:

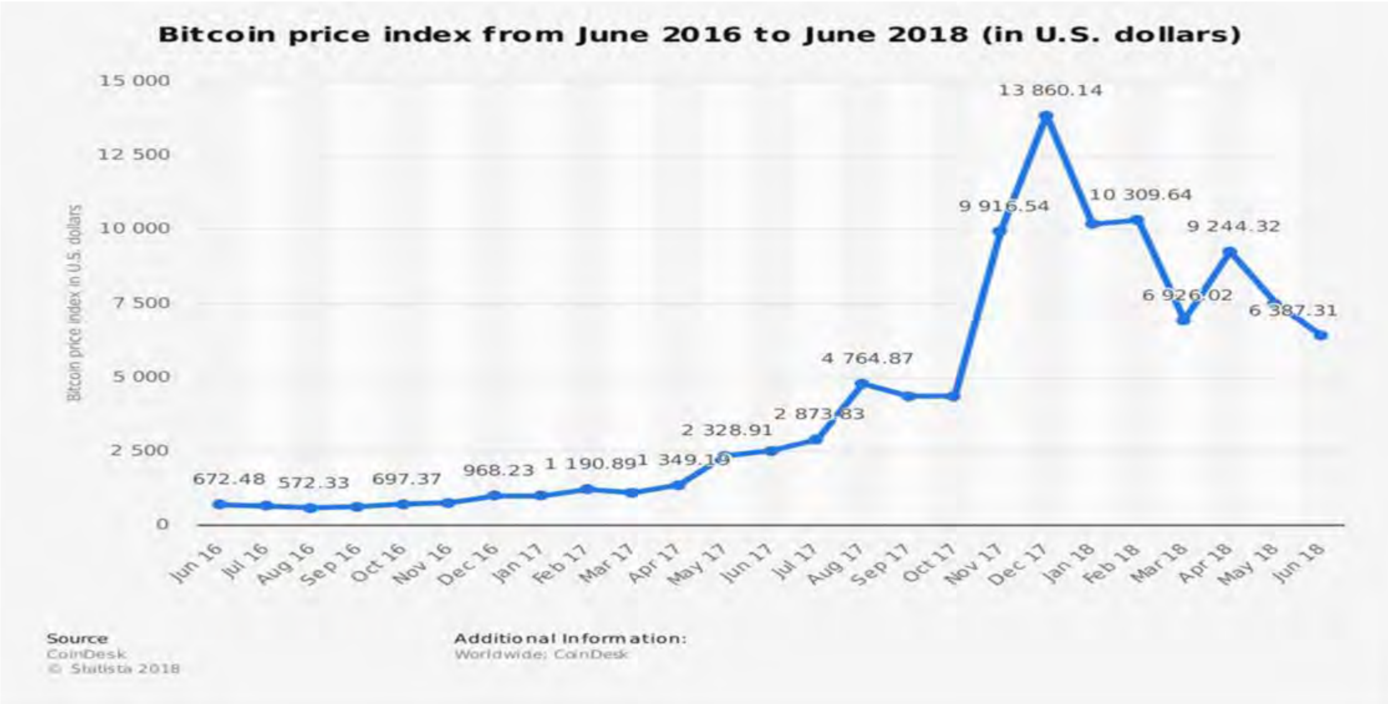
1. N/A means that there were no customers classified as cannabis or cryptocurrency as part of our historical sales in fiscal 2018 or earlier. As such, the historical data to compute growth rate is not applicable.
2. Forecast for fiscal 2019 does not include any actuals.

8.4 CANNABIS AND CRYPTOCURRENCY UNCERTAINTIES

Cannabis and cryptocurrency are both emerging industries where there is minimal existing load and significant, albeit, uncertain growth potential. The risk profile for these industries is asymmetrical in that the potential for higher load growth relative to what is reflected in the load forecast is greater than the potential for lower load. However, little consensus exists about the future of cannabis and cryptocurrency's pace of growth. This is acutely the case for cryptocurrency.

The risk that cryptocurrency loads included in the forecast will not materialize or existing operations will cease operations during the forecast period is the largest risk associated with this emerging industries load forecast. The business viability is ultimately dependent on cryptocurrency prices which are extremely volatile. Figure 8-2 shows the bitcoin price index from 2016-2018.

Figure 8-1 Bitcoin Price Index June 2016 to June 2018



This figure highlights the significant price volatility associated with cryptocurrencies, such as bitcoin; and is indicative of the uncertainty associated with cryptocurrency mining as a sustainable growth industry. Cryptocurrency exchanges also face regulatory risks as governments are taking various actions to mitigate customer exposure to fraud and unlawful business practices. Given this, the regulatory environment can affect the international development of cryptocurrency. In March 2018, bitcoin prices fell below $10,000 after the Securities and Exchange Commission announced the requirement that digital asset exchanges must register with the agency. The Canadian government has postponed the release of its final regulations for cryptocurrency and block-chain companies initially announced for August 2018. Depending on the nature of the regulations this could either help or hinder the development of the cryptocurrency industry as well impact the development of the load.

In contrast, cannabis loads reflected in the load forecast are exposed to significantly less uncertainty. Reasons for this include:

- most of the cannabis operations included in the forecast have long-term agreements for their product or own their site locations, and
- a large cannabis load included in the forecast is an established international greenhouse operator.

The high forecast was developed by including additional (lower probability) loads from projects requesting service via our interconnection process. The low forecast removes some projects from the mid load forecast and assumes service for cryptocurrency customers terminates before the end of the forecast period.

High and low cannabis and cryptocurrency load forecasts were developed and included in the high and low forecasts for the other large industrial sub-sector as inputs into the Monte Carlo uncertainty analysis. Table 8-3 shows the high, mid, and low forecasts before rate impacts.

Table 8-3 Cannabis and Cryptocurrency Mid, High and Low Forecast Before Rate Impacts

Fiscal year	High cannabis/cryptocurrency total incremental sales (GWh)[1]	Mid cannabis/cryptocurrency load additions total incremental sales (GWh)[1]	Low cannabis/cryptocurrency total incremental sales (GWh)[1]
F2018	N/A	N/A	N/A
F2019[2]	108	108	48
F2020	749	453	99
F2021	941	646	190
F2022	943	648	150
F2023	944	649	151
F2024	945	650	152
5 Yr. Forecast (F18 to F23)	N/A	N/A	N/A

Table notes:

1. N/A means that there were no customers classified as cannabis or cryptocurrency as part of our historical sales in fiscal 2018 or earlier. As such, the historical data to compute growth rate is not applicable.
2. Forecast for fiscal 2019 does not include any actuals.

9.0 Electric Vehicle Forecast

9.1 DESCRIPTION

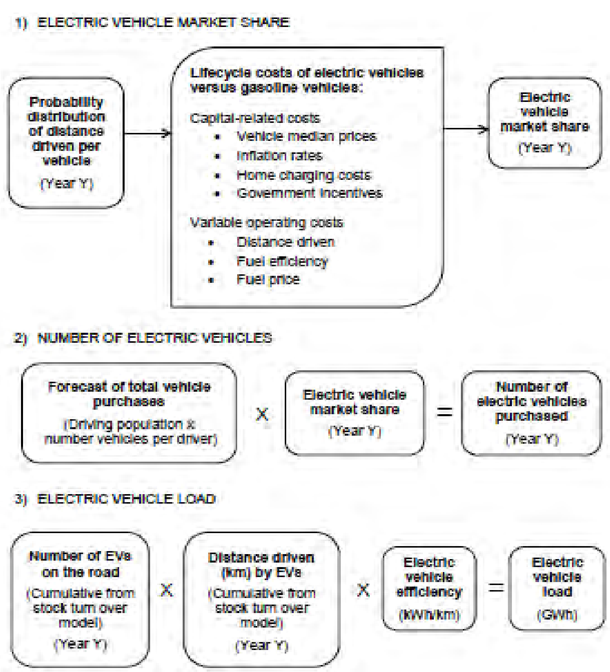
BC Hydro develops an electric vehicle (EV) load forecast to estimate electricity sales across our system due to growth in the total number of electric vehicles. The electric vehicle forecast is split amongst the residential sector and commercial sectors based on Insurance Corporation of British Columbia (ICBC) data on the number of light duty electric vehicles that are for personal and business use. As a result, 85 per cent of the total electric vehicle load forecast is allotted to the residential sector and 15 per cent is allotted to the commercial sector.

9.2 ELECTRIC VEHICLE METHODOLOGY

BC Hydro's electric vehicle load forecast is based on our in house electric vehicle stock turn over model (EV model). The EV model combines both types of EVs (battery plug-in vehicles and plug-in hybrid vehicles) rather than a separate model and a separate forecast for types of plug-in electric vehicles.

The EV model develops a forecast of the total stock of electric vehicles. Our EV model does distinguish between luxury EVs[34] and non-luxury EVs. A trend analysis is used to develop a forecast for the number of luxury EVs, where the trend analysis informs the load projection for these types of EVs. The load forecast for luxury EVs is added to the load forecast for the non-luxury EVs which is developed by the EV model discussed below. Figure 9-1 below illustrates the key inputs and calculations of our EV model (non-luxury vehicles).

Figure 9-1 Electric vehicle model



[34] Luxury EVs are not eligible for government incentives as such these are modelled and forecasted separately.

9.2.1 Computation of annual EV market share

The EV model starts with a forecast of the annual EV market share (ratio of the annual number of EVs to the annual number of vehicles). The key drivers for determining the market share include: (i) a distribution of the driving distance for all types of vehicles; and (ii) the costs of electric vehicles relative to gasoline vehicles which are broken down to fixed and variable costs. The fixed cost reflects the capital related costs of vehicles, which include median sales prices (for both EVs and gasoline vehicles), announced government incentives, and home charging costs for EVs. Variable costs reflect operating costs which are determined by the annual distance driven, fuel efficiencies, and electricity rates versus gasoline prices.

The EV model randomly selects an annual distance driven from an overall probability distribution of annual distance driven per vehicle (fitted to historical data). Next, the model computes the total cost as per the randomly selected annual distance driven and compares it to a break even cost as well the range constraint, which is the maximum annual distance driven or maximum range (in kilometers) for EVs. The break-even cost is the cost at which the model estimates an indifference to gasoline vehicles and EVs. The comparison analysis results in the initial annual EV market share.

The initial market share is adjusted over the near term of the forecast period to reflect an assumed gradual development of adoption of EVs. We assume electric vehicle adoption will grow gradually because of a number of factors such as gradual increases in consumer preference, vehicle range, infrastructure improvements, and EV model availability. However, the growth of EVs is likely to increase more rapidly than currently assumed as a result of government policies, such as those contained in the CleanBC plan, which are targeting greenhouse gas (GHG) emissions reductions. As mentioned in the introduction, the CleanBC Plan actions are not reflected in the October 2018 Load Forecast.

9.2.2 Computation of the total number of electric vehicles

The forecast of the annual total number of electric vehicles is determined by the product of the EV market share and the total vehicle purchase forecast. The total vehicle purchase forecast is determined by the product of the driving population forecast and an estimate of the number of vehicles per driver. The stock turn over portion of the EV model keeps track of the vehicle life expectancy and the annual distance driven of electric vehicles. As such, the year over year change in the total number of electric vehicles as shown in Table 9-1 below does not equal to the annual number of vehicles purchased.

9.2.3 Computation of electric vehicle load

Part three of Figure 9-1 illustrates the annual electric vehicle load in GWh resulting from a product of three variables which include the total number of electric vehicles, the annual distance driven per EV, and the average efficiency of electric vehicles.

9.2.4 October 2018 mid EV forecast model assumptions

The October 2018 mid EV forecast includes the following main assumptions:

- constant energy efficiency of 7.8 L per 100 km for gasoline vehicles and 0.20 KWh per km for EVs,
- existing government subsidies as of August 2018 are taken into account, but no new policies or initiatives are assumed,
- the same projection of electricity rates (i.e. future bill impacts) are used to develop the rate impacts for our October 2018 mid forecast with rate impacts before DSM,
- the average (mid) capital cost of EVs in real dollars is $37,657 and the average (mid) capital cost of gasoline vehicles in real dollars is $27,591. Each of which are assumed to increase at the rate of inflation,
- the average cost of installing an EV charging station which is assumed to be $2,000 as part of the fixed cost, and
- over the near term of the forecast period, the initial EV market share is adjusted to account for a gradual development of EVs in the market.

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9.3 ELECTRIC VEHICLE FORECAST RESULTS

Table 9-1 below shows the EV stock shares for the mid forecast and high forecast. The EV stock share is a ratio of the total number EVs to all vehicles.

The EV stock share for the high forecast is developed by assuming that EV incentives reflected in the mid case continue over the entire forecast period and a +/- 10 per cent variability around the mid capital cost of EVs, the mid capital cost of gasoline cars and mid forecast of gasoline prices.

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Table 9-1 EV Stock Share - Total Number of EVs as a Percentage of The Total Number of all Vehicles

Fiscal year	EV Stock Share Mid Forecast	EV Stock Share High Forecast
Actuals		
F2013	0.0%	0.0%
F2014	0.0%	0.0%
F2015	0.1%	0.1%
F2016	0.1%	0.1%
F2017	0.2%	0.2%
F2018	0.4%	0.4%
Forecast		
F2019[1]	0.6%	0.8%
F2020	0.8%	1.3%
F2021	1.0%	1.8%
F2022	1.4%	2.7%
F2023	2.0%	4.1%
F2024	2.9%	5.9%
5 Yr. Avg. Historical (F13 to F18)	54.3%	54.3%
5 Yr. Avg. Forecast (F18 to F23)	42.0%	63.2%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

Table 9-2 shows the mid forecast of EVs load before rate impacts as well as the EV load for each of the residential and commercial sectors. The table also shows the mid forecast for the total number of EVs and the total number of EVs for the high forecast and EV load for the high forecast.

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Table 9-2 EV Mid and High Forecasts Before Rate Impacts

Fiscal year	Mid EV Forecast				High EV Forecast	
	Residential EV Load Additions[1] GWh	Commercial EV Load Additions[1] GWh	Total EV Load Additions GWh	Mid Forecast Total Number of EVs (EV Stock)	High EV Load GWh	High Forecast Total Number of EVs (EV Stock)
Actual						
F2013	1.7	0.3	2	567	2	567
F2014	3	1	4	1,157	4	1,157
F2015	6	1	7	2,122	7	2,122
F2016	11	2	12	3,869	12	3,869
F2017	17	3	20	6,230	20	6,230
F2018	29	5	34	10,803	34	10,803
Forecast						
F2019[2]	48	8	56	18,053	78	26,231
F2020	66	12	77	24,299	118	40,602
F2021	89	16	105	32,553	165	57,697
F2022	124	22	146	45,080	249	88,091
F2023	187	33	220	67,402	380	135,452
F2024	277	49	326	99,651	558	199,259
5 Yr. Actual (F13 to F18)	76.1%	76.1%	76.1%	80.3%	76.1%	80.3%
5 Yr. Forecast (F18 to F23)	45.4%	45.4%	45.4%	44.2%	62.2%	65.8%

Table notes:

1. The allocation factors are 85 per cent for the residential and 15 per cent for commercial sector based EV data obtained from ICBC.
2. Forecast for fiscal 2019 does not include any actuals.

9.4 ELECTRIC VEHICLE UNCERTAINTIES

The EV load forecast results before rate impacts consist of a mid and high forecast. A mid forecast of the number of EVs and the annual electricity consumption of EVs is estimated using the EV model described above. The detailed assumptions used to develop the mid EV load forecast are outlined in Section 9.2.4 above.

The high EV load forecast comes from a separate Monte Carlo analysis built into our in house EV model. The EV Monte Carlo analysis includes assigning a distribution of outcomes for gasoline prices and capital costs of both types of vehicles. In addition, the analysis assumes that EV incentives known at the time of developing the October 2018 Load Forecast will continue over the forecast period. The Monte Carlo analysis produces a range of EV load forecasts. The p-90 EV load forecast outcome from this range is an input into the Monte Carlo uncertainty model as described in Section 11.2.2. Depending on the actual duration and dollar amount of government incentives, which may differ from our assumptions, this could alter the p-90 EV load forecast result. This uncertainty is not reflected in the overall Monte Carlo uncertainty model as the model is bound between the mid and high EV load forecast.

Given the significant growth potential in EVs, its associated growth drivers and historical sales growth pattern, we consider the mid load forecast to be a reasonable forecast of future EV load. Consequently, only the high forecasts generated from the EV model are reflected in the uncertainty bands.

10.0 Non-Integrated Areas and Other Utilities Forecast

This section is divided into two main parts: (i) Non–Integrated Areas and (ii) sales from BC Hydro to other utilities. We begin with describing the Non-Integrated Area sales followed by sales to other utilities. In both sections we describe the methodology and then the forecasts results.

10.1 NON-INTEGRATED AREAS (NIA)

10.1.1 NIA description

The non-integrated areas consist of a number of small communities located in parts of B.C. not connected to BC Hydro's integrated transmission grid. The communities of our Non Integrated Areas (NIA) include:

- Customers in the Purchase Areas in the South Interior. The Purchase Areas consists of the following six locations: Lardeau, Shutty Bench, Crowsnest, Newgate, Kingsgate-Yahk, and Kelly Lake. To serve customers in the Purchase Areas, BC Hydro purchases electricity from a number of neighbouring electric utilities,
- Customers in Zone II communities in the North Region and Vancouver Island. Zone II non-integrated area customers include 15 communities from the following locations[35]: Masset, Sandspit, Atlin, Dease Lake, Telegraph Creek, Anahim Lake, Bella Coola, Hartley Bay, Good Hope Lake, Toad River, Jade City, Fort Ware, Kwdacha, and Tsay Keh Dene,
- Customers in Zone 1B community of Bella Bella in the North Region, and
- Customers in the Northern Rockies Regional Municipality (Fort Nelson area) in the North Region.

As of fiscal 2018, total gross requirements for the entire NIA were 315 GWh, where more than half of this amount is in the Fort Nelson area.

10.1.2 NIA forecast methodology

Various methodologies are used to develop the forecast for communities that make up the NIA areas. The methodologies range from trend analysis, developing specific customer load forecasts, and regression models. All of the forecasts developed from these methods are supplemented with information from local community members about future loads. BC Hydro's Distribution Area Planners, which look after planning distribution station assets within the NIA areas, gather information from local connection offices and communities about load increase or decrease for all NIA areas.

For the Purchase Areas, the forecast is developed by a trend analysis of the historical total gross requirements of the communities that makes up the Purchase Areas.

For Zone II and Zone 1B communities, the forecasts are developed using a trend analysis of the historical loads that make up major sectors in these areas. A trend analysis is carried out for the residential sector, commercial and light industrial sector and other loads such as street light customers, irrigation customers and BC Hydro own use. The trend analysis establishes a base load forecast which is supplemented by other forecast information on individual projects or customers loads. This additional load information is obtained from customer service requests via local BC Hydro personal or identified by our Distribution Area Planners. These load additions tend to be the main drivers of load growth within all of these communities.

[35] In Table 10.1, loads for the community of Eddontenajon are not included because this community is connected to our integrated transmission grid.

For Fort Nelson area sales, the forecast is developed as the sum of the forecast for each of the major customer sectors including residential, commercial and light industrial and a large industrial sector, which consists of two major loads which are derived as follows:

- The forecast for the residential sector is the product of the accounts and the average use per account. The account projection and the average use per account projection are based on a trend analysis of historical billing data. A trend analysis is used because there is not enough resolution (i.e. detail in our residential end use survey) to develop a statistically sound SAE model for the residential and commercial load in communities that make up the NIA areas.
- The forecast for the commercial and light industrial sector is developed with a regression model involving historical sales and employment where the history and forecast of employment comes from Conference Board of Canada June 2018 Economic Forecast. The forecast for the wood product segment which consists of two mills, currently shutdown, is developed on an account by account basis.
- The forecast for the two large industrial customers in the Fort Nelson area are also developed on an account by account basis using the same methodology that applies to other oil and gas loads connected to the integrated grid.
- The forecasts for street lighting customers, irrigation customers and BC Hydro own use within the Fort Nelson area is developed based on a trend analysis.

The Non-Integrated Area Load Forecast is the result of an aggregation of our load forecasting analysis (i.e., trends, customer projections, and regression models, and load additions as requests for service) for all parts of the NIA listed above, less load reductions for rate impacts and load reductions for savings from our DSM plan.

Rate impacts are developed in the same manner as they are developed for the main customer sectors described in this Report. Savings from our DSM plan identified for the NIA area are allocated to each of the four main parts that make up the NIA on an historical sales percentage basis. An allocation of the DSM savings is used because it is not exactly known which individual part of the NIA will engage in demand side management activities.

10.1.3 NIA forecast results

The Non-Integrated Area Load Forecast results are shown in Table 10-1.

Table 10-1 NIA Total Gross Requirements Sales History and Forecast After Rate Impacts and After DSM

Fiscal year	Purchase area Load Forecast (GWh)	Zone II and Zone 1B Load Forecast (GWh)	Fort Nelson Load Forecast (GWh)	Total NIA Load Forecast (GWh)
Actual				
F2013	12	116	202	329
F2014	12	115	202	330
F2015	12	112	205	329
F2016	11	114	202	324
F2017	13	114	201	326
F2018	14	115	185	315
Forecast				
F2019[1]	14	115	192	322
F2020	15	119	194	328
F2021	15	120	195	329
F2022	15	120	230	365
F2023	15	120	231	366
F2024	15	120	231	366
Growth rates				
5 Yr. Actual (F13 to F18)	4.0%	-0.1%	-1.7%	-0.9%
5 Yr. Forecast (F18 to F23)	1.0%	0.9%	4.5%	3.1%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

For the most part, the loads that make up the NIA are stable and the forecasts indicate a slow increase much like the historical trend. The largest growth is anticipated to occur in the Fort Nelson area over the period of fiscal 2021 to fiscal 2022. During this period it is expected that there will be an increase in the demand for electricity by the wood product segment.

10.1.4 NIA uncertainties

The main risks to the NIA forecast are discrete events such as the opening or closing of operations. In some instances, the exact timing of when these projects are expected to transpire are difficult to predict as major developments, such as large residential or commercial projects, within the smaller communities often require external funding. Our BC Hydro planners, NIA station managers and other personal with BC Hydro keep in contact with various communities to gather information on the types of future loads and when future loads are expected come on line.

Some of the loads in the Fort Nelson area are dependent upon the future development of the resource sector. These loads can vary from the forecast due to changes in external market conditions such as fluctuations in natural gas prices and wood segment prices.

10.2 OTHER UTILITIES

The other utilities served by BC Hydro are listed below:

- City of New Westminster, located within BC Hydro's Lower Mainland Region,
- FortisBC Electric, located in southeastern B.C.,
- Seattle City Light, located in the state of Washington, USA, and
- Hyder, Alaska, located in Alaska, USA.

Hyder is served at distribution voltage while the other three utilities are served at transmission voltage.

All of these utilities have formal arrangements with BC Hydro for electrical service. In fiscal 2018, annual energy sales to City of New Westminster, FortisBC Electric, Seattle City Light, and Hyder were 465 GWh, 551 GWh, 312 GWh, and 1 GWh, respectively. Firm exports include Seattle City Light and Hyder, while sales to inter-utilities include City of New Westminster and FortisBC Electric.

10.2.1 Other utilities forecast methodology

The forecast methodology varies by utility, as follows:

- The forecast for the City of New Westminster is based on trend analysis and information from BC Hydro's distribution planners on new larger projects that have requested electricity service.
- The forecast of sales to FortisBC Electric is based on a modelled comparison of the relative cost of purchasing electricity from BC Hydro (including future rate increases) applied to Rate Schedule 3808 versus the cost of market purchases. The model also considers information provided by FortisBC Electric on their expected purchase of electricity from BC Hydro. Since the forecasting model determines the forecast of sales to FortisBC Electric by the relative costs of purchases (i.e., market vs BC Hydro rates) it already accounts for the impact future changes in our electricity rates. As such, there is no need to apply a further rate impact to the results of the model.
- The forecast for Seattle City Light is prescribed within a treaty between British Columbia and Seattle dated March 30, 1984 and which expires on January 1, 2066.
- The sales forecast for Hyder, Alaska is based on a trend analysis.

10.2.2 Other utilities load forecast results and risks

Table 10-2 shows the other utilities' forecast with rate impacts.

Table 10-2 Other Utilities Sales History and Forecast After Rate Impacts

Fiscal year	City of New Westminster (GWh)	FortisBC Electric (GWh)	Seattle City Light (GWh)	Hyder, Alaska (GWh)	Total other utilities (GWh)
Actual					
F2013	455	340	310	1.1	1,106
F2014	457	492	308	1.0	1,258
F2015	444	522	305	0.9	1,272
F2016	455	516	308	0.9	1,280
F2017	463	588	318	0.9	1,370
F2018	465	551	312	0.8	1,330
Forecast					
F2019[1]	469	492	310	1.0	1,272
F2020	470	542	310	1.0	1,323
F2021	471	555	310	1.0	1,337
F2022	474	582	312	1.0	1,369
F2023	476	599	310	1.0	1,386
F2024	479	592	310	1.0	1,382
Growth Rates					
5 Yr. Actual (F13 to F18)	0.4%	10.1%	0.1%	-6.2%	3.8%
5 Yr. Forecast (F18 to F23)	0.5%	1.7%	-0.1%	4.5%	0.8%

Table notes:

1. Excluding the forecast for FortisBC Electric, the forecasts for fiscal 2019 for other utilities does not include any actuals.

Electricity sales to the City of New Westminster are forecast to grow about 0.5 per cent over the next five years, which is keeping in line with historical sales growth. Sales to FortisBC Electric are forecast at an annual compound growth rate of 1.7 per cent over the next five years. Both Seattle City Light and Hyder are forecast to have no significant growth.

10.2.3 Other utilities uncertainties

The main risk to the forecast of electricity sales to the City of New Westminster is a discrete event such as a further large new load addition. The risks to the forecast of sales to FortisBC Electric would be unforeseen changes in the market conditions which may impact how that utility plans to meet its supply arrangements.

Given that the forecast for Seattle City Light is based on a signed treaty, there is minimal sales risk over the entire forecast period. The sales risk for Hyder is also minimal given that its load is so small.

11.0 Monte Carlo Methods and the High and Low Uncertainty Bands

11.1 INTRODUCTION

Load forecasting involves a considerable amount of uncertainty. The demand for electricity depends on a large number of factors which can fluctuate relative to expected outcomes. Some of these factors include: the economy, weather, technology, electricity rates, and changes in the way electricity is consumed. Monte Carlo simulation is our approach to demonstrating uncertainty. This section describes how the Monte Carlo uncertainty model is used to develop the uncertainty bands around our mid total forecast after rate impacts. High and low uncertainty bands are the simulated outcomes of our Monte Carlo uncertainty model, which includes uncertainty variables, statistical distributions, mathematical models, impact factors and a method of random simulation.

11.2 MONTE CARLO METHODS AND SIMULATION PROCESS

Our Monte Carlo uncertainty model contains the following elements:

Uncertainty Variables

A main feature of the model is the inclusion of uncertainty variables. These are:

- economic growth (measured by real provincial GDP growth),
- electricity rates (expressed as real dollar bill impacts),
- temperature (measured by heating degree days),
- economic elasticities (elasticity of load with respect to real provincial GDP); and
- electricity price elasticities of demand.

In addition to these major uncertainty drivers, we also include high and low large industrial forecasts for each sub-sector. The high and low forecasts account for the diversity and uncertainty within this sector. Also included in the model is a range for electric vehicle load and a range for adjustments to codes and standards.

Probability Distributions

- The other feature of the model includes probability distributions which are assigned to the uncertainty variables. This assignment enables a statistical range to be established around the mid forecast of the uncertainty variables.

Impact Factors

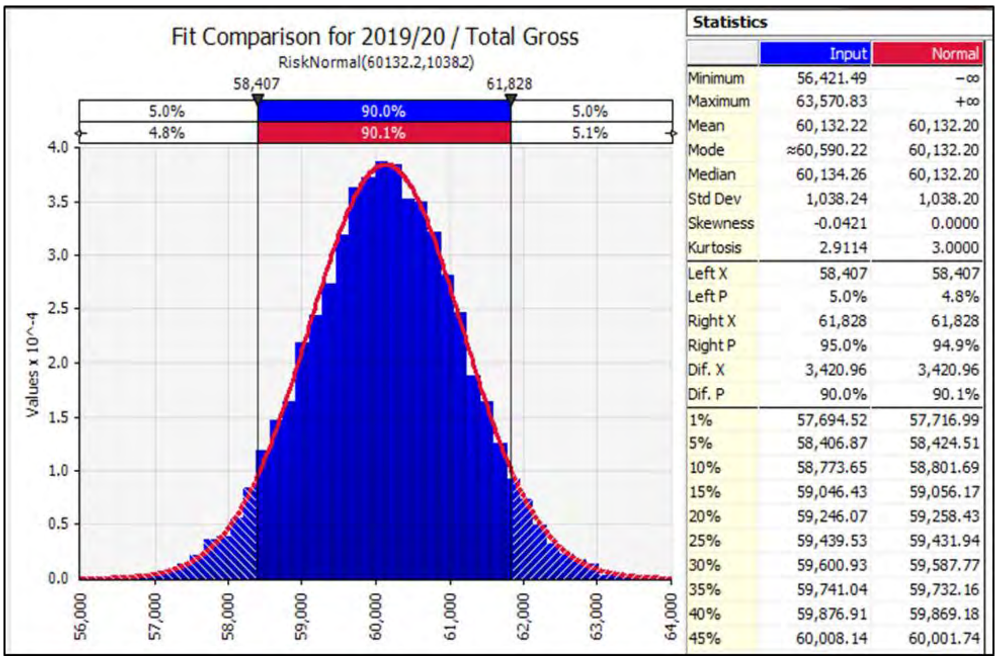
- In addition to probability distributions, there are impact factors which are random variables that perturb (i.e., alter through simulation) the mid load forecasts for residential sector, combined light industrial and commercial sectors, and the large industrial sub-sectors. The sectors which make up about two-thirds of the total area sales (i.e., residential, and commercial and light industrial) have their own impact factors.
- For the remaining one-third of our total area load, the large industrial sector, the range of load outcomes is determined by a different mathematical model. This model uses another set of random impact factors that apply to each of the four main industrial sub-sectors including, mining (metal and coal), forestry (pulp and paper, wood and chemical), oil and gas (shale gas and other large oil and gas operations) and the other large industrial customers. We also include transmission service-connected cannabis and cryptocurrency loads. These are included with all the customers that make the other large industrial sub-sector. The models

are connected through a correlation matrix that consists of correlations between GDP growth and the entire range of load for the large industrial sub-sectors.

Simulation Process and Output

- To calculate its outputs, the model undergoes a simulation (Monte Carlo) process by randomly sampling the probability distributions. The outcome of this process is a range of load outcomes in the form of a probability distribution for each customer sector, total firm sales, and the total system and total integrated system gross requirements. The Monte Carlo simulation process is run 5,000 times for each year of the forecast. Mathematically, with a large number of random simulations, this process results in a symmetric distribution. An example of the model's output for a given year is shown in Figure 11-1.

Figure 11-1 Symmetrical distribution output of our Monte Carlo Uncertainty Model



11.2.1 Large industrial impact factors

The impact factors and the equation that results in the ranges of load outcomes for the large industrial sector is expressed by the following equation:

Equation 11.1a

$$E_t = {}_0E_t I_t^P I_t^S$$

The parts of this equation are explained below.

The term I_t^p in equation above applies to each of the four main large industrial sub-sectors. Where p standards for the forecast of real electricity rates (i.e., real dollar bill impacts). The term I_t^S is the impact factor that applies to the large industrial sub-sectors and transmission service-connected and cannabis and cryptocurrency loads.

The equation for I_t^S is as follows:

Equation 11.1b

$$I_t^S = {}_0E_t^S + \left({}_0E_t^S - E_t^S \right)$$

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In equation 11.1b, the superscript S represents each of the large industrial sub-sectors, ${}_0E_t^S$ is the mid electricity sales forecast before rate impacts for those sub-sectors, and E_t^S represents a randomly selected forecast from a triangular distribution of the mid forecast before rates for each sub-sector. See section 11.3.8 below for the high and low forecasts for each sub-sector that bound the triangular distributions for each large industrial sub-sector.

11.2.2 Residential and light industrial and commercial impact factors

The impact factors that results in the range of load outcomes for the residential and combined commercial/light industrial sectors is expressed by the following equation:

Equation 11.1c

$$E_t = 0E_t I_t^P I_t^G I_t^W$$

In the above formula E_t is the electricity sales outcome, $0E_t$ is the mid electricity sales forecast with rate impacts for the sector (i.e. residential or commercial/light industrial). P stands for the mid real electricity price forecast (i.e. real dollar bill impacts), G stands for the mid real provincial GDP growth forecast, and W stands for temperature expressed as heating degree days. Rates, economy, and temperature are the main uncertainty drivers contained in the impact factors. However, the Monte Carlo uncertainty model also accounts for uncertainty for economic elasticity, EV load, and adjustments for codes and standards as described below.

11.2.3 Economic uncertainty

Impact of economic uncertainty (i.e., real GDP growth): This applies to the residential sector and combined commercial / light industrial sectors. In order to assess the impact of economic uncertainty on the loads, the forecast of real provincial GDP growth that is used in our mid load forecast is perturbed randomly through a series of equations as shown by equations 11.2b to 11.2c. The mid GDP growth is denoted by ${}_0g_t$ and the perturbed GDP is denoted byG_t. The perturbed GDP starts off being equal to the mid GDP growth in the first year. It then grows at a growth rate equal to the mid GDP growth rate (${}_0g_t$) plus a random perturbation growth rate (g_t). This random perturbation is a normally distributed random variable with zero mean and a standard deviation of 1.70 per cent, which is denoted as the equation below:

Equation 11.2a

$$g_t \sim N(0, 1.70\%)$$

The perturbed mid GDP is calculated by:

Equation 11.2b

$$G_t = G_{t-1}\left[1 + {}_0g_t + g_t\right]$$

The impact factor for GDP is then given by the following equation.

Equation 11.2c

$$I_t^G = exp\left(\propto ln\left({G_t}/{{}_0G_t}\right)\right) = \left({G_t}/{{}_0G_t}\right)^\alpha$$

Where α is the elasticity of load with respect to mid GDP growth.

11.2.4 Impact of economic uncertainty reflects updated economic elasticities

Table 11-1 shows the mid and a range of economic elasticities as well as the distributions around the economic elasticities used in the Monte Carlo uncertainty model for the residential and combined commercial / light industrial sectors. The residential sector economic elasticity is the elasticity of use per account to real disposable income. The economic elasticity for the commercial sector is the elasticity of commercial sales to real commercial GDP.

These mid economic elasticities for residential sector are developed based on a regional sales weighted average of the economic elasticities included in our SAE models. The mid commercial elasticity is developed in the same way. Information on the economic elasticities contained in our residential and commercial SAE models is found in Appendix C. The high and low ranges of elasticities are also based on the economic elasticities in our SAE models, where the low value is the minimum elasticity and the high is the maximum. The economic elasticities are not specific to GDP but are consistent to the new updated elasticities between load variables and other economic variables that are correlated with GDP.

Table 11-1 Economic Elasticity included in Monte Carlo Uncertainty Model

Sector	Probability Distribution (low, mid, high)
Residential	Triangular (0.19, 0.19, 0.27)
Light industrial/Commercial	Triangular (0.10, 0.21, 0.24)

11.2.5 Electricity rate uncertainty

Impact of Electricity Rate Uncertainty: This applies to all customer sectors. The calculation of the impact factor for electricity rates (I^P_t) is similar to the impact factor of GDP described above. As such, there are two variables that determine the uncertainty of load with respect to electricity rates. The first variable is the mid projection of real electricity rates which is represented as projections of real dollar bill impacts and the second variable is electricity price elasticity of demand. For the October 2018 Load Forecast, the result of the Monte Carlo model in the tables below do not reflect variability around the projection of future electricity rates. This is because the bill impact projections reflected in the October 2018 Load Forecast are based the last five years of the 2013 10-Year Rates Plan as described in our F2017 to F2019 Revenue Requirements Application.

11.2.6 Temperature uncertainty

Impact of Temperature Uncertainty: This source of uncertainty applies to the residential sector and to a lesser extent the commercial/light industrial sector. In British Columbia, the impact of colder weather and temperatures on the residential sector results in additional heating load during the winter months. As such, customer response to colder temperatures (i.e., heating sensitivity) is modelled with a range of heating degree days (HDD)[36] and elasticities of load to heating degree days.

The range of heating degree days is determined from the annual sales weighted total heating degree days over the last 10 years ending fiscal 2018. To develop the range we first constructed a monthly sales weighted (i.e., a sales weighting of the monthly heating degree days across our four services regions) heating degree day variable from actual monthly heating over the past 10 years. Next, from the monthly data series, we found the annual sales weighted total heating degree days over past 10 years and calculated the mean over the same period, which is 1,022 heating degree days.

[36] Heating degree days are calculated for every day. The number of heating degree days in one region such as the Lower Mainland is calculated by the formula: $HDD = max(0, Daily\ Temperature - 15)$. Then, the annual sum of HDD is calculated for each year.

To determine the uncertainty of temperature on the load, a normal probability distribution is used in combination with a temperature impact factor which perturbs the residential and light industrial / commercial mid forecast. The temperature impact factor is shown below in equation 12.3a.

Equation 12.3a

$$I_t^w = exp\left\{\varepsilon_w \, log\left({}^{HDD_t}/_{1,022}\right)\right\}$$

In the equation above ε_w is the elasticity of annual residential sales with respect to annual heating degree days. The value ε_w is estimated to be 0.20 for the residential sector and 0.05 for combined commercial/light industrial sectors. HDD_t in the equation above represents the historical annual sales weighted total HDD over the past 10 years. The probability distribution that is fitted to the historical annual sales weighted total HDDs over the past years is a truncated normal distribution with the parameters shown in Table 11.2 below.

Table 11-2 Temperature Distribution Parameters

Sector	Probability Distribution of HDD (min, mean, max)
Residential	Truncated Normal (831, 1,022, 1,219)
Light Industrial / Commercial	Truncated Normal (831, 1,022, 1,219)

The temperature impact factor does not cause the high and low band to increase over the forecast period because the impact of variability of temperature on the load in a year does not impact the loads in the future years. As such, the impact of temperature is independent amongst all the years over the forecast period. This property is different to the GDP and electricity rate impact factors which have year to year cumulative effects over the forecast period.

11.2.7 EV and overlap in codes and standards uncertainty

Impact of EVs and Overlap in Codes and Standards: The Monte Carlo uncertainty model also considers the uncertainty of EV load and uncertainty in adjustments for overlap in codes and standards. This is accomplished by establishing distributions for each of EV load and adjustment in codes and standards. For EVs uncertainty, a log normal distribution is fitted around the mid and high EV load forecast. There is a triangular distribution around the load additions for overlap in codes and standards included in our mid load forecast. The distribution is +/- 50 per cent of the load additions for overlap in codes and standards in our mid forecast.

11.2.8 High and low large industrial sub-sector forecast

Table 11-3 below contains the low, mid, and high large industrial sub-sector forecasts before rate impacts. These forecasts are inputs to the Monte Carlo uncertainty model and were developed as per the assumptions described in Section 7.

Table 11-3 Large Industrial Sub-Sector Mid High and Low Forecasts Before Rate Impacts Included in the Monte Carlo Uncertainty Model

Fiscal year	Sub-sector	Low Mid High Large Industrial Sales (GWh)

		Low	Mid	High
F2019[1]	Mining	3,804	3,827	3,853
	Forestry	6,424	6,656	6,817
	Oil and Gas	2,065	2,332	2,475
	Other Large Industrial	1,183	1,253	1,275
F2020	Mining	3,621	3,985	4,012
	Forestry	6,028	6,751	7,403
	Oil and Gas	2,382	2,770	3,055
	Other Large Industrial	1,227	1,632	1,979
F2021	Mining	2,839	4,068	4,499
	Forestry	5,407	6,058	7,489
	Oil and Gas	2,583	2,998	3,233
	Other Large Industrial	1,311	1,856	2,231
F2022	Mining	2,582	4,051	4,723
	Forestry	4,760	5,677	7,242
	Oil and Gas	2,673	3,301	3,729
	Other Large Industrial	1,272	1,874	2,248
F2023	Mining	2,582	4,020	5,343
	Forestry	4,650	5,596	7,172
	Oil and Gas	2,804	3,753	5,385
	Other Large Industrial	1,273	1,882	2,256
F2024	Mining	2,340	3,939	5,937
	Forestry	4,634	5,669	7,179

Table notes:

	Oil and Gas	3,272	4,845	6,664
	Other Large Industrial	1,274	1,896	2,270

1. Forecast for fiscal 2019 does not include any actuals.

11.2.9 Correlations included in the Monte Carlo uncertainty model

The uncertainty model contains a correlation matrix between the large industrial sub-sectors and GDP growth that gets applied to the residential and combined commercial/light industrial sectors. The correlation matrix ensures that if a series of high draws for the large industrial sub-sector occurs in any single simulation then a high draw of a random GDP disturbance term occurs with a certain probability. This brings together the element of correlation between high and low large industrial load with a high and low residential and combined commercial/light industrial loads. In addition to this correlation matrix, the Monte Carlo uncertainty model contains a correlation matrix between oil and gas and LNG loads. This is included because development of the LNG industry can impact the oil and gas industry and subsequent load growth in this sub-sector.

11.3 MONTE CARLO RESULTS FOR OCTOBER 2018 LOAD FORECAST

The output of the Monte Carlo uncertainty model provides a range of forecasts around the mid forecast after rate impacts. We demonstrate this range by showing high and low bands which are the p-10 and p-90 outcomes from model. The high and low bands are summarized in the following tables[37]

- Table 11-4 contains the low, mid and high band for the total gross system requirements forecast after rate impacts before DSM savings.
- Table 11-5 contains the low, mid and high forecast of total Firm sales after rates before DSM savings, and
- Table 11-6 contains the low, mid and high Total Domestic Load Forecast after rates and DSM savings. The high and low forecasts in Table 11-6 are determined by a post-processing of the high and low bands of total firm sales contained in Table 11-5. This post-processing involves reducing the high and low bands of total firm sales by the mid forecast of BC Hydro own use and the mid forecast of DSM savings.

Table 11-4 Low, Mid and High Total System Gross Requirements After Rate Impacts Before DSM savings

Fiscal year	October 2018 Low Total Gross Requirements GWh	October 2018 Mid Total Gross Requirements GWh	October 2018 High Total Gross Requirements GWh
Actual			
F2013	56,584	56,584	56,584
F2014	57,712	57,712	57,712
F2015	55,807	55,807	55,807

[37] The tables in this section show the history and forecast on a billed basis.

F2016	56,525	56,525	56,525
F2017	56,893	56,893	56,893
F2018	57,842	57,842	57,842
Forecast			
F2019[1]	57,494	58,472	59,465
F2020	58,844	60,299	61,772
F2021	58,551	60,630	62,760
F2022	58,517	60,997	63,538
F2023	58,647	61,684	64,814
F2024	59,586	63,216	66,956
5 Yr. Actual (F13 to F18)	0.4%	0.4%	0.4%
5 Yr. Forecast (F18 to F23)	0.43%	1.43%	2.43%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

Table 11-5 Low, Mid and High Total Firm Sales After Rate Impacts

Fiscal year	October 2018 Low Total Firm Sales GWh	October 2018 Mid Total Frim Sales GWh	October 2018 High Total Firm Sales GWh
Actual			
F2013	51,135	51,135	51,135
F2014	52,164	52,164	52,164
F2015	51,520	51,520	51,520
F2016	51,075	51,075	51,075
F2017	51,693	51,693	51,693

F2018	52,275	52,275	52,275
Forecast			
F2019[1]	52,239	53,127	54,030
F2020	53,488	54,810	56,150
F2021	53,207	55,096	57,032
F2022	53,170	55,426	57,732
F2023	53,294	56,055	58,899
F2024	54,173	57,473	60,873
5 Yr. Actual (F13 to F18)	0.4%	0.4%	0.4%
5 Yr. Forecast (F18 to F23)	0.4%	1.4%	2.4%

Table notes:

1. Forecast for fiscal 2019 in the table above do not include any actuals.

Table 11-6 Low, Mid and High Total Domestic Load After DSM Savings

Fiscal year	October 2018 Low Total Domestic Sales GWh	October 2018 Mid Total Domestic Sales GWh	October 2018 High Total Domestic Sales GWh
Actual			
F2013	51,062	51,062	51,062
F2014	52,088	52,088	52,088
F2015	51,448	51,448	51,448
F2016	51,005	51,005	51,005
F2017	51,623	51,623	51,623
F2018	52,202	52,202	52,202

Forecast			
F2019[1]	51,708	52,594	53,495
F2020	52,243	53,561	54,897
F2021	51,370	53,253	55,182
F2022	50,842	53,090	55,388
F2023	50,679	53,434	56,272
F2024	51,257	54,552	57,948
5 Yr. Actual (F13 to F18)	0.4%	0.4%	0.4%
5 Yr. Forecast (F19 to F23)	-0.6%	0.5%	1.5%

Table notes:

1. Forecast for fiscal 2019 does not include any actuals.

11.3.1 Monte Carlo model simulation produces separate load results

The high and low uncertainty bands for above loads segments (i.e. total gross requirements and total frim sales) should be viewed as a separate set of outcomes from the random simulation process. The random simulation process produces an outcome distribution around the mid forecasts with rate impacts each of the main customer sectors (i.e. residential, combined commercial / light industrial and large industrial), total firm sales, and total integrated and gross requirements. Since the Monte Carlo simulation process is random and involves multiple simulations, the combination of uncertainty variables that makes up the low and high bands for any particular customer sector is not the same combination of the uncertainty variables that makes up the low and high band for total firm sales or total system gross requirements.

12.0 Overlap in Codes and Standards

12.1 DESCRIPTION

Codes and standards are minimum end-use efficiency requirements that come into effect in a jurisdiction, and that are enabled by legislation or by regulation of manufacturers. U.S. based codes and standards are reflected in the average stock efficiency forecast of residential and commercial end uses of electricity. The average stock efficiency forecasts are produced by the U.S.EIA. The EIA efficiency forecast is one of the main inputs of the residential and commercial SAE models and the forecasts from these models are the starting point for the load forecasts for these sectors.

BC Hydro's DSM plan also includes savings that can be achieved from B.C. and Canadian Federal codes and standards that target similar end uses as those represented in the EIA efficiency forecast data. As such, there is a potential for overlap in efficiency requirements for end uses of electricity that are enabled from codes and standards as modelled by EIA assumptions and our DSM plan.

12.2 AREAS OF OVERLAP IN CODES AND STANDARDS BETWEEN EIA AND OUR DSM

The EIA assumes that no new legislation or regulations fostering efficiency improvements beyond those currently embodied in law or government programs will take place over the forecast horizon. These efficiency level assumptions are documented by the EIA in the annual energy outlook. BC Hydro has reviewed the EIA's documentation on minimum efficiency standards on end use of electricity and technologies and compared those to the efficiency standards of end use electricity and technologies, contained in our DSM plan, that are enabled by B.C and Canadian Federal codes and standards. Using this information, BC Hydro was able to determine where there were overlaps in codes and standards on various residential and commercial end uses of electricity and technologies. Table 12-1 below shows some of the end uses and technologies where there was an overlap in codes and standards.

Table 12-1 Examples of Overlap in Codes and Standards

Sector	Examples of Areas of Overlap between EIA Codes and Standards and BC Hydro DSM Plan
Residential Sector	Lighting, dishwashers, stand-by power, TVs, freezers, refrigerators and clothes washers
Commercial Sector	Lighting, large clothes washers, walk in coolers, large refrigerators, air conditioning, packaged terminal air conditioning, and dry transformers.

12.3 ESTIMATES OF OVERLAP BETWEEN EIA CODES AND STANDARDS AND CODES AND STANDARDS IN OUR DSM PLAN

After the areas where overlap or double counting in codes and standards are determined, an adjustment is made to our SAE model projections to account for the overlap in codes and standards. We adjust the SAE models' projections to mitigate potential double counting by using an estimate of the overlap between EIA assumptions reflected in our models and codes and standards that result in electricity savings which are contained in our DSM plan.

Previous forecasts (those prior to October 2018) also reflected load adjustments for overlap in codes and standards. Load adjustments for overlap in codes and standards, including lighting, has been in place since our 2010 Load Forecast. In that forecast, we responded to BCUC directive number 6 as per its Decision on BC Hydro's 2008 Long Term Action Plan (LTAP).That directive required BC Hydro to review the potential for double counting DSM and address it in its next LTAP. The review we completed resulted in applying load adjustments to SAE model projections, where these load adjustments accounted for areas where there was overlap in codes and standards.

For the non-lighting code items that were considered to be an overlap, BC Hydro applied 50 per cent of the forecast of DSM savings of these various codes and standards which overlapped with the EIA. These estimates were then used as the adjustments to the SAE model projections.

The 50 per cent assumption is a high level estimate because there are a number of uncertainties we were not able to address as part of our evaluation. These uncertainties include the following:

- There are differences in timing between our service area relative to the geographic areas incorporated in the EIA model (Pacific region) on when the various code and standards come into place,
- There are differences in end uses and technology modelled in the DSM plan and those modelled in the EIA. For example, in the area of refrigeration, not all of the same types of refrigerators are modelled from the same starting point on efficiency and types of various refrigerators. There may also be differences in compliance rates between our service area relative to what is assumed in the EIA model,
- The EIA model only includes the impacts of past U.S, legislation and regulations and does not include future codes and standards. Our DSM plan includes savings from future regulations that are planned and announced, and
- Using the savings from the DSM plan as the basis to determine the impact of the overlap of codes and standards on our load forecast is at best a proxy estimate.

For lighting codes and standards, where there is also double counting for various lighting technologies (i.e. different types of a light bulbs), we have left the base year (i.e. 2018) efficiency level of indoor and outdoor lighting as provided by the EIA unchanged over the forecast period. This method for lighting was chosen to provide consistency with previous forecasts that had already identified a double counting issue with lighting codes and standards.

We continue to assess the extent of the overlap over the various diverse set of electrical appliances and uses of electricity as part of our continuous improvement efforts. Further work in this area may lead to revised overlap projections.

13.0 Glossary

Accrued Sales are an estimate of electricity delivered within a specific month. Most customer meters are not read at every month-end, so the amount of electricity delivered in a month is not known precisely. In accordance with GAAP, monthly accrued sales are used for monthly financial reporting.

Back-casting Estimating econometric or other models over a historical time period and comparing the predictions of the models to actual results over the same time period.

Billed Sales The amount of electricity billed. Because bills are produced after the electricity has been delivered, monthly billed sales lag monthly delivery of electricity.

Binary Variable is a variable whose value is either zero or one. Binary variables are often used as independent variables in regression models in order to account for events that either occur or do not occur. In this latter context, binary variables are often referred to as "dummy variables" in regression.

Calibration Estimating econometric or other models over a historical time period.

Coincidence Factor A ratio reflecting the relative magnitude of a region's (or customer's or group of customers') demand at the time of the system's maximum peak demand to the region's (or customer's or group of customers') maximum peak demand.

Commercial Output Commercial output focuses on the provisions of services in the economy and so includes such things as public administration, insurance agents, bankers, wholesale and retail trade, food services, accommodation provisions etc.

Consumer Price Index (CPI) An inflation index calculated by comparing the price of a typical bundle of goods in the year in question to the price of the same goods in a set reference year.

Cooling Degree Day (CDD) is a measure of warmness, defined by the number of degrees above a certain daily average temperature measured in Degrees Celsius CDDs are drivers of utility air-conditioning electricity loads.

Demand-Side Management (DSM) Activities that occur on the demand side of the revenue meter and are influenced by the utility. DSM activities result in a change in electricity sales. Past DSM savings include incremental load displacement and energy efficiency savings. Note that BC Hydro's historical sales include the impact of DSM savings realized up to that year.

Design Temperature Rolling average of the coldest daily average temperature over the most recent 30 years

Distribution Voltage Customer A BC Hydro customer who receives electricity via distribution lines that operates at lower voltages (60 kV and less).

Domestic System Peak includes the peak requirements for BC Hydro's distribution and transmission customers in its service territory; sales to the City of New Westminster and system transmission and distribution losses.

Econometric Modelling The use of statistical techniques, typically regression analysis of time-series and/or cross-sectional data, to detect statistically verifiable relationships, coherent with economic theory, between an explained variable (e.g. electricity consumption) and explanatory variables (e.g. industry output, prices of alternative energy inputs and GDP).

Elasticity The proportionate change in a dependent variable (e.g. electricity consumption) divided by the proportionate change in a specified independent variable (e.g. electricity price). A dependent variable is highly elastic with respect to a given independent variable if the calculated elasticity is much greater than one. The dependent variable is inelastic if the elasticity is less than one.

End-use Model A model used to analyze and forecast energy demand, which focuses on the end uses or services provided by energy. Typical end uses are lighting, process heat and motor drive. For a given industry, the model estimates the influence of prices and technological change on the evolution of the secondary energy inputs required to satisfy the industry's end uses over time.

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Energy The amount of electricity delivered or consumed over a certain time period, measured in multiples of watt-hours. A 100-watt bulb consumes 200 watt-hours in two hours.

Energy Efficiency Is the ratio of the energy service delivered from a process or piece of equipment to the energy input. Energy efficiency is a dimensionless number, with a value between 0 and 1 or, when multiplied by 100, is given as a percentage.

EV Electric Vehicle

Fuel Switching is specific to the October 2018 forecast as presented in this report. Fuel switching means switching from one kind of energy source or use to another that decreases GHG emissions in B.C., and the estimated fuel switching load included in the October 2018 forecast is based on specific government or BC Hydro programs that incent customers to switch from fossil fuel-based energy to clean electricity.

GAAP Generally Accepted Accounting Principles

Gigawatt-hour (GWh) A measure of electrical energy, equivalent to one million kilowatt-hours. (See Units of Measure)

Gross Domestic Product (GDP) A measure of the total flow of goods and services produced by the economy over a specified time period, normally a year or quarter. It is obtained by valuing outputs of goods and services at market prices (alternatively at factor cost), and then aggregating the total of all goods and services.

Heating Degree Day (HDD) Is a measure of coldness, defined by the number of degrees below a certain daily average temperature measured in Degrees Celsius. HDDs are drivers of utility space heating electricity loads.

Integrated System That portion of the BC Hydro's electricity system which is connected as one whole by a high voltage transmission grid.

Integrated System Peak includes the peak requirements for BC Hydro's distribution and transmission customers in its service territory; sales to Other Utilities, which includes Seattle City Light, New Westminster, FortisBC and Hyder Alaska (Tongass Power and Light Co. Inc.); and system transmission and distribution losses.

Intensity A unitized measure of energy consumption, typically in kilowatt-hours per unit of stock. For example, intensity is kWh per account in the residential sector or kWh per unit of production in the industrial sector.

Kilowatt (kW) A kW is 1000 watts and a watt is measure of power that can be transferred instantaneously

Kilowatt-hour (kWh) A measure of electrical energy over a period of time, equivalent to the energy consumed by a 100-watt bulb in 10 hours. (See Units of Measure)

Liquefied Natural Gas (LNG) is natural gas that has been converted temporarily to liquid form for ease of storage or transport. This process involves refrigeration, and requires no chemical transformations.

Load The total amount of electrical power demanded by the utility's customers at any given time, typically measured in megawatts.

Load Displacement Projects that involve the installation of self-generation facilities at customer sites, with the electricity generated being used on-site by the customer, with a resultant decrease in the purchase of electricity from BC Hydro.

Megawatt (MW) A unit used to measure the capacity or potential to generate or consume electricity. One MW equals one million watts. (See Units of Measure)

Megawatt-hour (MWh) A measure of electrical energy, equivalent to 1,000 kWh. (See Units of Measure)

Monte Carlo Method A technique for estimating probabilities involving the construction of a model and the simulation of the outcome of an activity a large number of times. Random sampling techniques are used to generate a range of outcomes. Probabilities are estimated from an analysis of this range of outcomes.

Megavolt-Amps (MVA) – a unit of apparent power, which is real power in MW, divided by power factor.

Natural conservation The increase in energy efficiency that would occur in the absence of any utility-induced demand-side management program, all other things being equal.

Non-coincident In general is the magnitude of a region's (or customer's or group of customers') demand at the time of its peak.

Non-Integrated Area (NIA) Non-integrated facilities refer to generating facilities that are not connected to the system, located in remote areas of the province

Normalization The correction of actual customer sales and peak demand for factors such as unusually warm or cold weather.

Ordinary Least Squares (OLS) is a method of estimating parameters to minimize the sum of squares errors in a regression model.

Price Elasticity of Demand The percentage change in quantity demanded, divided by the percentage change in price that caused the change in quantity demanded.

Real Price Increases that have been adjusted for changes in prices of all goods. The nominal price of an item may rise by 10 per cent over a year, but inflation (and assumed wages) may have risen by 7% over the same time period. Therefore the effective price increase faced by the consumer is close to 3 per cent. It is necessary to deflate current prices by an appropriate inflation index (the CPI in Canada) to convert money values to constant prices or real terms.

Region A geographical sub-division of the BC Hydro service area used for Load Forecast purposes. Four regions exist: Lower Mainland, Vancouver Island, South Interior and the Northern Region.

Stock A quantity representing a number of energy consuming units. For example, in the residential sector, stock is the number of accounts or housing units; in the commercial sector, stock is represented by the floor area of commercial building space.

System Coincident Peak Demand The greatest combined demand of all BC Hydro customers faced by the generation system during a given fiscal year.

Transmission Voltage Customer A BC Hydro customer that is supplied its electricity via high-voltage transmission lines (60 kV or above).

Trinary variable is another type of binary variable that accounts for instances where sales or use per account in one moth is observed to be shifted from one month to the other.

Units of Measure The large amounts of electricity generated and consumed on a system-wide basis are discussed in multiples of the basic units of watt and watt-hours. Kilowatts and megawatts are used to measure power, and kilowatt-hours, megawatt-hours, and gigawatt-hours are used to measure energy. The equivalence is:

1 kilowatt (kW)	= 1,000 watts
1 megawatt (MW)	= 1,000 kilowatts or 1 million watts
1 kilowatt-hour (kWh)	= 1,000 watt-hours
1 megawatt-hour (MWh)	= 1,000 kilowatt-hours or 1 million watt-hours
1 gigawatt-hour (GWh)	= 1,000 megawatt-hours or 1 billion watt-hours

14.0 Overview of Appendices

The Appendices cover five elements of the October 2018 Load Forecast:

A. **October 2018 vs. May 2016 Load Forecast:** this Appendix contains a table showing a comparison between the October 2018 Load Forecast and the May 2016 Load Forecast after DSM and Loss Reductions savings.

B. **SAE Equations and Forecasting Models:** this Appendix provides an explanation of the general framework and equations of the SAE model.

C. **SAE Model Improvements:** this Appendix includes an explanation on the revised economic elasticities and the revised heating and cooling variables incorporated into the 2018 SAE models.

D. **October 2018 SAE Models:** this Appendix contains the regression results and statistical data from the October 2018 residential and commercial SAE models.

E. **Temperature Normalization and Residential Accounts Forecasts Improvements:** this Appendix includes: (i) a description of our temperature normalization process for the residential and commercial sectors; and (ii) a comparison between the results of previously issued residential accounts forecasts and revised forecasts with our new methodology.

F. **Economic Forecast and Other Drivers:** we provide a list of the economic forecast and sources that were used to develop the October 2018 residential (unadjusted), commercial (unadjusted) and light industrial unadjusted) forecasts. We also include the EIA 2018 average efficiency forecast used to develop the residential and commercial forecasts.

G. **October 2018 Load Forecast Tables:** contains a series of tables showing the October 2018 forecast before rate impacts, after rate impacts and after DSM savings and loss reductions.

15.0 Appendix A: October 2018 vs May 2016 Load Forecasts

15.1 COMPARISON OF TOTAL LOAD AFTER DSM SAVINGS

Table 15-1 below compares the mid October 2018 Load Forecast and mid May 2016 Load Forecast of the total (Domestic) Load after DSM savings and loss reductions.

Over the same time period (i.e., fiscal 2018 to fiscal 2023) the October 2018 Load Forecast is expected to grow more slowly compared to the May 2016 Load Forecast. This is because of changes (updates) in various factors that impact load growth in the residential and commercial sectors which make up two thirds of the total load as well changes in the LNG load forecast.

The lower October 2018 Load Forecast for the residential and commercial sectors reflects several factors. These factors include the updated (last 10 years ending fiscal 2018) calibration period, an updated (slower growing) forecast of economic drivers, the recalibration of relationships between economic variables and sales (lower economic elasticities) and the updated (mainly higher) projection of average efficiency various end uses of electricity. These changes which have resulted in lower residential and commercial sector forecasts do not offset the increases in revised forecasts for the oil and gas sub-sector and the light industrial sector. The October 2018 Load Forecast for the light industrial sector is higher over the entire forecast period relative to forecast contained in the May 2016 Load Forecast due to incremental load from the emerging cannabis and cryptocurrency industries. The October 2018 Load Forecast for the oil and gas sub-sector is higher compared to the May 2016 forecast due to expected growth in the shale gas sector.

As for the change in the LNG load forecast, which accounts for most of the difference between the two forecasts by the end of the forecast period, the updated (October 2018) LNG load forecast for LNG terminals is lower relative to the May 2016 forecast due to:

- a revised methodology for developing the forecast for LNG terminals, and
- a change in the timing and the expected load for LNG terminals.

Table 15-1 Comparison of Total Domestic Load After DSM Savings

Fiscal year	October 2018 Load Forecast (GWh)[1]	May 2016 Load Forecast (GWh)[1]	October 2018 Forecast minus May 2016 Load Forecast (GWh)	Difference to the May 2016 Load Forecast (per cent)
Actual (temperature normalized)				
F2013	51,107	51,108		
F2014	51,957	51,958		
F2015	52,283	52,284		
F2016	51,724	52,071[2]	(347)	-0.7%
F2017	51,597	51,858[2]	(261)	-0.5%
F2018	52,024	51,823[2]	201	0.4%
Forecast				
F2019	52,594[3]	52,652	(58)	-0.1%
F2020	53,562	53,025	537	1.0%
F2021	53,252	54,337	(1,085)	-2.0%
F2022	53,088	56,100	(3,012)	-5.4%
F2023	53,433	57,164	(3,731)	-6.5%
F2024	54,553	58,052	(3,499)	-6.0%
5 Yr. Avg. Historical (F13 to F18)	0.4%	0.3%		
5 Yr. Avg. Forecast (F18 to F23)	0.5%	2.0%		

Table notes:

1. Domestic sales include loads for our main customer sectors, irrigation customers, street light customers, sales to inter-utilities and frim exports supplied by BC Hydro. Both load forecasts in the table above include load reductions for DSM savings and loss reductions savings.
2. Indicates that the value is based on the May 2016 Load Forecast.
3. Indicates the load forecast does not include any actuals for the current fiscal year (i.e., fiscal 2019).

16.0 Appendix B: SAE Equations and Forecasting Models

16.1 INTRODUCTION

Our unadjusted sales forecasts[38] for residential and commercial sectors are based on:

- the estimated coefficients of the SAE, and
- the forecasts of economic data, temperature data, average efficiency data and saturation data. All of these are included in the SAE models.

Section A1.2 below covers the general framework of the SAE model, the development of its main variables (i.e., Heating, Cooling and Other) and the equations for these variables.

16.2 STATISTICALLY ADJUSTED END USE FRAMEWORK

The description of the SAE framework described below for the residential sector generally applies to the commercial sector. The main difference between the residential and commercial framework is that the dependent variable in the residential framework is the average use per account and the dependent variable in commercial framework is commercial sales.

The statistically adjusted end-use modeling framework begins by defining the dependent variable: the average electricity use per account (Use_m) in a month (m) as the sum of the average electricity use by per account from heating equipment ($Heat_m$), cooling equipment ($Cool_m$), and other equipment ($Other_m$). Formally, this is written as:

Equation B.1

$$USE_m = Heat_m + Cool_m + Other_m$$

Equation B.1 can be written in the format of a linear regression model as:

Equation B.2

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m$$

Where: USE_m is the dependent variable of the above regression model or average use per account (monthly). The independent variables in the regression model are $XHeat_m$, $XCool_m$, and $XOther_m$. These are the main explanatory variables, which are constructed monthly (m) from end-use information, economic drivers, and temperature data. The parameter ε_m represents the random error term in the above regression model. The parameters b_1, b_2, and b_3 are the coefficients of the regression model which represent the relative contribution of the main explanatory variables (i.e., major end uses) to the average residential use per account.

The equations below show the construction of the main independent variables. For each variable there is data in the historical period (i.e., estimation period) and data in the forecast period. The estimated coefficients of the model and the forecast data for each main variable determine the results (i.e., forecast of average use per account) that come from the SAE model.

XHeat: represents average heating use per account. The amount of electricity used per account for heating depends on the following types of variables:

[38] In this Appendix as well all of the other sections and appendices contained in this report, the term “unadjusted forecast” and the “term model projections” are used interchangeably.

- heating degree days (temperature),
- heating equipment saturation levels (percentage of accounts that have a certain type of heating equipment),
- average efficiency of heating equipment,
- average number of days in the billing cycle for each month, and
- economic variables. For the residential sector this includes people per account and real personal disposable income. For the commercial sector this includes employment, real retail sales, and real commercial GDP.

The heating variable $XHeat_m$ is a product of a monthly equipment index and a monthly usage multiplier. In equation form this is expressed as:

Equation B.3

$$XHeat_m = HeatIndex_m \times HeatUse_m$$

Where: $\mathrm{XHeat_m}$ is the average heating use per account in a month (m). This variable is a product of two monthly index variables: (i) $\mathrm{HeatIndex_m}$ is the aggregate amount of heating use per account in a month for the various types of heating equipment; and (ii) $\mathrm{HeatUse_m}$ is monthly index of heating usage.

The sub-equation for $HeatIndex_m$ in equation B.3 is:

Equation B.3.1

$$HeatIndex_m = \sum_{SpaceHeating} EndUseEnergy_{e,BaseYear} \times \frac{\left({}^{Share_m}/_{Eff_m} \right)}{\left({}^{Share_{BaseYear}}/_{Eff_{BaseYear}} \right)}$$

Where: End Use Energy is the average use per account for each type of heating equipment, e refers to the different categories of space heating, BaseYear represents the base year for the SAE model, Share mean saturation levels[39] of the different types of heating equipment which comes from our Residential End Use Survey data (REUS), Eff is the average efficiency of the different types of space heating equipment.

The heating equipment index (i.e., HeatIndex) depends on heating equipment saturation levels normalized (i.e., divided) by average efficiency level. As a result, the heating index will increase over time if there are changes in heating equipment saturation levels, and will decrease over time if there are improvements in the average equipment efficiencies or the thermal efficiency of residences.

Space heating usage level (i.e., $XHeatUse_m$) is a function of temperature (Heating Degree Days) and economic factors. The sub-equation for $XHeatUse_m$ in equation B.3 is:

Equation B.3.2

$$HeatUse_m = \left[\frac{BDays_m}{30.5}\right] \times \left[\frac{WgtHDD_m}{HDD_{BaseYear}}\right] \times \left[\frac{PeoplePerAccount_m}{PeoplePerAccount_{BaseYear}}\right]^{EI1} \times \left[\frac{Income_m}{Income_{BaseYear}}\right]^{EI2}$$

Where: m refers to monthly values, Base Year is the base year of the SAE model, BDays refers to billing days and *EI1 and EI2* are the economic elasticities of average use per account for people per account and real disposable income respectively. Each annual economic variable is converted into a monthly indices which is developed as a 12 month rolling average of the annual economic variable weighted (i.e., divided) by its average monthly value in the base year of the model. The variable $WgtHDD_m$ is the actual weighted heating degree days in a month divided by the average monthly heating degree days in the base year of the model. The weights applied to the monthly heating degree days are used to align the actual monthly heating degree days to the billing cycle data on

[39] Saturation levels are defined as the percentage of accounts that have a certain type of electrical equipment or appliance.

the residential sales over the year. For the forecast period, the variable $WgtHDD_m$ is the 10 year rolling average (i.e., temperature normalized) of heating degree days in each month.

XCool: represents the average cooling use per account. This variable is constructed in a similar manner to heating. The amount of electricity use per account for cooling depends on the following types of variables:

- cooling degree days (temperature variable),
- cooling equipment saturation levels (percentages of residential accounts that have a cooling appliance),
- average efficiency of cooling equipment,
- average number of days in the billing cycle for each month, and
- economic variables including people per account and disposable income.

The cooling variable, $XCool_m$, is represented as the product of an equipment-based index and monthly usage multiplier. In equation form this represented as:

Equation B.4

$$XCool_m = CoolIndex_m \times CoolUse_m$$

Where: $XCool_m$ is the average electricity use per account for cooling in a month (m), $CoolIndex_m$ is an index of average cooling equipment use per account in a month (m); and $CoolUse_m$ is the monthly usage multiplier for cooling.

The sub-equations for $CoolIndex_m$ and $CoolUse_m$ are the same equations as those above for heating (i.e., equations B.3.1 and B.3.2) with the exception the last equation B.3.2 includes cooling degree days instead of heating degree days.

As with space heating, the cooling equipment index ($CoolIndex_m$) depends on the cooling equipment saturation levels normalized (i.e., divided) by average efficiency levels. As a result, the cooling index will increase over time if there are changes in cooling equipment saturation levels, and will decrease over time if there are improvements in equipment efficiencies or the thermal efficiency of buildings. Space cooling system usage levels ($CoolUse_m$) are driven on a monthly basis by several factors, including temperature (Cooling Degree Days) and similar economic factors used to develop heating usage.

XOther: represents the average use per account for residential end-uses of electricity that are not temperature sensitive. Some examples of non-temperature sensitive end-uses are lighting, refrigeration, cooking, clothes washing and drying, entertainment equipment (TVs) and other plug in equipment. The average use per account of electricity for other equipment is driven by:

- appliance and equipment saturation levels,
- appliance efficiency levels,
- average number of days in the billing cycle for each month, and
- economic variables.

The explanatory variable $XOther_m$ is defined as:

Equation B.5

$$XOther_m = OtherEqpIndex_m \times OtherUse_m$$

The first term on the right hand side (i.e., $OtherEqpIndex_m$) of the above equation embodies information about the average usage per month of various non-temperature dependent appliances as well as their saturation levels and their average efficiency ratings. The second term ($OtherUse_m$) captures the impact of economic variables of the overall average use of electricity through the use of other non-temperature dependent equipment. These economic variables are the same ones used for explaining heating and cooling use.

The first term has the following sub-equation:

Equation B.5.1

$$Other\ Eqp\ Index_m = Weight^{Type} \times \frac{Sat_m^{Type} / Eff_m}{Sat_m^{Type} / Eff_m} \times MoMult_m^{Type}$$

The weight term is the non-temperature dependent average use per account for specific residential end uses of electricity such as lighting, dishwasher, refrigerators etc. Sat_m^{Type} is the saturation level (i.e., percentage of accounts having at least one of these types of end uses). *Eff* is the average stock efficiency from the EIA of the various non–heating and non-cooling end uses. *MoMult* is a monthly multiplier that shapes the index to our billing data on the average use per account.

The equation for second term on the right hand side of equation B.5 above can be expressed as:

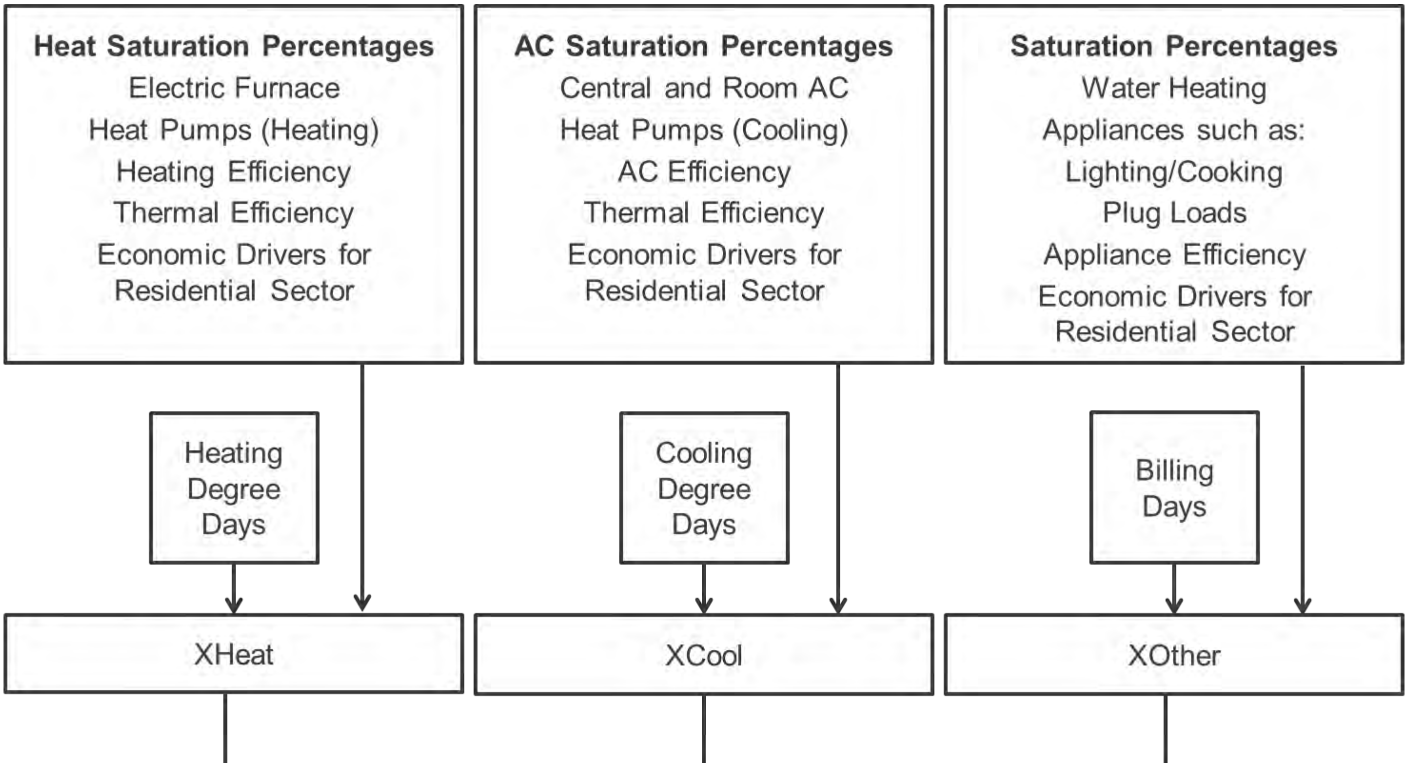
Equation B.5.2

$$Other\ Use_m = \left[\frac{BDays_m}{30.5}\right] \times \left[\frac{PeoplePerAccount}{PeoplePerAccount}\right]^{EI1} \times \left[\frac{Income_m}{Income}\right]^{EI2}$$

Where: $BDays_m$is billing days and *EI1* and EI2 are the economic elasticities of average use per account for people per account and real disposable income respectively.

In summary, Figure 16-1 below shows the inputs used in the construction of the regression variables (i.e. the independent variables) for the residential SAE models. As mentioned above the residential SAE model dependent variable is the average use per account and the commercial SAE model dependent variable is commercial electricity sales. The residential and commercial SAE models also differ in inputs in terms of economic variables, elasticities, and the regional temperatures that determine heating and cooling degree days. The latter of these two variables are discussed in Appendix C below.

Figure 16-1 Statistically Adjusted End Use (SAE) Model



$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m$$

17.0 Appendix C: SAE Model Improvements

17.1 SAE ELASTICITY PARAMETERS

As mentioned in Section 3.2.5 of this report, we have updated the economic elasticity parameters used in our residential and commercial statistically adjusted end use models. The elasticities in the context of the SAE model framework are intended to represent the percentage change in use per account or sales due to a one percentage change in any specific economic driver.

To update these economic elasticities for our SAE models we developed a series of linear regression models and from these results we computed elasticities. For example, to determine the elasticity of sales to employment for the commercial SAE models we developed linear regression model such as:

Equation C.1a

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + b_4 \times Employment_m + b_5 \times Accounts_m + \varepsilon_m$$

Where: USE_m is monthly electricity sales for the Lower Mainland commercial general over 35 kw segment, employment is a 12 month moving average of employment created from annual employment data from the Conference Board of Canada, June 2018 Economic Forecast, accounts is the monthly number of commercial general over 35 kW accounts, b_1 to b_5 are the coefficients of the model and ε_m is the error term.

The *XHeat* variable in the above regression model contains the $\mathrm{HeatIndex}_m$ as described in equation B.3.1 above and the temperature portion of $\mathrm{HeatUse}_{\mathbf{m}}$ as described in equation B.3.2 above. This means that *XHeat* reflects the average weighted saturation and efficiency portion and the temperature portion of the two indices that make up the *XHeat* variable. All of the main variables (i.e., *XHeat*, *XCool*, *XOther*) in the regression model above are constructed in a similar manner (i.e., they excluded the economic variable in the index driver) so that separate elasticities could be computed from the regression results. In this example, the elasticity of commercial Lower Mainland over 35 kW sales to employment is determined from the estimated coefficients of the regression model above and the following equation:

Equation C.1b

$$Elasticity\ of\ Sales\ to\ Employment = b_4 \times \frac{Mean\ Value\ of\ Employment}{Mean\ Value\ of\ Sales}$$

Where: b_4 is the estimated coefficient from the model above (i.e., C.1a) which is multiplied against the ratio of the mean value of employment and the mean value of commercial sales where the means are computed from historical data used in the calibration (i.e., estimation) period.

17.2 SAE ELASTICITY RESULTS

For the residential and commercial sectors, linear regression models, such as the one shown in equation C.1a above, were estimated with data using the last 10 years ending fiscal 2018. For the residential sector we considered the economic variables of people per account and real disposable income and the average use per account as the dependent variable. The economic variables for the commercial sector included employment, real retail sales and real commercial GDP.

We developed regression models with different combinations of economic variables and other independent variables such as the number of commercial accounts. This exercise produced many regression models (i.e. over 100), which we then assessed to determine the elasticities for the economic drivers for each sector on a regional basis. All of economic data, on a regional basis, came from the Conference Board of Canada, June 2018 Economic Forecast.

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Tables 17-1 and 17-2 below contain the update economic elasticities for the residential and commercial sectors compared to the elasticities used in the May 2016 Load forecast. These elasticities are lower than those used in the May 2016 Load Forecast, for which we explain below for the commercial sector.

Over the estimation period, we experienced slower growth in commercial sales and use per account relative to growth in the economic drivers. For example, Figure 17-1 below show actual year over year growth in commercial sales for the BC Hydro service area and the year over year growth in employment and real commercial GDP over for the BC Hydro service area over the past 10 years. The figure clearly shows a weaker linkage between growth in sales and economic drivers. Given this, our updated economic elasticities are smaller relative to that those previously reflected in the other forecasts such as the May 2016 forecast.

Figure 17-1 Year over Year Growth in Commercial Sales and Economic Drivers

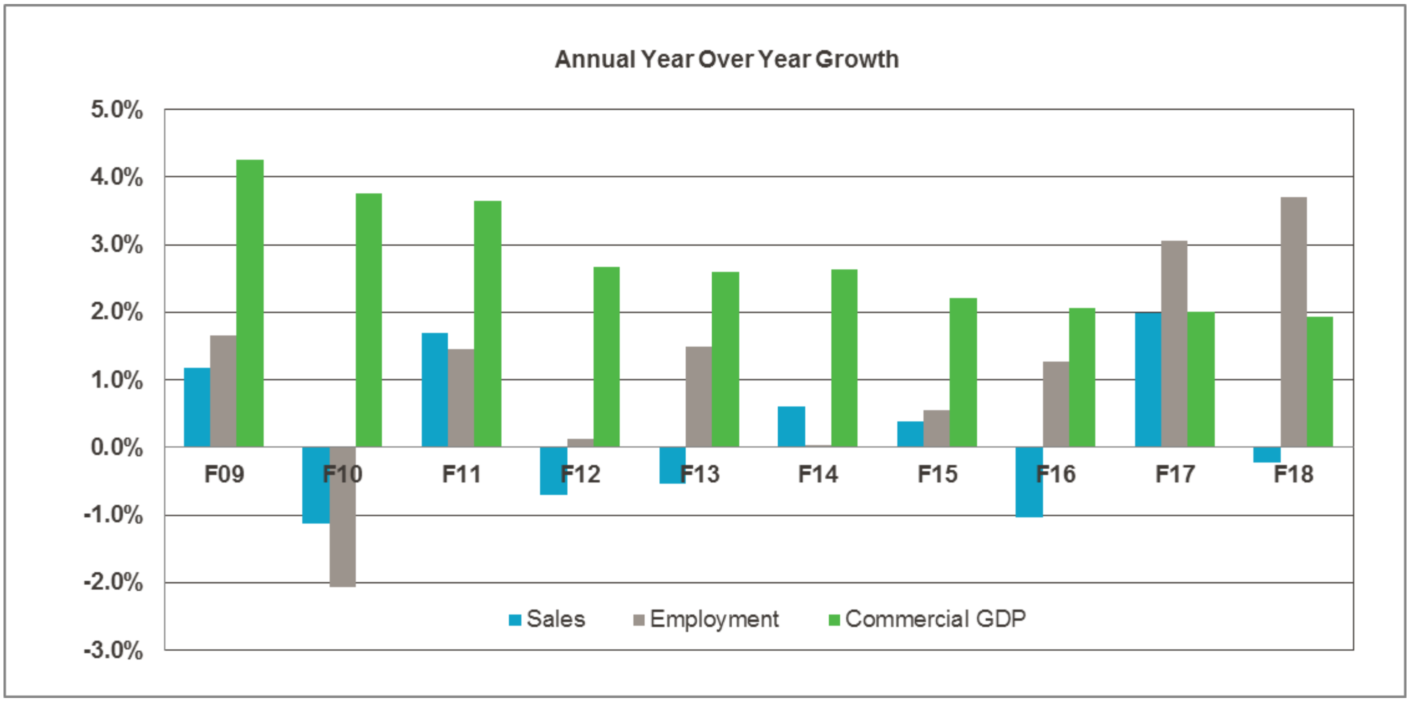

Table 17-1 Residential Elasticities October 2018 Load Forecast and May 2016 Load Forecast

Region	Used for October 2018' Load Forecast Real Disposable Income	Used for May 2016' Load Forecast Real Disposable Income	Used for October 2018' Load Forecast People per Account	Used for May 2016' Load Forecast People per Account
LM	0.27	0.20	0.38	0.25
VI	0.19	0.20	0.33	0.25
SR	NA	0.20	0.28	0.25
NR	NA	0.20	0.54	0.25

NA means were not able to find a statistically significant value

Table 17-2 Commercial Elasticities October 2018 Load Forecast and May 2016 Load Forecast

	Commercial Sector - Elasticities Used for October 2018 Load Forecast				Commercial Sector - Elasticities Used for October May 2016 Load Forecast		
Commercial Segment	Employment	Real Retail Sales	Real Commercial GDP	Commercial Segment	Employment	Real Retail Sales	Real Commercial GDP
LM<35	0.1	NA	Na	LM<35	1.1	0.7	0.5
LM>35	0.2	0.10	0.10	LM>35	1.1	0.7	0.5
VI<35	0.4	0.13	0.24	VI<35	1.4	0.6	0.6
VI>35	0.2	0.14	0.21	VI>35	1.2	0.7	0.4
South<35	0.7	NA	Na	South<35	1.5	0.9	0.6
South>35	0.4	0.3	0.2	South>35	1.6	1.1	0.6
North<35	0.5	Na	Na	North<35	0.5	0.3	0.2
North>35	0.4	0.2	0.1	North>35	0.5	0.3	0.2

NA means were not able to find a statistically significant value

17.3 SAE TEMPERATURE VARIABLES

As mentioned in Section 3.2.4 of this report, we have updated the temperature variables (i.e., heating and cooling degree days) used in in our October 2018 residential and commercial SAE models. The key work in this area was to determine the temperature where we see a customer response to decreasing temperatures (i.e., heating) and increasing temperatures (i.e., cooling). The daily average temperature at which we see increases in electricity sales or use per account to heating and cooling temperatures is known as the cut point temperature. The cut point temperature determines a heating or cooling degree day. A heating or cooling degree day which is calculated for each day in the year is determined as the difference between the daily average temperature on that day and the cut point temperature.[40] In the May 2016 Load Forecast the cut point temperature was 18 Degrees Celsius for all four regions within our service area. As such, the daily and monthly (i.e., total number of degree days in a month) heating and cooling degree variables were calculated as the difference between this cut point temperature and dry bulb daily average temperatures from data at four representative weather stations[41].

For the October 2018 Load Forecast, we updated the cut point temperatures for all four regions that make up our residential sector. We also updated the cut point temperature for our commercial sector on a regional basis. This results in eight different cut point temperatures (i.e., one for each commercial load segments that make up our commercial sector). The cut point temperature analysis was based on using load shapes for various load segments. The load shape data comes from our in-house load shape model that uses our smart metering infrastructure (SMI) data to develop historical load shapes by region and by customer segments for the residential and commercial sectors. We used load shape data from fiscal 2017 and fiscal 2014 as both of these years had several periods of cold and warm temperatures which we believe would be indicative of customer response to heating and cooling degree days.

Tables 17-3 and 17-4 below summarize the updated heating and cooling cut point temperatures for the residential and commercial sectors on a regional basis.

[40] As an example, heating degree day = maximum of (18°C – daily average temperature, zero). In this example 18°C is the cut point temperature.

[41] The four weather stations are located at YVR, or Vancouver International Airport for the Lower Mainland, Victoria International Airport for Vancouver Island, and Kelowna Airport represents the South Interior and Prince George Airport represents the North Region. Dry bulb means precipitation impact on daily average temperature is not included.

Table 17-3 Residential Cut Point Temperatures used for October 2018 Load Forecast

Region			Region		
Lower Mainland			South Interior		
		Cut Point			Cut Point
		Temperature			Temperature
	Variable	°C		Variable	°C
	CDD	17		CDD	21
	HDD	15		CDD	18
	HDD	3		HDD	13
	HDD	0		HDD	3
				HDD	-3
Region			Region		
Vancouver Island			North Region		
		Cut Point			Cut Point
		Temperature			Temperature
	Variable	°C		Variable	°C
	CDD	18		CDD	15
	HDD	15		HDD	12
	HDD	9		HDD	15
	HDD	3		HDD	9
	HDD	0		HDD	6

Table 17-4 Commercial Cut Point Temperatures used for October 2018 Load Forecast

Region			Region			Region			Region		
Lower Mainland < 35 kW			Vancouver Island < 35 kW			South Interior < 35 kW			North Region < 35 kW		
		Cut Point			Cut Point			Cut Point			Cut Point
		Temperature			Temperature			Temperature			Temperature
	Variable	°C		Variable	°C		Variable	°C		Variable	°C
	CDD	15		CDD	15		CDD	21		CDD	15
	HDD	12		HDD	15		CDD	17		HDD	9
	HDD	3		HDD	12		HDD	12		HDD	3
				HDD	6		HDD	6		HDD	-3
							HDD	-3		HDD	-9
							HDD	-9		HDD	-18
Region			Region			Region			Region		
Lower Mainland > 35 kW			Vancouver Island > 35 kW			South Interior > 35 kW			North Region > 35 kW		
		Cut Point			Cut Point			Cut Point			Cut Point
		Temperature			Temperature			Temperature			Temperature
	Variable	°C		Variable	°C		Variable	°C		Variable	°C
	CDD	15		CDD	15		CDD	15		CDD	9
	HDD	12		HDD	15		HDD	9		HDD	12
	HDD	3		HDD	9		HDD	-3			
							HDD	-9			

18.0 Appendix D: October 2018 SAE Models

Tables 18-1 to 18-12 below show the statistical estimation results of the October 2018 residential and commercial SAE models. Each SAE model produces the following statistical outputs which are used to assess the statistical robustness of model results:

- Estimated coefficient of the independent variable and standard error of the estimate,
- A t-test statistic on the statistical significance of the independent variable,
- P-value indicating the statistical significance of the independent variable. P-values greater than 5 per cent indicate that the variable is not statistically significant from zero,
- R-square statistic, R-squared adjusted statistic- which is adjusted for the number of variables. These statistics indicate the goodness of fit of the models over the calibration (estimation) period,
- Mean Absolute Percentage Error is a measure of the prediction accuracy of the model to predict over the calibration period, and
- The Durbin Watson statistics test for auto-correlation.[42] The Durbin Watson statistics are compared to values that come from the Durbin Watson significance tables to assess whether or not the estimated errors from the regression model have auto-correlation.[43]

All models are estimated with monthly billed sales or monthly average billed sales per account over the last 10 years ending fiscal 2018 (i.e., 120 data points), unless the model is corrected for auto-correlation then it is estimated with less data points. Each model is estimated with the method of Ordinary Least Squares estimation.[44]

Binary variables included in our SAE models take on the value of 1 or 0. For example, a Binary Variable for a specific month means 1 for that month otherwise 0. Trinary variable is another type of variable that accounts for instances where sales or use per account in one moth is observed to be shifted from one month to the other.

[42] A linear regression model that has auto-correlated errors means that the estimated error term in one period is correlated with an estimated error term in a previous period. The implication is that regression model is not statistically robust and R-square statistics and the t-test statistics are not reliable because the error terms are correlated.

[43] Durbin Watson significance tables can be found at https://www3.nd.edu/~wevans1/econ30331/Durbin_Watson_tables.pdf

[44] A description of ordinary least squares estimation can be found at: https://en.wikipedia.org/wiki/Ordinary_least_squares

Table 18-1 Residential SAE Model – Lower Mainland

Lower Mainland Residential SAE Model					
Variable	Coefficient	Standard Error	T-Statistics	P-Value	
Constant	795.8	71.4	11.1	0.00%	
XHeat	3.8	0.1	27.5	0.00%	
XCool	0.2	0.1	2.6	1.00%	
XOther	(0.6)	0.2	-2.8	0.56%	
Binary Variable 2016	142.3	36.6	3.9	0.02%	
Binary Variable 2015	88.6	26.0	3.4	0.09%	
Binary Variable 2014	64.2	22.1	2.9	0.44%	
Binary Variable 2013	103.2	21.7	4.8	0.00%	
Binary Variable 2012	87.7	21.7	4.0	0.01%	
Binary Variable 2011	125.4	18.8	6.7	0.00%	
Binary Variable 2010	108.0	14.2	7.6	0.00%	
Binary Variable 2009	115.5	14.4	8.0	0.00%	
Binary Variable 2008	92.7	18.7	5.0	0.00%	
Model Fit					
R-Squared		0.96			
Adjusted R-Squared		0.95			
Mean Absoulte Per cent Error (MAPE)		3.21%			
Statistic for Auto-correlation					
Durbin Watson Statistics		1.60			

Table 18-2 Residential SAE Model – Vancouver Island

Vancouver Island Residential SAE Model					
Variable	Coefficient	Standard Error	T-Statistics	P-Value	
Constant	1,103.2	121.4	9.1	0.00%	
XHeat	8.3	0.2	44.2	0.00%	
XCool	0.1	0.1	1.0	30.58%	
XOther	(1.1)	0.3	-3.8	0.03%	
Binary Variable 2016	163.1	41.6	3.9	0.02%	
Binary Variable 2015	142.6	41.4	3.4	0.08%	
Binary Variable 2014	(78.3)	41.5	-1.9	6.15%	
Binary Variable 2013	114.0	34.0	3.4	0.11%	
Binary Variable 2012	108.0	27.4	3.9	0.02%	
Binary Variable 2011	132.3	25.1	5.3	0.00%	
Binary Variable 2010	143.5	24.7	5.8	0.00%	
Binary Variable 2009	144.7	23.8	6.1	0.00%	
Binary Variable 2008	134.8	27.3	4.9	0.00%	
Model Fit					
R-Squared		0.98			
Adjusted R-Squared		0.98			
Mean Absoulte Per cent Error (MAPE)		3.7%			
Statistic for Auto-correlation					
Durbin Watson Statistics		2.19			

Table 18-3 Residential SAE Model – South Interior

South Interior Residential SAE Model					
Variable	Coefficient	Standard Error	T-Statistics	P-Value	
Constant	692.7	6.7	103.3	0.00%	
XHeat	1.6	0.0	48.2	0.00%	
XCool	0.3	0.0	6.0	0.00%	
Binary Variable 2018	(147.1)	38.1	-3.9	0.02%	
Binary Variable 2017	74.1	27.1	2.7	0.73%	
Binary Variable 2016	85.0	37.9	2.2	2.70%	
Binary Variable 2015	(51.9)	17.2	-3.0	0.32%	
Binary Variable 2014	(81.9)	26.7	-3.1	0.28%	
Binary Variable 2013	70.7	26.9	2.6	0.98%	
Binary Variable 2011	107.6	22.2	4.8	0.00%	
Binary Variable 2010	120.8	27.2	4.4	0.00%	
Binary Variable 2009	47.9	19.5	2.5	1.55%	
Model Fit					
R-Squared		0.97			
Adjusted R-Squared		0.97			
Mean Absoulte Per cent Error (MAPE)		2.6%			
Statistic for Auto-correlation					
Durbin Watson Statistics		1.61			

Table 18-4 Residential SAE Model – North Region

North Region Residential SAE Model					
Variable	Coefficient	Standard Error	T-Statistics	P-Value	
XHeat	1.5	0.1	23.6	0.00%	
XCool	(0.1)	0.0	-1.7	9.28%	
XOther	0.9	0.0	55.5	0.00%	
Binary Variable 2015	87.4	29.8	2.9	0.41%	
Binary Variable 2014	150.8	37.6	4.0	0.01%	
Binary Variable 2013	137.5	38.2	3.6	0.05%	
Binary Variable 2012	133.4	37.8	3.5	0.06%	
Binary Variable 2011	196.3	38.0	5.2	0.00%	
Binary Variable 2010	190.5	29.7	6.4	0.00%	
Binary Variable 2009	223.8	27.3	8.2	0.00%	
Binary Variable 2008	152.8	37.5	4.1	0.01%	
Model Fit					
R-Squared		0.94			
Adjusted R-Squared		0.94			
Mean Absoulte Per cent Error (MAPE)		5.07%			
Statistic for Auto-correlation					
Durbin Watson Statistics		1.58			

Table 18-5 Commercial SAE Model – Lower Mainland under 35kW

Lower Mainland Under 35kW SAE Model				
Variable	Coefficient	Standard Error	T-Statistic:	P-Value
Constant	102,881,241.3	19,678,787.6	5.2	0.00%
XHeat	4,243.6	616.6	6.9	0.00%
XCool	264.7	83.8	3.2	0.21%
XOther	421.9	178.6	2.4	2.00%
Trinary Variable 1	11,013,331.8	1,648,242.5	6.7	0.00%
Trinary Variable 2	15,853,572.6	1,897,333.4	8.4	0.00%
Binary Variable 2009	(7,704,217.4)	2,817,335.5	-2.7	0.73%
Binary Variable 2010	(10,237,229.9)	2,496,111.4	-4.1	0.01%
Binary Variable 2011	(5,755,850.7)	2,295,777.6	-2.5	1.37%
Binary Variable 2012	(5,453,473.7)	1,999,292.6	-2.7	0.75%
Binary Variable 2013	(2,263,640.9)	1,890,251.4	-1.2	23.38%
Binary Variable 2018	1,301,414.4	1,654,472.7	0.8	43.33%
Binary February	5,851,495.5	2,505,156.1	2.3	2.14%
Binary March	(7,606,317.9)	1,861,711.8	-4.1	0.01%
Binary August	5,597,559.8	2,983,358.4	1.9	6.34%
Binary November	(7,244,061.0)	2,385,983.2	-3.0	0.30%
Model Fit				
R-Squared		0.89		
Adjusted R-Squared		0.88		
Mean Absoulte Per cent Error (MAPE)		2.09%		
Statistic for Auto-correlation				
Durbin Watson Statistics		1.77		

Table 18-6 Commercial SAE Model – Lower Mainland over 35kW

Lower Mainland Over 35kW SAE Model				
Variable	Coefficient	Standard Error	T-Statistic:	P-Value
XHeat	1,165.0	1,155.0	1.0	31.54%
XCool	44.5	5.0	9.0	0.00%
XOther	1,518.5	13.3	114.6	0.00%
Trinary 2008	(54,466,703.6)	8,479,839.7	-6.4	0.00%
Trinary 2009	(38,970,695.4)	7,534,714.6	-5.2	0.00%
Trinary 2014	29,000,638.8	7,834,846.0	3.7	0.03%
Trinary 2016	44,756,601.7	5,358,455.5	8.4	0.00%
Trinary April and May	(45,996,226.9)	5,260,951.1	-8.7	0.00%
Trinary April and March 2010	(78,270,083.5)	23,590,137.1	-3.3	0.13%
Trinary Dec. 2013 and Jan 2014	(48,352,872.3)	16,944,176.3	-2.9	0.52%
Trinary Nov. and Dec. 2014	(64,272,440.0)	19,316,179.3	-3.3	0.12%
Trinary Dec. 2014 and Jan. 2015	(109,130,798.6)	19,763,391.4	-5.5	0.00%
Trinary Dec. 2016 and Jan. 2017	(87,389,687.3)	16,582,777.2	-5.3	0.00%
Trinary Dec. 2017 and Jan. 2018	(76,899,961.6)	16,581,787.2	-4.6	0.00%
Model Fit				
R-Squared		0.63		
Adjusted R-Squared		0.58		
Mean Absoulte Per cent Error (MAPE)		2.75%		
Statistic for Auto-correlation				
Durbin Watson Statistics		2.14		

Table 18-7 Commercial SAE Model – Vancouver Island under 35kW

Vancouver Island Under 35kW SAE Model				
Variable	Coefficient	Standard Error	T-Statistics	P-Value
XHeat	3,800.9	185.7	20.5	0.00%
XCool	453.9	97.2	4.7	0.00%
XOther	974.2	19.6	49.7	0.00%
Binary Variable 2009	(2,998,751.0)	814,128.9	-3.7	0.04%
Binary Variable 2014	2,595,278.8	786,687.4	3.3	0.13%
Trinary Variable 1	6,438,173.4	587,028.4	11.0	0.00%
Trinary Varaible 2	(1,741,303.6)	924,094.8	-1.9	6.21%
Trinary Variable 3	4,157,183.8	680,499.3	6.1	0.00%
Model Fit				
R-Squared		0.92		
Adjusted R-Squared		0.91		
Mean Absoulte Per cent Error (MAPE)		3.48%		
Statistic for Auto-correlation				
Durbin Watson Statistics		1.61		

Table 18-8 Commercial SAE Model – Vancouver Island over 35kW

Vancouver Island Over 35kW SAE Model				
Variable	Coefficient	Standard Error	T-Statistics	P-Value
XHeat	3,149.4	286.5	11.0	0.00%
XCool	53.6	11.7	4.6	0.00%
XOther	1,326.1	14.2	93.6	0.00%
Binary Variable 2009	(7,138,888.8)	1,664,190.5	-4.3	0.00%
Binary Variable 2010	(5,099,770.4)	1,658,288.4	-3.1	0.27%
Trinary Dec. and Jan.	(11,363,307.1)	1,166,765.9	-9.7	0.00%
Trinary Feb. and March 2011	(8,202,705.5)	3,673,911.2	-2.2	2.77%
Trinary April and May 2011	(16,711,294.5)	3,674,782.0	-4.5	0.00%
Trinary Feb and March 2013	10,651,647.4	3,677,563.2	2.9	0.46%
Trinary June and July 2015	(6,499,531.0)	3,734,136.3	-1.7	8.47%
Trinary April and May 2017	(8,208,160.8)	3,672,810.8	-2.2	2.75%
Binary Variable 2017	6,045,165.5	1,637,409.1	3.7	0.04%
Binary Variable 2015	5,428,625.7	1,641,736.3	3.3	0.13%
Binary Variable 2018	3,379,597.6	1,643,986.1	2.1	4.23%
Model Fit				
R-Squared		0.86		
Adjusted R-Squared		0.85		
Mean Absoulte Per cent Error (MAPE)		2.61%		

Table 18-9 Commercial SAE Model – South Interior under 35kW

South Interior Under 35kW SAE Model				
Variable	Coefficient	Standard Error	T-Statistics	P-Value
XHeat	2,145.2	106.0	20.2	0.00%
XCool	775.6	67.6	11.5	0.00%
XOther	1,136.8	17.5	64.9	0.00%
Binary Variable 2014	4,713,718.2	330,199.7	14.3	0.00%
Trinary Variable 1	3,869,053.9	299,070.5	12.9	0.00%
Trinary Jan . 2014 to May 2014	2,814,396.2	532,186.0	5.3	0.00%
Binary Variable 2009	(2,078,622.8)	508,159.0	-4.1	0.01%
Binary Variable 2010	(1,890,979.3)	502,365.6	-3.8	0.03%
Model Fit				
R-Squared		0.91		
Adjusted R-Squared		0.90		
Mean Absoulte Per cent Error (MAPE)		3.39%		
Statistic for Auto-correlation				
Durbin Watson Statistics		1.49		

Table 18-10 Commercial SAE Model – South Interior over 35kW

South Interior Over 35kW SAE Model				
Variable	Coefficient	Standard Error	T-Statistic:	P-Value
XHeat	3,913.6	571.7	6.8	0.00%
XCool	45.2	4.0	11.4	0.00%
XOther	1,537.3	20.8	73.8	0.00%
Binary Variable 2009	(14,830,219.8)	1,430,004.6	-10.4	0.00%
Binary Variable 2010	(9,456,723.8)	1,414,260.1	-6.7	0.00%
Binary Variable 2011	(9,043,975.4)	1,409,275.9	-6.4	0.00%
Binary Variable 2012	(6,968,840.1)	1,406,279.9	-5.0	0.00%
Binary Variable January	7,346,245.0	1,949,041.3	3.8	0.03%
Binary Variable May	5,152,948.1	1,612,426.9	3.2	0.19%
Binary Variable 2013	(5,573,403.4)	1,398,966.2	-4.0	0.01%
Trinary Dec. 2017 and Jan 2018	(5,774,474.3)	4,159,831.7	-1.4	16.81%
Trinary Dec. 2016 and Jan 2017	(8,799,379.9)	3,228,029.5	-2.7	0.75%
Trinary Mar. and April 2017	5,548,373.0	3,138,179.0	1.8	8.00%
Trinary Oct. and Nov. 2015	(6,429,265.2)	3,126,142.7	-2.1	4.22%
Trinary Jan. and Feb. 2012	(14,303,649.7)	3,260,486.7	-4.4	0.00%
Trinary Aug. and Sept. 2012	(5,373,445.3)	3,134,437.0	-1.7	8.95%
Trinary April and May 2011	(7,729,655.9)	3,208,934.3	-2.4	1.78%
Model Fit				
R-Squared		0.75		
Adjusted R-Squared		0.71		
Mean Absoulte Per cent Error (MAPE)		3.67%		
Statistic for Auto-correlation				
Durbin Watson Statistics		1.46		

Table 18-11 Commercial SAE Model – North Region under 35kW

North Region Under 35kW SAE Model				
Variable	Coefficient	Standard Error	T-Statistic:	P-Value
XHeat	19,575.6	996.1	19.7	0.00%
XCool	571.5	168.2	3.4	0.10%
XOther	1,186.5	20.4	58.2	0.00%
Binary Variable 2009	(2,756,757.8)	546,953.2	-5.0	0.00%
Binary Variable 2010	(3,156,547.3)	557,074.4	-5.7	0.00%
Binary Variable 2011	(1,751,082.1)	541,150.2	-3.2	0.16%
Binary Variable 2012	(967,867.4)	552,743.5	-1.8	8.29%
Binary Variable 2017	2,235,480.9	515,346.2	4.3	0.00%
Binary Variable 2018	1,298,549.3	515,413.8	2.5	1.33%
Trinary Variable 1	3,050,713.9	384,529.8	7.9	0.00%
Trinary Jan. to May 2015	3,247,674.3	754,291.1	4.3	0.00%
Trinary Feb. and March 2014	(1,124,299.0)	1,116,508.3	-1.0	31.63%
Trinary April and May 2014	(3,621,220.5)	1,120,617.4	-3.2	0.17%
Trinary March and April 2015	1,175,062.1	1,117,345.4	1.1	29.54%
Trinary April and May 2016	1,653,865.4	1,116,618.1	1.5	14.16%
Trinary April and May 2017	(2,480,636.5)	1,117,812.7	-2.2	2.87%
Trinary June and July 2009	(5,571,626.9)	1,675,149.2	-3.3	0.12%
Model Fit				
R-Squared		0.91		
Adjusted R-Squared		0.90		
Mean Absoulte Per cent Error (MAPE)		3.75%		
Statistic for Auto-correlation				
Durbin Watson Statistics		1.56		

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Table 18-12 Commercial SAE Model – North Region over 35kW

North Region Over 35kW SAE Model				
Variable	Coefficient	Standard Error	T-Statistic:	P-Value
Constant	32,643,291.3	6,657,780.1	4.9	0.00%
XHeat	2,836.8	317.9	8.9	0.00%
XCool	16.1	4.7	3.4	0.09%
XOther	691.1	171.1	4.0	0.01%
Binary Variable January	5,585,675.5	891,595.7	6.3	0.00%
Binary Variable December	(2,876,129.6)	831,840.5	-3.5	0.08%
Trinary April and May 2016	(3,757,126.7)	1,487,788.7	-2.5	1.31%
Trinary April and May 2010	(882,387.3)	1,495,903.6	-0.6	55.66%
Trinary Jan and Feb 2012	(5,308,590.9)	1,543,976.7	-3.4	0.09%
Trinary Nov. and Dec. 2012	(6,641,842.8)	1,503,192.4	-4.4	0.00%
Trinary March and April 2014	6,739,849.6	1,542,909.0	4.4	0.00%
Trinary May and June 2014	3,641,469.2	1,464,108.9	2.5	1.45%
Trinary Aug and Sep 2014	3,105,075.1	1,473,719.8	2.1	3.76%
Trinary Feb and March 2015	2,285,643.0	1,463,339.2	1.6	12.15%
Trinary April and May 2017	(3,124,414.7)	1,482,777.1	-2.1	3.76%
Binary Variable 2018	(5,185,324.9)	687,123.1	-7.5	0.00%
Binary Variable 2014	(4,110,274.1)	730,018.3	-5.6	0.00%
Binary Variable 2015	113,098.8	779,418.8	0.1	88.49%
Binary Variable 2016	(3,547,902.7)	763,153.7	-4.6	0.00%
Binary Variable 2017	(3,545,075.5)	757,950.1	-4.7	0.00%
Model Fit				
R-Squared		0.91		
Adjusted R-Squared		0.89		
Mean Absoulte Per cent Error (MAPE)		2.39%		
Statistic for Auto-correlation				
Durbin Watson Statistics		1.68		

19.0 Appendix E: Temperature Normalization & Residential Accounts Improvements

19.1 INTRODUCTION - TEMPERATURE NORMALIZATION

As mentioned in Section 5.1 of this report we develop a forecast of the average use per account and residential sales on a temperature normalized basis. We also develop a forecast of commercial sales on a temperature normalized basis. The forecasts for both of these sector forecasts are derived from our SAE models that include various drivers such as our heating and cooling degree day variables.

Since the forecasts are developed on a temperature normalized basis, we need to take the actual sales and temperature normalize them (i.e., adjust the historical sales for instances where actual temperature were different than assumed normal) to report variances and determine the accuracy of our forecasts. Temperature normalization is an estimation process because it involves using models and a series of steps to determine what the actual sales would have been if the actual temperatures variables (i.e., heating and cooling degree days) were at their normalized values (i.e., which is defined as the 10 year rolling average).

Each month, we temperature normalize the residential use per account and subsequently normalize the sales by multiplying the temperature normalized use per account by the accounts. We also temperature normalize the commercial sales. We currently temperature normalize the commercial sales at the end of the fiscal year using our SAE models. As part of the audit recommendations[45] we are working towards developing models and a process to temperature normalize commercial sales much like the way we normalize the actuals from residential sector, which is described below.

The following sections explain the temperature normalization process for the residential and commercial sectors.

19.2 TEMPERATURE NORMALIZATION PROCESSES STANDING APPROACH

Our current temperature normalization process for the residential and commercial sectors is described below. However, we are continuing to review the applicability of the residential approach described below to the commercial sector.

The central equation in determining a temperature normalized actual is:

Equation E.1

$$Temperature\ Normalized\ Actual = Actual + Model\ Projections\ Under\ Normal\ Temperatures - Model\ Projections\ Under\ Actual\ Temperatures$$

Where: Actual is the actual data from our billing system, Model Projections under Normal Temperature is an estimate[46]using our normal assumptions for heating and cooling degree days, and Model Projections under Actual Temperature is an under actual temperatures (i.e., actual heating and cooling degree days). The model projections are developed with an estimation period that does not include any of the forecast years. For example, our normalized residential and commercial results were done with data ending fiscal 2018.

[45] One of the Load Forecast Audit findings was to update our monthly variance report by including temperature normalized commercial monthly sales and comparing those estimates to the forecast on a monthly basis.

[46] Estimate in the context of temperature normalization means predication of average use per account for the residential sector and prediction of sales for the commercial sector.

19.3 RESIDENTIAL TEMPERATURE NORMALIZATION

To temperature normalize the use per account we use equation E.1 above use the in conjunction with model projections from the following regression model (equation E.2) below:

Equation E.2

$$USE_m = \alpha + \beta_1 \times WgtHCDD_m + \beta_2 \times WgtHCDD_m^2 + \beta_3 \times WgtHCDD_m^3 + \varepsilon_m$$

Where: USE_m is monthly average use per account per account for eight segments of residential load we normalize[47], β_1 to β_3 are the coefficients of the above cubic regression model, $WgtHCDD_m$ is a combination of weighted cooling and heating degree days in a month, $WgtHCDD_m^2$ and $WgtHCDD_m^3$ are squared and cubic weighted heating/cooling degree days[48]; and ε_m is the error term. The weights are used to align the combo of heating and cooling degree days to the monthly billing data.

The most recent 36 months of data is used to estimate the regression model as described in the equation E.2 above for each of the eight residential load segments that get normalized. Every month we determine the temperature normalized average use per account and the residential billed sales using the following steps:

1. we estimate the coefficients of the regression model using data from the past 36 months,
2. from estimated coefficients in equation E.2 we determine the model's prediction of the average use per account under actual temperatures for the past 36 months, including the prediction for the last month,
3. from the estimated coefficients in equation E.2 we determine the model's prediction under normal temperature by replacing the actual combined weighted heating and cooling degree days variables with these variables on a normalized basis; and
4. finally, we determine the temperature normalized average use per account for the month we are normalizing using equation E.1 above.

Normalized residential sales are then calculated for each load segment as the normalized average use per account multiplied by the average number of accounts for the segment. The total BC Hydro service area normalized residential sales in any month is equal to the sum of normalized sales for each segment; and the total normalized sales for a year would be sum over the past 12 months.

19.4 COMMERCIAL TEMPERATURE NORMALIZATION

The process for commercial normalization is similar to the four step process outlined above for the residential sector. The main differences to the residential process are: (i) the eight commercial SAE models and the last 10 years of monthly commercial sales data are used in the normalization process rather than monthly regression models using the past 36 months; (ii) the commercial sales are normalized at the end of year fiscal year using the commercial SAE model; and (iii) the heating and cooling degree variables in the commercial SAE models and the weights of these variables are different compared to the weights in the above residential models because the billing cycle is different for the commercial segments of load compared to the residential sector.

[47] The residential load segments we normalize are the heating and non-heating accounts in each of the four service regions, as such there are eight load segments (2 heating types and 4 regions).

[48] Because billing data of use per account is used in the temperature normalization process, the combined cooling and heating degree-days are weighted as percentages of the current and previous month to match the meter reading cycle for our residential customers. The weighting process is also an element of our SAE model.

19.5 RESIDENTIAL ACCOUNTS IMPROVEMENTS

As mentioned in Section 3.2.4 of this report, we indicated that we have modified our methodology on how we forecast residential accounts. The new methodology recognizes that based on a historical analysis of account growth and housing growth that there is not a one to one ratio in these variables which was assumed in previous forecasts. The details of the revised method of forecasting the residential accounts are contained in Section 4.2.1 above.

We have not re-estimated the accounts forecast for the past 10 successive forecasts with the revised methodology because of the considerable effort that would be required. However, to demonstrate our belief that the new approach will lead to a more accurate forecast, we re-estimated the 2012 and 2011 accounts forecast using the main aspect of the new methodology. The 2011 and 2012 accounts forecasts were re-developed by applying historical ratio of accounts growth to housing starts growth.[49]

Table 19-1 below summarizes the variance (i.e., actual less forecast of accounts) for the total BC Hydro service area of the original 2011 and 2012 accounts forecast and our re-estimated accounts forecast that was developed by applying a historical ratio of account growth and housing starts to the housing starts forecast. This ratio was determined at the BC Hydro service area level by computing a five year average of historical account growth to housing growth prior to the forecast period. The re-estimated accounts is a simplified version of our new method in that the ratios used for the re-estimated forecasts were developed at the BC Hydro level rather than ratios from a detailed analysis of the15 areas for which we develop an accounts projection. As well, the re-estimation of the accounts for the 2011 and 2012 forecast periods do not include a separate analysis for the first year of the forecasts using the billing data trends at the time when these forecasts were prepared.

The results summarized in Table 19-1 show lower variances of re-estimated forecast vintages using the new method compared to the original accounts forecasts. This illustrates the new method is an improvement (i.e., greater accuracy) in the approach to developing our accounts forecasts.

[49] At the time, the 2012 and 2011 accounts forecast used net housing starts rather than growth in net housing stock.

Table 19-1 Variance Analysis of 2011 and 2012 Residential Account Forecasts

Fiscal year	2011 Variance of Original Forecast	2011 Variance Re-Estimated Forecast Reflecting Ratio Methodology Approach	2012 Variance of Original Forecast	2012 Variance Re-Estimated Forecast Reflecting Ratio Methodology Approach
F2012	-0.5%	-0.2%		
F2013	-0.9%	-0.6%	-0.2%	0.0%
F2014	-1.2%	-1.0%	-0.4%	-0.2%
F2015	-1.7%	-1.5%	-0.7%	-0.5%
F2016	-2.1%	-1.8%	-0.8%	-0.6%
F2017	-2.4%	-2.1%	-1.0%	-0.8%
F2018	-2.6%	-2.3%	-1.2%	-0.9%
Average Variance	-1.6%	-1.4%	-0.7%	-0.5%

20.0 Appendix F: Economic Forecasts and Other Drivers

Table F-1 and Table F-2 contains a summary of the forecasts of the economic drivers, at the BC Hydro service area, used in developing the October 2018 Load Forecast for the residential, commercial and light industrial sectors.

The forecasts of these economic drivers comes from the Conference Board of Canada June 2018 Economic Forecast. The Conference Board of Canada was selected by BC Hydro to provide a history and forecast of economic variables for 15 sub areas, 4 service regions, and the total province. The regional break-down of the economic drivers in Table F-1 and Table F-2 are included in the Statistically Adjusted End Use (SAE) models for the residential and commercial sector.

Table F-2 also contains the five year forecast (2018 to 2022) of real provincial GDP growth from the BC Ministry of Finance as per their First Quarterly Report issued September 7, 2018. The provincial GDP forecast for the first five years is used to develop an unadjusted electricity sales forecast for the other light industrial sub-sector.

Table F-1 Key economic drivers for Residential sector and SAE models

Key Economic Drivers for Residntail Sector and SAE Models[1]

	Fiscal Year	Calendar Year	Population BC Hydro Service Area	Housing Starts BC Hydro Service Area	Net Housing Stock BC Hydro Service Area	Residential Accounts BC Hydro Service Area	Population per Account BC Hydro Service Area	Real Disposable Income Annual Growth % BC Hydro Service Area
History	F2018	2017	4,429,652	37,635	26,795	1,803,791	2.46	5.4%
Fcst	F2019	2018	4,481,175	40,395	39,202	1,831,954	2.45	3.7%
Fcst	F2020	2019	4,533,098	32,504	34,550	1,861,572	2.44	2.2%
Fcst	F2021	2020	4,578,786	28,009	29,698	1,885,943	2.43	2.4%
Fcst	F2022	2021	4,625,280	26,499	26,383	1,907,221	2.43	1.9%
Fcst	F2023	2022	4,672,570	26,003	24,979	1,927,188	2.42	2.1%
Fcst	F2024	2023	4,720,639	25,483	24,363	1,946,489	2.43	2.3%

Notes

1 . History and Forecast for all data in the table above except accounts comes from the Conference Board of Canada June 2018.

Table F-2 Key economic drivers for Commercial sector and SAE models

Key Economic Forecast for Commercial Sector and SAE Models and Light Industrial Sector

			Commercial Economic Drivers[2]			Light Industrial Economic Drivers
	Fiscal Year	Calendar Year	Employment Annual Growth % BC Hydro Service Area	Real Retail Sales Annual Growth % BC Hydro Service Area	Real Commercial GDP Annual Growth % BC Hydro Service Area	Real BC Provincial GDP Annual Growth[3] % BC Hydro Service Area
History	F2018	2017	3.7%	8.5%	3.7%	3.6%
Fcst	F2019	2018	1.5%	3.6%	2.7%	2.2%
Fcst	F2020	2019	1.2%	2.1%	2.6%	1.8%
Fcst	F2021	2020	1.4%	2.3%	2.6%	2.0%
Fcst	F2022	2021	1.4%	1.9%	2.2%	2.0%
Fcst	F2023	2022	1.1%	2.1%	2.1%	2.0%
Fcst	F2024	2023	0.8%	2.3%	2.0%	2.3%

Notes

2 . History and Forecast for all data in the table above comes from the Conference Board of Canada June, 2018 Economic Forecast.

3. History comes from BC Stats while forecast of real BC GDP growth from 2018 to 2022 comes of BC Ministry of Finance, First Quarter Report, issued September 7, 2018.

Forecast of Real BC GDP for calendar 2023 comes from the Conference Board of Canada June 2018 Economic Forecast.

Table F-3 below is the 2018 EIA projections of average efficiency residential end uses for the Pacific Region which are include in the October 2018 residential SAE models. Table F-4 contains the 2018 EIA projections of average efficiency projection commercial end use of electricity for Pacific region which are contained the commercial SAE models. The lighting efficiency is unchanged from the EIA's 2017 level which is how we account for overlap in codes and standards for lighting. For additional details on overlap in codes and standards see Section 12.

Table F-3 EIA Average Efficiencies of Residential End Uses

Calendar Year		HPHeat	GHPHeat	SecHt	CAC	HPCool	GHPCool	RAC	EWHeat	ECook	Ref1	Ref2	Frz	Dish	CWash	EDry	TV	FurnFan	Light	Misc
1995	3	7	3	3	9	9	11	8	1	419	993	894	879	1	0	3	602	246	1,701	1,395
1996	3	7	3	3	9	10	11	8	1	419	953	857	847	1	0	3	613	247	1,738	1,447
1997	3	7	3	3	9	10	11	8	1	419	917	825	817	1	0	3	624	247	1,776	1,499
1998	3	7	3	3	9	10	11	8	1	419	886	797	786	1	0	3	657	248	1,815	1,554
1999	3	7	3	3	10	10	12	8	1	419	874	786	772	1	0	3	696	248	1,855	1,609
2000	3	7	3	3	10	10	12	8	1	418	857	771	754	1	0	3	734	249	1,895	1,666
2001	3	7	3	3	10	10	12	9	1	418	827	744	727	1	0	3	756	249	1,936	1,724
2002	3	7	3	3	10	11	12	9	1	418	800	720	704	1	0	3	765	250	1,978	1,784
2003	3	7	3	3	10	11	12	9	1	418	776	698	682	1	0	3	773	250	1,981	1,845
2004	3	7	3	3	11	11	12	9	1	417	752	677	639	1	0	3	782	251	1,984	1,907
2005	3	7	3	3	11	11	12	9	1	417	729	656	618	1	0	3	791	251	1,986	1,971
2006	3	7	3	3	11	12	12	9	1	416	716	645	611	1	0	3	797	252	1,913	2,008
2007	3	8	3	3	11	12	12	9	1	416	704	634	604	1	0	3	802	252	1,843	2,045
2008	3	8	3	3	11	12	12	9	1	418	692	623	598	1	0	3	808	253	1,778	2,082
2009	3	8	3	3	11	12	12	9	1	416	681	613	593	1	0	3	814	253	1,722	2,127
2010	3	8	3	3	12	12	13	9	1	416	670	603	588	1	0	3	809	250	1,462	2,236
2011	3	8	3	3	12	13	13	9	1	416	660	594	584	1	0	3	805	246	1,413	2,345
2012	3	8	3	3	12	13	13	10	1	417	649	584	578	1	0	3	800	242	1,397	2,454
2013	3	8	3	3	12	13	13	10	1	416	638	574	572	1	0	3	785	238	1,264	2,563
2014	3	8	3	3	12	13	13	10	1	415	623	561	559	1	0	3	783	235	1,213	2,673
2015	3	8	3	3	12	13	13	10	1	415	610	549	550	1	0	3	777	231	1,104	2,782
2016	3	8	3	3	12	13	14	10	1	415	596	537	540	1	0	3	765	227	1,042	2,839
2017	3	8	3	3	13	14	14	10	1	415	583	524	530	1	0	3	753	223	988	2,896
2018	3	8	3	3	13	14	14	10	1	415	570	513	520	1	0	3	747	220	988	2,993
2019	3	8	3	3	13	14	14	10	1	414	558	502	509	1	0	3	742	216	988	3,022
2020	3	8	3	3	13	14	14	11	1	414	546	492	499	1	0	3	737	214	988	3,002
2021	3	8	3	3	13	15	14	11	1	414	535	482	488	1	0	4	732	213	988	2,975
2022	3	8	3	3	13	15	15	11	1	414	525	472	478	1	0	4	727	212	988	2,952
2023	3	8	3	3	13	15	15	11	1	414	515	464	469	1	0	4	724	210	988	2,925

Equipment Definitions and Units		
EFurn	Electric furnace and resistant room space heaters	Constant
HPHeat	Heat pump space heating	HSPF
GHPHeat	Ground-source heat pump space heating	COP
SecHt	Secondary heating	Constant
CAC	Central air conditioning	SEER
HPCool	Heat pump space cooling	SEER
GHPCool	Ground-source heat pump space cooling	EER
RAC	Room air conditioners	EER
EWHeat	Electric water heating	EF
ECook	Electric cooking	kWh/year
Ref1	Refrigerator	kWh/year
Ref2	Second refrigerator	kWh/year
Frz	Freezer	kWh/year
Dish	Dishwasher	EF
CWash	Electric clothes washer	kWh/load
EDry	Electric clothes dryer	EF
TV	TV sets	kWh/year
FurnFan	Furnace fans	kWh/year
Light	Lighting	kWh/year
Misc	Miscellaneous electric appliances	kWh/year
HSPF :	Heating Seasonal Performance Factor. The total heating output of a heat pump in BTU during its normal annual usage	
	period for heating divided by total electric input in watt-hours during the same period.	
COP :	Coefficient of Performance: Energy efficiency rating measure determined, under specific testing conditions, by dividing the energy output by the energy input.	
SEER :	Seasonal Energy Efficiency Ratio: The total cooling of a central unitary air conditioner or a unitary heat pump in	
	Btu during its normal annual usage period for cooling divided by the total electric energy input in watt-hours during the same period.	
EER :	Energy Efficiency Ratio. A ratio calculated by dividing the cooling capacity in Btu per hour by the power input in	
	watts at any given set of rating conditions, expressed in Btu per hour per watt.	
EF :	Efficiency Factor. Efficiency (measured in Btu out / Btu in) of water heaters under certain test conditions specified	
	by the US Department of Energy.	

Table F-4 EIA Average Efficiencies of Commercial End Uses

	Electric Space Heating	Electric Air Conditioning	Ventilation	Electric Water Heating	Electric Cooking	Refigeration	OutDoor Lighting	Indoor Lighting	Office Equipment	Misc Electric Appliance
1995	1.09	2.66	0.43	0.95	0.64	2.20	35.68	35.68	1.00	1.00
1996	1.10	2.66	0.43	0.95	0.64	2.20	35.77	35.77	1.00	1.00
1997	1.10	2.66	0.43	0.95	0.64	2.20	35.88	35.88	1.00	1.00
1998	1.12	2.70	0.45	0.95	0.65	2.22	35.95	35.95	1.00	1.00
1999	1.13	2.74	0.46	0.95	0.65	2.24	36.03	36.03	1.00	1.00
2000	1.14	2.78	0.47	0.95	0.66	2.25	36.10	36.10	1.00	1.00
2001	1.15	2.83	0.48	0.96	0.67	2.26	36.18	36.18	1.00	1.00
2002	1.16	2.86	0.49	0.96	0.67	2.28	36.30	36.30	1.00	1.00
2003	1.17	2.89	0.50	0.96	0.67	2.28	36.80	36.80	1.00	1.00
2004	1.19	2.91	0.50	0.96	0.68	2.29	37.09	37.09	1.00	1.00
2005	1.21	2.95	0.50	0.96	0.68	2.32	38.45	38.45	1.00	1.00
2006	1.24	2.99	0.49	0.96	0.69	2.34	40.01	40.01	1.00	1.00
2007	1.26	3.03	0.49	0.97	0.69	2.37	41.61	41.61	1.00	1.00
2008	1.29	3.07	0.49	0.97	0.69	2.39	44.33	44.33	1.00	1.00
2009	1.31	3.10	0.48	0.98	0.70	2.43	46.82	46.82	1.00	1.00
2010	1.33	3.14	0.48	0.99	0.70	2.46	49.24	49.24	1.00	1.00
2011	1.35	3.16	0.48	0.99	0.70	2.50	51.45	51.45	1.00	1.00
2012	1.36	3.18	0.49	1.00	0.70	2.57	53.63	53.63	1.00	1.00
2013	1.38	3.22	0.49	1.00	0.71	2.63	55.62	55.62	1.00	1.00
2014	1.39	3.25	0.49	1.01	0.71	2.63	57.13	57.13	1.00	1.00
2015	1.41	3.29	0.49	1.01	0.72	2.63	58.39	58.39	1.00	1.00
2016	1.42	3.34	0.49	1.02	0.72	2.64	59.46	59.46	1.00	1.00
2017	1.43	3.37	0.49	1.02	0.72	2.64	60.37	60.37	1.00	1.00
2018	1.45	3.42	0.49	1.03	0.73	2.65	60.37	60.37	1.00	1.00
2019	1.46	3.47	0.49	1.03	0.73	2.66	60.37	60.37	1.00	1.00
2020	1.47	3.51	0.49	1.04	0.73	2.69	60.37	60.37	1.00	1.00
2021	1.49	3.55	0.49	1.04	0.73	2.71	60.37	60.37	1.00	1.00
2022	1.51	3.59	0.49	1.05	0.74	2.74	60.37	60.37	1.00	1.00
2023	1.53	3.63	0.50	1.05	0.74	2.76	60.37	60.37	1.00	1.00

Commercial

End Use Definitions

Electric space heating	Btu (energy) out/ Btu (energy) in
Electric air conditioning	Btu (energy) out/ Btu (energy) in
Ventilation	Btu (energy) out/ Btu (energy) in
Electric water heating	Btu (energy) out/ Btu (energy) in
Electric cooking	Btu (energy) out/ Btu (energy) in
Refrigeration	Btu (energy) out/ Btu (energy) in
Exterior lighting	Lumens per watt
Interior lighting	Lumens per watt
Office equipment	Constant
Miscellaneous electric appliance	Constant

21.0 Appendix G: October 2018 Load Forecast Tables

Table G-1 Temperature Normalized Actuals and Forecasts Before Rate Impacts

Total Hydro		OCTOBER 2018 FORECAST - BEFORE RATE IMPACTS													
	Resid-ential Sales (GWh)	Commercial Sales (GWh)	Light Industrial (GWh)	Commercial/ Light Industrial[1] (GWh)	Large Industrial Sales (GWh)	Irrig Str Lt BCH Own Use Sales (GWh)	Total BC Hydro Service Area Sales (GWh)	Sales to City of New Westminster & FortisBC Electric Sales (GWh)	Sales to Seatle City Light Hyder, Alaska Sales (GWh)	Total Firm Sales (GWh)	Total System Losses (GWh)	Total Gross System Require-ments (GWh)	Losses % of Total Sales (GWh)	Integrated Total Gross System Require-ments (GWh)	Total Domestic Sales (GWh)
Temperature Normalized Actuals															
F2013	17,852	14,333	3,994	18,327	13,530	365	50,075	795	311	51,181	5,450	56,596	10.6%	56,267	51,108
F2014	17,928	14,343	4,164	18,507	13,972	369	50,776	949	309	52,034	5,535	57,591	10.6%	57,261	51,958
F2015	17,973	14,460	4,227	18,687	14,055	369	51,084	966	306	52,357	4,380	56,992	8.4%	56,663	52,284
F2016	18,019	14,257	4,148	18,405	13,698	393	50,515	971	309	51,795	5,531	57,326	10.7%	56,998	51,725
F2017	17,952	14,582	4,275	18,856	13,106	381	50,295	1,053	319	51,667	5,195	56,862	10.1%	56,533	51,597
F2018	17,997	14,513	4,364	18,877	13,513	382	50,768	1,016	313	52,098	5,547	57,644	10.6%	57,330	52,024
Forecast															
F2019	18,368	14,665	4,410	19,075	14,026	406	51,875	961	312	53,147	5,344	58,491	10.1%	58,169	53,051
F2020	18,693	14,742	4,540	19,282	15,061	491	53,528	1,012	312	54,853	5,489	60,341	10.0%	60,013	54,672
F2021	19,033	14,787	4,771	19,558	14,740	501	53,831	1,027	312	55,170	5,536	60,707	10.0%	60,376	54,982
F2022	19,341	14,854	4,806	19,660	14,659	502	54,162	1,057	314	55,533	5,577	61,110	10.0%	60,742	55,344
F2023	19,655	14,873	4,843	19,716	15,006	429	54,805	1,077	312	56,195	5,630	61,825	10.0%	61,456	56,080
F2024	19,974	14,926	4,870	19,796	16,102	390	56,263	1,073	312	57,648	5,719	63,367	9.9%	62,997	57,573
Actual															
5yr Growth[4]															
F13-F18	0.2%	0.2%	1.8%	0.6%	0.0%	0.9%	0.3%	5.0%	0.1%	0.4%	0.4%		0.0%	0.4%	0.4%
Fcst															
5yr Growth[4]															
F18-F23	1.8%	0.5%	2.1%	0.9%	2.1%	2.4%	1.5%	1.2%	-0.1%	1.5%	0.3%		-1.2%	1.4%	1.5%

Notes:

1 Light Industrial/Commercial is the sum of the loads in the light industrial sector and commercial sector.
2 Domestic sales equals total firm sales less sales to BC Hydro own use.
3 Forecast for fiscal 2019 does not include actuals sales over the first six months of fiscal 2019
4 Growth rates are computed over a five year period on an annual compound growth basis.

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Table G-2 Temperature Normalized Actuals and Forecast After Rate Impacts

Total Hydro		OCTOBER 2018 FORECAST - AFTER RATE IMPACTS													
	Resid- ential Sales (GWh)	Commercial Sales (GWh)	Light Industiral (GWh)	Commercial/ Light Industrial[1] (GWh)	Large Industrial Sales (GWh)	Irrig Str Lt BCH Own Use Sales (GWh)	Total BC Hydro Service Area Sales (GWh)	Sales to City of New Westminster & FortisBC Electric Sales (GWh)	Sales to Seatle City Light Hyder, Alaska Sales (GWh)	Total Firm Sales (GWh)	Total System Losses (GWh)	Total Gross System Require- ments (GWh)	Losses % of Total Sales (GWh)	Integrated Total Gross System Require- ments (GWh)	Total Domestic Sales (GWh)
Temperature Normalized Actuals															
F2013	17,852	14,333	3,994	18,327	13,530	365	50,075	795	311	51,181	5,450	56,596	10.6%	56,267	51,108
F2014	17,928	14,343	4,164	18,507	13,972	369	50,776	949	309	52,034	5,535	57,591	10.6%	57,261	51,958
F2015	17,973	14,460	4,227	18,687	14,055	369	51,084	966	306	52,357	4,380	56,992	8.4%	56,663	52,284
F2016	18,019	14,257	4,148	18,405	13,698	393	50,515	971	309	51,795	5,531	57,326	10.7%	56,998	51,725
F2017	17,952	14,582	4,275	18,856	13,106	381	50,295	1,053	319	51,667	5,195	56,862	10.1%	56,533	51,597
F2018	17,997	14,513	4,364	18,877	13,513	382	50,768	1,016	313	52,098	5,547	57,644	10.6%	57,330	52,024
Forecast															
F2019	18,361	14,659	4,409	19,067	14,020	406	51,855	961	312	53,127	5,345	58,472	10.1%	58,150	53,031
F2020	18,679	14,731	4,537	19,267	15,050	491	53,486	1,012	312	54,810	5,488	60,299	10.0%	59,970	54,631
F2021	19,007	14,767	4,764	19,531	14,720	500	53,757	1,027	312	55,096	5,534	60,630	10.0%	60,300	54,908
F2022	19,303	14,825	4,796	19,622	14,631	501	54,057	1,056	314	55,426	5,574	61,000	10.1%	60,633	55,238
F2023	19,605	14,835	4,831	19,666	14,969	428	54,667	1,076	312	56,055	5,629	61,684	10.0%	61,316	55,941
F2024	19,912	14,880	4,855	19,735	16,054	389	56,089	1,071	312	57,473	5,743	63,216	10.0%	62,847	57,398
Actual															
5yr Growth[4]															
F13-F18	0.2%	0.2%	1.8%	0.6%	0.0%	0.9%	0.3%	5.0%	0.1%	0.4%	0.4%	0.4%	0.0%	0.4%	0.4%
Fcst															
5yr Growth[4]															
F18-F23	1.7%	0.4%	2.1%	0.8%	2.1%	2.3%	1.5%	1.1%	-0.1%	1.5%	0.3%	1.4%	-1.2%	1.4%	1.5%

Notes:

1 Light Industrial/Commercial is the sum of the loads in the light industrial sector and commercial sector.

2 Domestic sales equals total firm sales less sales to BC Hydro own use.

3 Forecast for fiscal 2019 does not include actuals sales over the first six months of fiscal 2019

4 Growth rates are computed over a five year period on an annual compound growth basis.

Table G-3 Temperature Normalized Actuals and Forecast After Rate Impacts After DSM and Loss Reduction Savings

Total Hydro — OCTOBER 2018 LOAD FORECAST - WITH DSM AND LOSS REDUCTIONS1

	Residential Sales (GWh)	Commercial Sales (GWh)	Light Industiral (GWh)	Commercial Light Industrial2 (GWh)	Large Industrial Sales (GWh)	Irrig Str Lt BCH Own Use Sales (GWh)	Total BC Hydro Service Area Sales (GWh)	Sales to City of New Westminster & FortisBC Electric Sales (GWh)	Sales to Seatle City Light Hyder, Alaska Sales (GWh)	Total Firm Sales (GWh)	Total System Losses (GWh)	Total Gross System Require-ments (GWh)	Losses % of Total Sales (GWh)	Integrated Total Gross System Require-ments (GWh)	Total Domestic3 Sales (GWh)
Temperature Normalized Actuals															
F2013	17,852	14,333	3,994	18,327	13,530	365	50,075	795	311	51,181	5,450	56,596	10.6%	56,267	51,108
F2014	17,928	14,343	4,164	18,507	13,972	369	50,776	949	309	52,034	5,535	57,591	10.6%	57,261	51,958
F2015	17,973	14,460	4,227	18,687	14,055	369	51,084	966	306	52,357	4,380	56,992	8.4%	56,663	52,284
F2016	18,019	14,257	4,148	18,405	13,698	393	50,515	971	309	51,795	5,531	57,326	10.7%	56,998	51,725
F2017	17,952	14,582	4,275	18,856	13,106	381	50,295	1,053	319	51,667	5,195	56,862	10.1%	56,533	51,597
F2018	17,997	14,513	4,364	18,877	13,513	382	50,768	1,016	313	52,098	5,547	57,644	10.6%	57,330	52,024
Forecast															
F20194	18,198	14,568	4,390	18,958	13,856	406	51,418	961	312	52,691	5,302	57,993	10.1%	57,671	52,594
F2020	18,253	14,484	4,487	18,971	14,702	491	52,417	1,012	312	53,741	5,382	59,124	10.0%	58,796	53,561
F2021	18,324	14,352	4,683	19,036	14,243	500	52,102	1,027	312	53,441	5,368	58,809	10.0%	58,480	53,253
F2022	18,411	14,244	4,688	18,931	14,066	501	51,909	1,056	314	53,279	5,356	58,634	10.1%	58,269	53,090
F2023	18,551	14,113	4,697	18,810	14,371	428	52,160	1,076	312	53,548	5,372	58,920	10.0%	58,554	53,434
F2024	18,709	14,034	4,697	18,731	15,414	389	53,243	1,071	312	54,627	5,449	60,076	10.0%	59,710	54,552
Actual															
5yr Growth5															
F13-F18	0.2%	0.2%	1.8%	0.6%	0.0%	0.9%	0.3%	5.0%	0.1%	0.4%	0.4%	0.4%	0.0%	0.4%	0.4%
Fcst															
5yr Growth5															
F18-F23	0.6%	-0.6%	1.5%	-0.1%	1.2%	2.3%	0.5%	1.1%	-0.1%	0.6%	-0.6%	0.4%	-1.2%	0.4%	0.5%

Notes:

1 Forecasts in table above includes all load reductions from rate impacts, DSM savings and loss reductions.
2 Light Industrial/Commercial is the sum of the loads in the light industrial sector and commercial sector.
3 Domestic sales equals total firm sales less sales to BC Hydro own use.
4 Forecast for fiscal 2019 does not include actuals sales over the first six months of fiscal 2019
5 Growth rates are computed over a five year period on an annual compound growth basis.

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Table G-4 Actuals and Forecasts Before Rate Impacts

Total Hydro	OCTOBER 2018 FORECAST - BEFORE RATE IMPACTS														
	Resid-ential Sales (GWh)	Commercial Sales (GWh)	Light Industiral (GWh)	Commercial/ Light Industrial[1] (GWh)	Large Industrial Sales (GWh)	Irrig Str Lt BCH Own Use Sales (GWh)	Total BC Hydro Service Area Sales (GWh)	Sales to City of New Westminster & FortisBC Electric Sales (GWh)	Sales to Seatle City Light Hyder, Alaska Sales (GWh)	Total Firm Sales (GWh)	Total System Losses (GWh)	Total Gross System Require-ments (GWh)	Losses % of Total Sales (GWh)	Integrated Total Gross System Require-ments (GWh)	Total Domestic[2] Sales (GWh)
Actual															
F2013	17,844	14,296	3,994	18,290	13,530	365	50,030	795	311	51,136	4,502	56,584	8.8%	56,255	51,063
F2014	18,019	14,383	4,164	18,547	13,972	369	50,907	949	309	52,165	5,674	57,712	10.9%	57,382	52,089
F2015	17,162	14,437	4,227	18,664	14,055	369	50,249	966	306	51,522	5,447	55,807	10.6%	55,478	51,449
F2016	17,269	14,288	4,148	18,436	13,698	392	49,795	971	309	51,075	5,545	56,525	10.9%	56,198	51,006
F2017	17,989	14,572	4,275	18,847	13,106	381	50,323	1,053	319	51,695	5,198	56,893	10.1%	56,564	51,625
F2018	18,148	14,539	4,364	18,903	13,513	382	50,946	1,016	313	52,276	5,566	57,842	10.6%	57,527	52,202
Forecast															
F2019[3]	18,368	14,665	4,410	19,075	14,026	406	51,875	961	312	53,147	5,344	58,491	10.1%	58,169	53,051
F2020	18,693	14,742	4,540	19,282	15,061	491	53,528	1,012	312	54,853	5,489	60,341	10.0%	60,013	54,672
F2021	19,033	14,787	4,771	19,558	14,740	501	53,831	1,027	312	55,170	5,536	60,707	10.0%	60,376	54,982
F2022	19,341	14,854	4,806	19,660	14,659	502	54,162	1,057	314	55,533	5,577	61,110	10.0%	60,742	55,344
F2023	19,655	14,873	4,843	19,716	15,006	429	54,805	1,077	312	56,195	5,630	61,825	10.0%	61,456	56,080
F2024	19,974	14,926	4,870	19,796	16,102	390	56,263	1,073	312	57,648	5,719	63,367	9.9%	62,997	57,573
Actual															
5yr Growth[4]															
F13-F18	0.3%	0.3%	1.8%	0.7%	0.0%	0.9%	0.4%	5.0%	0.1%	0.4%	4.3%	0.4%	3.9%	0.4%	0.4%
Fcst															
5yr Growth[4]															
F18-F23	1.6%	0.5%	2.1%	0.8%	2.1%	2.4%	1.5%	1.2%	-0.1%	1.5%	0.2%	1.3%	-1.2%	1.3%	1.4%

Notes:
1 Light Industrial/Commercial is the sum of the loads in the light industrial sector and commercial sector.
2 Domestic sales equals total firm sales less sales to BC Hydro own use.
3 Forecast for fiscal 2019 does not include actuals sales over the first six months of fiscal 2019
4 Growth rates are computed over a five year period on an annual compound growth basis.

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Table G-5 Actuals and Forecast After Rate Impacts

Total Hydro	OCTOBER 2018 FORECAST - AFTER RATE IMPACTS														
	Resid-ential Sales (GWh)	Commercial Sales (GWh)	Light Industiral (GWh)	Commercial/ Light Industrial[1] (GWh)	Large Industrial Sales (GWh)	Irrig Str Lt BCH Own Use Sales (GWh)	Total BC Hydro Service Area Sales (GWh)	Sales to City of New Westminster & FortisBC Electric Sales (GWh)	Sales to Seatle City Light Hyder, Alaska Sales (GWh)	Total Firm Sales (GWh)	Total System Losses (GWh)	Total Gross System Require-ments (GWh)	Losses % of Total Sales (GWh)	Integrated Total Gross System Require-ments (GWh)	Total Domestic[2] Sales (GWh)
Actual															
F2013	17,844	14,296	3,994	18,290	13,530	365	50,030	795	311	51,136	4,502	56,584	8.8%	56,255	51,063
F2014	18,019	14,383	4,164	18,547	13,972	369	50,907	949	309	52,165	5,674	57,712	10.9%	57,382	52,089
F2015	17,162	14,437	4,227	18,664	14,055	369	50,249	966	306	51,522	5,447	55,807	10.6%	55,478	51,449
F2016	17,269	14,288	4,148	18,436	13,698	392	49,795	971	309	51,075	5,545	56,525	10.9%	56,198	51,006
F2017	17,989	14,572	4,275	18,847	13,106	381	50,323	1,053	319	51,695	5,198	56,893	10.1%	56,564	51,625
F2018	18,148	14,539	4,364	18,903	13,513	382	50,946	1,016	313	52,276	5,566	57,842	10.6%	57,527	52,202
Forecast															
F2019[3]	18,361	14,659	4,409	19,067	14,020	406	51,855	961	312	53,127	5,345	58,472	10.1%	58,150	53,031
F2020	18,679	14,731	4,537	19,267	15,050	491	53,486	1,012	312	54,810	5,488	60,299	10.0%	59,970	54,631
F2021	19,007	14,767	4,764	19,531	14,720	500	53,757	1,027	312	55,096	5,534	60,630	10.0%	60,300	54,908
F2022	19,303	14,825	4,796	19,622	14,631	501	54,057	1,056	314	55,426	5,574	61,000	10.1%	60,633	55,238
F2023	19,605	14,835	4,831	19,666	14,969	428	54,667	1,076	312	56,055	5,629	61,684	10.0%	61,316	55,941
F2024	19,912	14,880	4,855	19,735	16,054	389	56,089	1,071	312	57,473	5,743	63,216	10.0%	62,847	57,398
Actual															
5yr Growth[4]															
F13-F18	0.3%	0.3%	1.8%	0.7%	0.0%	0.9%	0.4%	5.0%	0.1%	0.4%	4.3%	0.4%	3.9%	0.4%	0.4%
Fcst															
5yr Growth[4]															
F18-F23	1.6%	0.4%	2.1%	0.8%	2.1%	2.3%	1.4%	1.1%	-0.1%	1.4%	0.2%	1.3%	-1.2%	1.3%	1.4%

Notes:

1 Light Industrial/Commercial is the sum of the loads in the light industrial sector and commercial sector.
2 Domestic sales equals total firm sales less sales to BC Hydro own use.
3 Forecast for fiscal 2019 does not include actuals sales over the first six months of fiscal 2019
4 Growth rates are computed over a five year period on an annual compound growth basis.

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Table G-6 Actuals and Forecast After Rate Impacts and After DSM and Loss Reduction Savings

Total Hydro — OCTOBER 2018 LOAD FORECAST WITH DSM AND LOSS REDUCTION[1]

	Resid-ential Sales (GWh)	Commercial Sales (GWh)	Light Industrial (GWh)	Commercial Light Industrial[2] (GWh)	Large Industrial Sales (GWh)	Irrig Str Lt BCH Own Use Sales (GWh)	Total BC Hydro Service Area Sales (GWh)	Sales to City of New Westminster & FortisBC Electric Sales (GWh)	Sales to Seatle City Light Hyder, Alaska Sales (GWh)	Total Firm Sales (GWh)	Total System Losses (GWh)	Total Gross System Require-ments (GWh)	Losses % of Total Sales (GWh)	Integrated Total Gross System Require-ments (GWh)	Total Domestic[3] Sales (GWh)
Actual															
F2013	17,844	14,296	3,994	18,290	13,530	365	50,030	795	311	51,136	4,502	56,584	8.8%	56,255	51,063
F2014	18,019	14,383	4,164	18,547	13,972	369	50,907	949	309	52,165	5,674	57,712	10.9%	57,382	52,089
F2015	17,162	14,437	4,227	18,664	14,055	369	50,249	966	306	51,522	5,447	55,807	10.6%	55,478	51,449
F2016	17,269	14,288	4,148	18,436	13,698	392	49,795	971	309	51,075	5,545	56,525	10.9%	56,198	51,006
F2017	17,989	14,572	4,275	18,847	13,106	381	50,323	1,053	319	51,695	5,198	56,893	10.1%	56,564	51,625
F2018	18,148	14,539	4,364	18,903	13,513	382	50,946	1,016	313	52,276	5,566	57,842	10.6%	57,527	52,202
Forecast															
F2019[4]	18,198	14,568	4,390	18,958	13,856	406	51,418	961	312	52,691	5,302	57,993	10.1%	57,671	52,594
F2020	18,253	14,484	4,487	18,971	14,702	491	52,417	1,012	312	53,741	5,382	59,124	10.0%	58,796	53,561
F2021	18,324	14,352	4,683	19,036	14,243	500	52,102	1,027	312	53,441	5,368	58,809	10.0%	58,480	53,253
F2022	18,411	14,244	4,688	18,931	14,066	501	51,909	1,056	314	53,279	5,356	58,634	10.1%	58,269	53,090
F2023	18,551	14,113	4,697	18,810	14,371	428	52,160	1,076	312	53,548	5,372	58,920	10.0%	58,554	53,434
F2024	18,709	14,034	4,697	18,731	15,414	389	53,243	1,071	312	54,627	5,449	60,076	10.0%	59,710	54,552
Actual 5yr Growth[5]															
F13-F18	0.3%	0.3%	1.8%	0.7%	0.0%	0.9%	0.4%	5.0%	0.1%	0.4%	4.3%	0.4%	3.9%	0.4%	0.4%
Fcst 5yr Growth[5]															
F18-F23	0.4%	-0.6%	1.5%	-0.1%	1.2%	2.3%	0.5%	1.1%	-0.1%	0.5%	-0.7%	0.4%	-1.2%	0.4%	0.5%

Notes:

1 Forecasts in table above includes all load reductions from rate impacts, DSM savings and loss reductions.
2 Light Industrial/Commercial is the sum of the loads in the light industrial sector and commercial sector.
3 Domestic sales equals total firm sales less sales to BC Hydro own use.
4 Forecast for fiscal 2019 does not include actuals sales over the first six months of fiscal 2019
5 Growth rates are computed over a five year period on an annual compound growth basis.

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix P

Load Forecast Internal Audit

SUMMARY AUDIT REPORT

CORPORATE AFFAIRS BUSINESS GROUP

LOAD FORECASTING AUDIT

Q1 F2018

AUGUST 28TH 2017

AU1803CAHR

Prepared By:

GDS Associates Inc.
J. Chong
R. Prinja
A. Lagnado

Distributed To: **J. Rich**
R. Reimann
J. Fraser
C. Yaremko
C. O'Riley
Audit & Finance Committee

Load Forecasting Audit F2018

AUDIT TYPE	AUDIT RATING
RISK BASED AUDIT	G

Legend:

Minor issues and impacts identified

Critical issues and impacts identified

Audit Objective

- Review the load forecasting process to ensure timely and reliable energy and peak demand forecasts which supports operational, financial and strategic planning at BC Hydro.
- This audit was conducted in conformance with the International Standards for the Professional Practice of Internal Auditing.

Background

- Load forecasting is essential for long-term planning, medium-term investment, and short-term operational activities. The load forecast is the starting point for many BC Hydro planning and operational activities and is an integral part of applications to the British Columbia Utilities Commission (BCUC).
  - Key internal users of the load forecast include Finance (financial modelling, planning), Generation (system optimization, winter peak planning), Transmission and Distribution (planning, investment), and Regulatory (rate designs, regulatory filings).
  - BC Hydro's total energy requirements, including losses and sales to other utilities and non-integrated areas, were 56,240 gigawatt hours in F2016.
- The Load Forecast group within the Corporate Affairs business group prepares the annual load forecast, and monitors and reports variances between forecast and actual load.
  - Key process activities include data collection and analysis, reviewing key assumptions and input parameters, reviewing outputs from various models, and performing scenario analysis.
- The load forecast covers a 20-year period and has two parts; an energy sales forecast measured in gigawatt hours, and a peak demand forecast measured in megawatts.
  - The energy sales forecast is a projection of annual total electricity demand. Key factors that influence the forecast include housing starts, appliance efficiency standards, residential electricity use-rates, gross domestic product, employment and weather.
  - The peak demand forecast is an estimate of maximum expected one-hour demand during the year based on normalized weather conditions.
- Load forecasting is a complex process and has been subject to a number of reviews by various parties including BC Hydro Audit Services (2007), BC Government (2011), and an external Consultant (2014). The BCUC has also commented on the process in past years in various regulatory applications.
- This audit was selected for inclusion in the F2018-2019 Audit Plan as load forecast risk has been identified as one of the top strategic enterprise risks. Load forecast risk is defined as a significant inaccuracy in estimating future loads.
- The Audit Services team was supplemented by a subject matter expert from GDS Associates Inc., a US based firm with extensive experience with load forecasting in the electrical utility industry.
  - The subject matter expert is a principal at GDS Associates Inc. with over 30 years of load forecasting experience including preparing load forecasts for various utility clients (ranging from day ahead to annual long-term horizons), and filing testimony on issues relating to load forecasting and other statistical analyses.

Load Forecasting Audit F2018

Key Findings

Overall Summary

- Overall, the load forecasting function at BC Hydro compares favorably to industry standards and to other large electric utilities in North America. No critical weaknesses were found.
- Load forecasting methodologies are consistent with best practices and load forecast outputs are provided to users and stakeholders on a timely basis.
- The greatest risk of load forecasting inaccuracy falls on the industrial class and is due to the uncertainty of future economic activity at the global, domestic, and service area levels, and the volatility of many individual customer loads.
- Areas identified for improvement primarily relate to making adjustments to forecast models and inputs to enhance overall forecast accuracy.

Governance

- Oversight structure of the load forecasting function is well-defined with various levels of management review and approval. The Load Forecast group is comprised of qualified staff with relevant educational background and work experience. Processes are in place for the development of a timely and reliable load forecast.
  - Based on the current scope of activities and outputs, the subject matter expert indicated that additional staff members should be considered to assist with the preparation of forecasts for the industrial class sector, data analysis, and to minimize employee succession risk.
- Appropriate objectives for the Load Forecast group have been established and include providing timely and reliable energy and peak demand forecasts, cross-training of staff, and performing continual process review.
- Management recognizes the importance of risk management and continues to mitigate load forecasting risks to the extent possible. Improved information flow between the Load Forecast team and other groups (Key Account Management, forecast users, the Executive Team) could be useful in mitigation efforts.
  - Key risks associated with load forecasting include process, methodology, key assumptions, employee succession, and regulatory.
  - Key risk mitigation activities include periodic external review of load forecasting models to reduce methodology risks; use of industry benchmark surveys, external sector experts and subscriptions for market research to reduce key assumptions risks.

Forecast Methodology

Specific Methodologies

- Statistically adjusted end-use models, which are considered industry best practice, are used to forecast energy sales for the residential and commercial customer classifications. Models are periodically reviewed by an external modelling consultant for continuous improvements.
  - Recent April 2017 industry benchmark survey of 75 electric and gas utilities in North America highlights that 57% and 54% of participants use these models to forecast sales for residential and commercial classes respectively.
- Primary forecasting methodology for the industrial class is to develop individual customer forecasts within each sector derived as the product of three inputs: facility production, electricity intensity and the percent load supplied by BC Hydro (probability weighting). Inputs for these components are

Load Forecasting Audit F2018

based on information from Key Account Managers, external consultants and industry subscription services.

- This methodology is preferred to other methods as it provides greater flexibility to quantify relevant factors for the sector and individual customer energy sales. It also provides greater detail for tracking and explaining forecast variances.

- The Load Forecast group prepares high and low forecast scenarios using a Monte Carlo simulation model at a total system level to address load forecast uncertainty. Simulation analysis is the best approach for developing the high and low forecast scenarios since it is statistically based and can include multiple input variables.
- While no critical weaknesses were identified, a number of technical recommendations related to model inputs were provided to Management to enhance forecast accuracy. Key recommendations relate to appliance stock and efficiency inputs, and elasticity assumptions.
  - Appliance stock and efficiencies are two critical inputs for the residential and commercial forecast models. Projections for these inputs are based on U.S. data and not specific to BC Hydro service regions. An internal prototype model to address this is under development.
  - Changes in energy sales due to changes in electricity price, household size and income, employment, gross domestic product, and retail sales are quantified in development of the residential and commercial forecasts (through elasticity coefficients). The coefficients should be reviewed and updated as the relationship between these variables and energy consumption has most likely changed over time.

Demand Side Management Integration

- Demand Side Management impacts on the Load Forecast are accounted for as a post-modelling adjustment developed by the Conservation and Energy Management group. According to the subject matter expert, this is the best approach and consistent with industry benchmark surveys.

Developing Industries

- The load forecasting process adequately accounts for growth and impacts associated with electric vehicles as a post-modeling adjustment. Given the relatively immature market and the uncertainty surrounding electric vehicle adoption in future years, analyzing and projecting vehicle electricity consumption as a stand-alone component is appropriate.

- The Load Forecast group's approach of including energy and peak demand only for known liquefied natural gas customers and known electrification projects in the base case forecast is appropriate. The base case load forecast includes energy and peak demand only for liquefied natural gas customers that have requested electric service from BC Hydro.

Forecast Variance

- Review of prior load forecasts reveal that forecast variances for the residential and commercial classifications are within a range of expectancy based on industry benchmarks developed by Itron Inc. and the US Energy Information Administration.
- Variances for the industrial class are higher than those for the residential and commercial classes. This is expected given the volatility of loads and the uncertainties of future economic activity in the forestry, oil and gas, and mining sectors, which comprise the significant portion of total energy sales for the industrial class.
  - Large industrial customers comprise less than 1% of total customers, but nearly 24% of total domestic sales.

Load Forecasting Audit F2018

Outputs and Reporting

- The Load Forecast group provides the needed forecast outputs and supporting documentation to users on a timely basis. Providing the long-term forecast once a year is sufficient for long-term planning.
  - Key outputs include: the annual Service Plan Forecast which is a preliminary forecast with a 10-year horizon prepared in October; the annual Long-Term Forecast prepared in December which covers a 20-year forecast horizon, and reflects any adjustments made to the forecast between October and December.
  - Variance reports are distributed to user groups monthly providing high-level reasons for forecast variances.

Management Comments and Action Plans

- Management agrees with the recommendations in the audit report and will address the majority of recommendations by August 2018. The remaining recommendations, which require some planning and research time, will be implemented by December 2018.

MANAGEMENT AUDIT REPORT

CORPORATE AFFAIRS BUSINESS GROUP

LOAD FORECASTING AUDIT

Q1 F2018

AUGUST 28TH 2017

AU1803CAHR

Prepared By:

GDS Associates Inc.
J. Chong
R. Prinja
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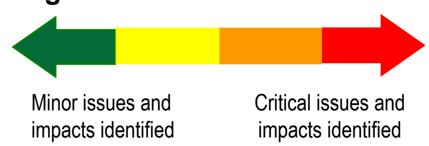
Distributed To:	**J. Rich**
	R. Reimann
	J. Fraser
	C. Yaremko
	C. O'Riley

Load Forecasting Audit F2018

CONTENTS

AUDIT	TYPE	RATING
1. LOAD FORECASTING AUDIT 	RISK BASED AUDIT	G

Legend:



Load Forecasting Audit F2018

1a. Executive Summary

- For each audit, Audit Services provides two separate Audit Reports. The first report is a Summary Audit Report prepared for Senior Management and the Audit & Finance Committee (AFC) of the Board. This Management Audit Report provides additional information and related audit recommendations for management purposes and will not be presented to the AFC.
- Management should also refer to the Summary Audit Report for high level conclusions and findings.

1b. Background

- Load forecasting is essential for long-term planning, medium-term investment, and short-term operational activities. The load forecast is the starting point for many BC Hydro planning and operational activities and is an integral part of applications to the British Columbia Utilities Commission (BCUC).
  - Key internal users of the load forecast include Finance (financial modelling, planning), Generation (system optimization, winter peak planning), Transmission and Distribution (planning, investment), and Regulatory (rate designs, regulatory filings).
  - BC Hydro's total energy requirements, including losses and sales to other utilities and non-integrated areas, were 56,240 gigawatt hours in F2016.
- The Load Forecast group within the Corporate Affairs business group prepares the annual load forecast and monitors and report variances between forecast and actual load.
  - Key process activities include data collection and analysis, reviewing key assumptions and input parameters, reviewing outputs from various models, and performing scenario analysis.
- The load forecast covers a 20-year period and has two parts, an energy sales forecast, measured in gigawatt hours and a peak demand forecast, measured in megawatts.
  - The energy sales forecast is a projection of annual total electricity demand. Key factors that influence the forecast include housing starts, appliance efficiency standards, residential electricity use-rates, gross domestic product, employment and weather.
  - The peak demand forecast is a projection of maximum expected one-hour demand during the year based on normalized weather conditions.
- Load forecasting is a complex process and has been subject to a number of reviews by various parties including BC Hydro Audit Services (2007), BC Government (2011), and an external Consultant (2014). The BCUC has also commented on the process in past years in various regulatory applications.
- This audit was selected for inclusion in the F2018-2019 Audit Plan as load forecast risk has been identified as one of the top strategic enterprise risks. Load forecast risk is defined as a significant inaccuracy in estimating future loads.
- The Audit Services team was supplemented by a subject matter expert from GDS Associates Inc., a US based firm with extensive experience with load forecasting in the electrical utility industry.
  - The subject matter expert is a principal at GDS Associates Inc. with over 30 years of load forecasting experience including preparing load forecasts for various utility clients (ranging from day ahead to annual long-term horizons), and filing testimony on issues relating to load forecasting and other statistical analyses.

Load Forecasting Audit F2018

1c. Audit Objective and Scope

Objective

- Review the load forecasting process to ensure timely and reliable energy and peak demand forecasts which supports operational, financial and strategic planning at BC Hydro.

Scope

- With the assistance of a load forecasting subject matter expert, the audit focused on the following areas:
  - **Governance** - structure, oversight, resources, process, risk management
  - **Forecast Methodology** - models, inputs, assumptions, methodologies, variance analysis
  - **Outputs & Reporting** – energy load and peak forecasts, forecast updates
- Integration of Demand Side Management Plans and Load Forecasts was also reviewed.
- This audit was conducted in conformance with the International Standards for the Professional Practice of Internal Auditing.

Load Forecasting Audit F2018

1d. Findings, Recommendations and Management Action Plans

Summary

Overall, the load forecasting function at BC Hydro compares favorably to industry standards and to other large electric utilities in North America. No critical weaknesses were found.

Load forecasting methodologies are consistent with best practices and load forecast outputs are provided to users and stakeholders on a timely basis.

The greatest risk of load forecasting inaccuracy falls on the industrial class and is due to the uncertainty of future economic activity and the volatility of many individual customer loads.

Areas for improvement identified primarily relate to making adjustments to forecast models and inputs to enhance overall forecast accuracy.

Governance

Overall Conclusion

A well-defined oversight and management structure has been established with appropriate departmental objectives in place. Adequacy of current resourcing levels should be reviewed and detailed procedural documentation is required to enhance transparency and staff cross-training.

Key Conclusions and Findings

This section focuses primarily on oversight, resources, objectives, and risk management.

Oversight and Resources

- Oversight structure over the load forecasting function is well-defined with various levels of management review and approval. Manager of Load Forecast reports to the Director of Energy Planning, who reports to the Senior Vice President Corporate Affairs.
  - Director of Energy Planning holds regular bi-weekly meetings with his departments to share ideas, questions and concerns. This provides a high level of interaction and communication among all energy planners, which in turn increases overall planning efficiency.
  - The Annual Load Forecast is reviewed by the Director of Energy Planning, the Senior Vice President Corporate Affairs, and members of the Executive Team before presentation to the Board of Directors.
- The Load Forecast group is comprised of qualified staff with relevant educational background and work experience. The current team is comprised of a manager, a senior forecaster, and 3.5 full-time equivalent forecasters. Work experience for the team ranges from 4 to 25 years, with educational backgrounds in economics, finance, engineering and mathematics.
  - Based on the current scope of activities and outputs, the subject matter expert indicated that additional staff members should be considered to assist with the preparation of forecasts for the industrial class sectors, analysis of high volume of data, preparation of documents for regulatory hearings, and to minimize employee succession risk.

Load Forecasting Audit F2018

Objectives

- Appropriate objectives for the Load Forecast group have been established and are being achieved. These include providing timely and reliable energy and peak demand forecasts, cross-training of staff, and performing continual process review.
  - Continual process review involves Management and peer review of load forecast methodologies and related processes for the residential, commercial and industrial customer classifications. Several noteworthy research initiatives (discussed in the Methodology section) were in progress that will enhance overall accuracy.

Processes

- Processes are in place for the development of a timely and reliable load forecast. A schedule for completing all aspects of the Annual Load Forecast has also been developed and communicated by the Manager of Load Forecast to all core forecast users.
  - Load forecasting processes include: data collection, database updates, data review and analysis, development of key assumptions impacting future electricity consumption, forecast model development or updates, forecast development, and managerial and executive review.
- Process flow charts have been created to present a high-level description of steps taken to complete various load forecasting tasks; however, more detailed descriptions for each step would provide more complete information for forecast users and new staff.

Risk Management

- Key risks associated with load forecasting include process, methodology, key assumptions, employee succession, and regulatory.
  - Process risk occurs when a key process is neglected that could negatively impact the reliability of the forecast. Methodology risk occurs when improper or outdated methods are used to develop the forecast. Key assumptions risk occurs when information used to develop industrial or economic activity assumptions over a forecast horizon is not reliable or outdated. Such problems increase the likelihood of forecast inaccuracies.
  - Employee succession risk occurs when a key load forecaster leaves the Company without any succession plans or staff training documentation in place. Regulatory risk occurs when BC Hydro does not meet minimum filing requirements or when filed applications are denied.
- Management recognizes the importance of risk management and continues to mitigate load forecasting risks to the extent possible. Improved information flow between Load Forecast and other groups (Key Account Management, forecast users, the Executive Team) could be useful in mitigation efforts.
  - Key risk mitigation activities include periodic external review of load forecasting models to reduce methodology risks; use of industry benchmark surveys, external sector experts and subscriptions for market research to reduce key assumptions risks.
  - An internal dashboard that presents key metrics and risk indicators would provide stakeholders and core users with current information. Increased awareness and communication between Load Forecast Management, staff, and Key Account Managers could improve overall forecast accuracy.

Load Forecasting Audit F2018

	Recommendations	Management Action Plans
	Governance	
1	❑ Review adequacy of existing resources and consider increases to current staffing level.	❑ Director of Energy Planning will provide resourcing recommendations on staffing, as well as consulting and subscription services to Senior VP Corporate Affairs by December 31, 2017. ◆ Ability to address the majority of the recommendations is contingent upon staffing levels.
2	❑ Prepare load forecasting detailed procedural documentation to supplement the high-level process documentation.	❑ Documentation will be completed by March 30, 2018 as part of the F2019 load forecast cycle.
3	❑ Consider developing a dashboard to highlight key information and current assumptions/outlook that impact the load forecast.	❑ Work has already starting in this area and Load Forecast will work with other groups such as Key Account Management and Finance groups to finalize format and content by December 31, 2017.

Forecast Methodology

Overall Conclusion

Methodologies consistent with industry best practices are used to develop the energy sales forecast. Historical forecast variances for the residential and commercial classifications are lower than industry benchmarks, while variances for the industrial class have been more volatile.

Key improvement areas to further improve forecast accuracy include completion of the stock and flow model development and the update of elasticity coefficients.

Key Conclusions and Findings

General Forecast Approach

- The energy sales forecast is developed using a bottom-up approach and in line with best practices. Forecasts are developed separately for the residential, commercial, and industrial classes. Most electric utilities in North America follow a bottom-up approach as it provides for greater explanatory power in developing and explaining the forecast and its driving influences.
  - The industrial class is further broken down by sector (Forestry, Oil and Gas, Mining, and Other), which provides the means for capturing sector specific factors. Similar to other electric utilities, BC Hydro also forecasts their largest industrial customers on an individual basis.

Load Forecasting Audit F2018

Specific Methodologies

Residential

- Residential energy sales are projected for each of BC Hydro's four customer service areas (Lower Mainland, Vancouver Island, South Interior and Northern Region). The forecast is computed as the product of the projected number of residential customers and average kilowatt hour use per customer.

- Forecast number of customers is based on projected housing starts and dwellings by housing types which are provided by an external economic consultant.

- Statistically adjusted end-use (SAE) models, which are considered industry best practice, are used to forecast average residential use per customer account for each of the four customer service regions.
  - A recent benchmark survey from Itron Inc. (Itron) highlights that 57% of electric and natural gas utilities in North America use SAE models to analyze and forecast long-term residential sales, 33% use econometric models, and 10% use other methods.
    - Itron provides consulting services in multiple areas, including load forecasting, to utilities across the world. They periodically survey utilities across North America to develop load forecasting benchmarks.
- SAE models provide the means for quantifying the impacts of multiple driver variables, including economic drivers, housing and building characteristics, appliance saturations and efficiencies, and weather. This method provides load forecasters detailed information to better explain historical electricity sales trends and variances from projected sales.
  - The SAE models produce monthly projections which provide the outputs needed for the development of monthly and annual forecasts for up to 21 years.

Commercial

- For the four planning regions, SAE models are developed to project sales by two commercial groups (less than or equal to 35 kw, and greater than 35 kw). Similar to the residential model, the commercial SAE models produce monthly projections, which provide the outputs needed for the development of monthly and annual forecasts for up to 21 years.
- The subject matter expert and industry surveys support the use of the SAE methodology as the best approach for modeling commercial sales. A recent Itron industry benchmark shows that 54% of reporting utilities use SAE models to forecast long-term commercial sales, 38% use econometric models, and 8% use other methods.

Light Industrial (Distribution)

- Light Industrial sales are the sum of sales for coal, wood, oil and gas and other industrial loads connected at the distribution level. Loads for the coal, wood, and oil and gas sectors are developed using the same methodology as the Large Industrial class (discussed in the next section).
- An econometric model is used to forecast the other customer categories within the light industrial energy sales. The primary economic driver variable is regional gross domestic product (GDP).
- The methods used to forecast energy sales for the Light Industrial class are appropriate. Enhancements can be made to the econometric model used to forecast the other customer category as it does not quantify the impacts of heating, ventilation, and air conditioning equipment (HVAC) or motor efficiencies.

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- The relationship between energy sales and GDP has most likely changed in recent years to reflect lower energy intensity (energy sales per GDP) due to continued increases in average end-use efficiencies and energy management systems.

Large Industrial (Transmission)

- BC Hydro currently has a large number of customers that make up the subsectors of Mining (coal and metal), Forestry (pulp and paper, wood, and chemical), and Oil and Gas (gas producers and processors, gas pipelines, oil pipelines, oil refineries, and liquefied natural gas).

- The general forecasting methodology is to develop individual customer forecasts within each sector derived as the product of three inputs: facility production, electricity intensity, and the percent load (probability weighting) supplied by BC Hydro. Inputs for the three forecast components are based on information obtained from BC Hydro's Key Account Managers, external consultants and subscription services.

- The methodology to forecast large industrial sales for transmission customers is preferred to other methods. It provides greater flexibility to quantify relevant factors for the sector and individual customer energy sales and peak demand. It also provides greater detail for tracking and explaining forecast variances.
  - A bottom-up methodology is used to forecast energy sales for the forestry and mining sectors. Forecasts are developed individually for each customer and aggregated to the sector levels.
  - A top/down, bottom/up methodology is used to forecast energy sales for the oil & gas sector. Top/down forecasts are prepared at the sector level and based on key input from external service providers and sector-specific consultants that provide commodity price forecasts and sector-specific outlooks.
    - The top/down and bottom/up analyses are iterated until results from the two approaches converge.
- The forecast approach is dependent upon detailed and reliable information from external sources and internal key account managers. BC Hydro has established procedures and schedules for obtaining that information.

- The sector-specific industrial models for forestry, oil and gas, and mining are prepared in Excel spreadsheets. Clarity and interpretation of spreadsheet formulas can be difficult for persons other than the model developer. More detailed process documentation would provide for greater transparency and clarification.
  - Further efforts should be taken to identify areas where the process could be streamlined as Load Forecast staff indicated that maintaining the individual customer models is time consuming.

Model Reviews

- SAE models are periodically reviewed by BC Hydro's modelling consultant (Itron) for continuous improvements. External model reviews help to improve the overall reliability of BC Hydro's forecasting models and results. This process also allows Load Forecast staff to leverage the modeling expertise of Itron, as well as discuss industry trends and how best to capture them in the modeling process.

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Forecast Scenarios

- To address load forecast uncertainty, Load Forecast group prepares high and low forecast scenarios at the system level using a Monte Carlo simulation model, which produces a probability distribution of forecast outcomes used to develop the forecast ranges. The process is well documented in the 2012 Electric Load Forecast.

- Simulation analysis is the best approach for developing the high and low forecast scenarios since it is statistically based, can include multiple input variables, and produces a probabilistic forecast based on input probability distributions. However, GDP is not the best model input to represent the residential and commercial classes.
  - Load Forecast group includes GDP as a driver variable of residential and commercial energy sales; however, the relationship between GDP and energy sales has changed considerably in recent years according to Itron's 2016 Forecasting Benchmark Study. The predominant influence on sales for these two classes may now be the number of customers.

Forecast Variance

- Review of prior load forecasts reveal that forecast variances for the residential and commercial classifications are within a range of expectancy based on industry benchmarks developed by Itron and the US Energy Information Administration (EIA). The following table compares BC Hydro forecast variances to industry benchmarks.
  - EIA collects, analyzes, and disseminates independent and impartial energy information, including electric load forecasts at the international, national, and regional levels.

Comparison of BC Hydro Forecast Variances to Industry Benchmarks[1]

Forecast Period	Class	BC Hydro	EIA	Itron
1 yr. out	Residential	1.0%	1.9%	1.7%
3 yr. out	Residential	1.3%	3.9%	na
6 yr. out	Residential	4.6%	8.2%	na
1 yr. out	Commercial	0.9%	1.2%	1.7%
3 yr. out	Commercial	1.8%	2.3%	na
6 yr. out	Commercial	2.3%	8.2%	na
1 yr. out	Industrial	1.3%	1.9%	3.5%
3 yr. out	Industrial	9.5%	6.2%	na
6 yr. out	Industrial	19.6%	11.4%	na

- Variances are low for the residential and commercial classifications and fall below industry benchmarks. As a result, no changes to the methodology used to forecast energy sales for these two classes are required based on subject matter expert's assessment.

[1] Reported variances represent the average of mean absolute percent errors (MAPE). MAPE measures the size of the forecast error in percentage terms and is calculated as the average of the unsigned percentage error.

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- Residential class: For the eight forecasts developed in F2008 through F2015, the average variance between actual and weather adjusted energy sales is 1.0% for the first forecast year, 1.3% for three years out and 4.6% for six years out.

- Commercial class: The average variance between actual and weather adjusted energy sales is 0.9% for the first forecast year, 1.8% for three years out, and 2.3% for six years out.

- Variances for the industrial class are higher than those for the residential and commercial classes. This is expected given the volatility of loads and the uncertainties of future economic activity in the forestry, oil and gas, and mining sectors, which comprise the significant portion of total energy sales for the industrial class. Large industrial customers comprise less than 1% of total customers, but nearly 24% of total domestic sales.

  - The greatest risk identified during the audit is potential forecast inaccuracies pertaining to the industrial class and corresponding to the uncertainty of future load economic activity at the global, domestic, and service area levels. Many industrial customer loads are quite volatile given the relative uncertainty of economic activity (e.g., one or two years out), and therefore cannot be modeled or forecasted with a high degree of accuracy.

  - While the forecast variance for the Industrial class is higher than industry benchmarks beyond the first-year period, BC Hydro should continue with the same forecast methodologies.

Economic / Industry Outlooks and Market Research

Economic Outlook

- Economic outlooks obtained from external economic consultant exceed industry standards in providing reliable inputs for the residential, commercial, and light industrial forecasting models. While no benchmarks are available for comparative purposes, the outputs provided by the consultant exceed what the subject matter expert is accustomed to seeing for electric utilities in North America.
  - The economic outlook is obtained annually and contains forecasts and discussions broken down by the four customer service areas.
    - Area forecasts are constructed using regional macroeconomic models, assumptions concerning the economic performance of BC's major trading partners, commodity prices, interest rates, exchange rates, fiscal policy, information on future major projects, and input from BC Hydro staff.
  - To further improve forecast accuracy, Management could request a review and reconciliation of prior economic projections and actual data. This could be useful to Load Forecast staff in analyzing and explaining load forecast variances.

Industrial Sector Outlook

- Load Forecast group collects high quality, sector-specific industrial data for development of their industrial energy forecast. These include subscriptions to multiple sources of commodity price forecasts and consulting services of sector-specific experts.

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- Data from each source is not always updated annually due to budget constraints. The commodity price and sector-specific outlooks are critical inputs for the development of the large industrial energy sales forecasts.

- To further improve forecast accuracy, consultants could provide explanations and/or reasons for the variances between industry outlooks once actual or estimated data becomes available.

Market Research

- Load Forecast group follows industry best practices in obtaining service area specific data that is otherwise not available. Similar to other large electric utilities in North America, BC Hydro conducts residential surveys every two years, while commercial surveys are conducted on a less frequent basis.

  - Surveys are performed to collect data on building characteristics and appliance stock, which is used to develop inputs for the residential and commercial forecasting models. Residential surveys may be conducted every three years instead if the key housing and appliance market share trends are not changing significantly over time to achieve potential cost savings.

Specific Input Assumptions

Appliance stock and efficiencies

- Appliance stock and efficiencies are two critical inputs for the residential and commercial forecast models. However, projections for these inputs are based on the U.S. Pacific Region (developed by Itron) and not specific to BC Hydro service regions. An internal prototype model ("stock and flow") is under development to address this issue.

  - The prototype model would establish a single (historic) baseline and forecast assumptions on natural growth, natural conservation, impact of codes and standards on minimum efficiency requirements, average stock efficiency and saturations of various residential end uses.

  - The prototype model is at its early stage and work needs to be accelerated. The availability of data corresponding to BC Hydro's service area may increase overall forecasting accuracy.

Elasticity Coefficients

- Elasticity coefficients for energy consumption with respect to electricity price, household income, household size, employment, commercial GDP, and retail sales are all quantified in development of the residential and commercial class energy sales forecasts. However, the coefficients should be reviewed as the relationship between these variables and energy consumption has mostly likely changed over time.

  - Current price elasticity coefficients are based on a 2007 external study. Other elasticities are based on default values provided by Itron in the residential and commercial SAE models. An internal price elasticity study is currently in progress to update the coefficients however progress needs to be accelerated.

  - In response to directives made by the BCUC, BC Hydro applies the price elasticity coefficient as a post-modeling adjustment to report the energy sales.

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Peak Demand

- Peak demand, known as the highest hourly load measured over a defined period, is a comprehensive, iterative process between the Load Forecast group and Distribution Area Planning group.

- The current process of forecasting peak demand is comprehensive and incorporates best practice methodologies. The process involves Area Planners' expertise on expected near-term changes in load for 220 substations, and Load Forecasters modeling expertise and oversight in maintaining consistency between the energy and peak demand forecasts.

Weather Normalization

- Load Forecast group uses regression analysis to weather normalize energy sales. The technique is common among electric utilities and has been accepted as the best practice by many regulatory entities across North America.

- Weather normalization refers to the practice of estimating actual energy sales under normal, or average, weather conditions. Load Forecast group computes normal degree days on a rolling 10-year average. There is no clear consensus among utilities in North America regarding the number of years upon which to calculate normal degree days.

  - Itron benchmark information shows that 22% of participants base normal degree days on a 10-year or less average, 32% base on a 30-year average, 26% base on a 20-year average, and the remaining 20% base on other periods.

- The weather normalization process for residential sales is based on a statistically sound regression model; however, a more transparent and simpler model would separate the impacts of heating and cooling degree days. If air conditioning load continues to increase, establishing two separate parameters will provide more detailed information on their respective impacts.

  - Most utilities in North America separate heating and cooling impacts when weather normalizing energy sales.

  - An additional area for improvement is to ensure actual sales for the commercial sector are weather normalized when performing monthly variance analysis, similar to the residential sector.

Demand Side Management (DSM) Integration

Integration Approach

- The method used by Load Forecast group to account for DSM impacts is the best approach, as it uses post-modeling adjustments developed by Conservation and Energy Management (C&EM) group. Use of an alternative method would more than likely produce results that are inconsistent with, and not as fully developed as those provided internally.

  - The load forecast includes the impacts of existing and future DSM programs. The impacts associated with participants in existing programs are reflected in the historical electricity sales data in the residential and commercial forecasting models.

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- The impacts associated with future participants in existing programs and all participants in future programs are reflected in the forecast as a post-modeling adjustment.

- The 2013 Itron survey shows that 38% of 72 reporting utilities account for DSM impacts through post-modeling adjustments. 22% through estimating the forecasting model with historical DSM net of past and future DSM savings, 11% through the SAE model specification, and 29% through other methods.

Overlap of Codes and Standards

- Impacts associated with the overlap of codes and standards between the Load Forecast and DSM plan are reasonably accounted for in the Load Forecast.

  - An analysis performed by the Load Forecast and C&EM groups identified areas of codes and standards overlap. Beginning with the 2010 Electric Load Forecast, energy sales and peak demand projections reflect adjustments to address the overlap and potential double counting of DSM impacts.

Developing Industries

Electric Vehicles (EVs)

- Load forecasting process adequately accounts for growth and impacts associated with EVs as a post-modeling adjustment since the 2010 Electric Load Forecast. Given the relatively immature market and the uncertainty surrounding EV adoption in future years, analyzing and projecting EV electricity consumption as a stand-alone component is appropriate.

  - Electricity consumption for EVs currently comprises less than 1% of total retail sales and is projected to comprise just over 2% by F2036. Itron's 2016 Forecasting Benchmark Survey highlights that 55% of all reporting utilities include EVs in their load forecasts.

Liquefied Natural Gas (LNG)

- Load Forecast group's approach of including energy and peak demand only for known LNG customers in the base case forecast is appropriate. The LNG sector has not yet been developed, and the uncertainty surrounding future growth in sales is high due to global competition.

  - BC Hydro's 2016 base case forecast includes electric sales to LNG customers beginning in F2017. The base case load forecast includes energy and peak demand only for LNG customers that have requested electric service from BC Hydro.

Electrification

- BC Hydro's current process of including energy demand from known electrification projects in the base case forecast is appropriate. The 2016 Load Forecast does not include potential increases in energy and peak demand associated with BC Hydro electrification efforts.

  - Future demand associated with electrification will largely depend on greenhouse gas related legislation, City of Vancouver electrification initiatives, and future industrial related activity.

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	Recommendations	Management Action Plans
	Methodology	
4	**Light Industrial** ❑ Review and update the light industrial econometric model to quantify the impacts of HVAC and motor efficiencies. ❑ Consider a model parameter reflecting the implementation of energy management systems.	❑ Load Forecast group will review possible methodology change in collaboration with Conservation and Energy Management group. Any changes will be implemented by August 31, 2018 in time for inclusion in the F2019 load forecast cycle.
5	**Large Industrial** ❑ Review existing processes and consider streamlining opportunities such as automation of spreadsheets and develop process documentation.	❑ Documentation to be completed by February 28, 2018 prior to the start of the F2019 load forecast cycle. ❑ Load Forecast group will have discussions with the Information Technology group to identify processes that can be automated. Identification will be completed by April 30, 2018 with implementation by August 31, 2018.
6	**Forecast Scenarios** ❑ Review and replace the GDP parameter in the Monte Carlo model used to simulate energy sales with number of customers.	❑ Management needs to verify underlying assumption. ◆ This could entail significant work for both system and regional (distribution planning) high low bands. ❑ If required, a methodology change will be recommended by October 31, 2018 to run parallel with existing Monte Carlo model as part of the F2019 load forecast cycle.
7	**Economic / Industrial Outlooks** ❑ Request industrial and economic consultants to provide explanations and/or reasons for the variances between outlooks provided and actual output once actual or estimated data becomes available.	❑ Variance explanations will be included in future consultant reports, beginning with those developed to support the F2019 load forecast cycle.
8	**Market Research** ❑ Consider conducting residential customer surveys once every three years if the key trends being measured are not changing significantly over time.	❑ Load Forecast group will discuss the recommendation with Conservation and Energy Management and advise Senior VP Corporate Affairs by December 30, 2018. ◆ With evolving electrification loads and advancing energy efficiency participation, biannual may still be required.

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	Recommendations	Management Action Plans
		◆ There may be other survey users which require maintaining the current survey frequency. Discussions to include commercial end-use survey as well as residential end-use survey.
9	**Specific Input Assumptions** ❑ Accelerate internal studies / development on: ◆ The stock and flow model. ◆ Elasticity coefficients updates used in the development of the load forecast.	❑ Stock and Flow: Tentative schedule to have fully functional model to run in parallel with the SAE model by November 30, 2018 as part of F2019 load forecast cycle. ◆ Load Forecast group will confirm timeline, scope and resource requirements with project manager. This will likely require additional resources to support input verification and possible software development. ❑ Price Elasticity Coefficients: Load Forecast group in collaboration with other groups will develop a study scope on price elasticity by August 30 2018. Study to be completed in Fiscal 2019 subject to funding approval. ❑ SAE Model Elasticity Coefficients: SAE model coefficients to be reviewed with model vendor (Itron) by March 30, 2018. Itron recommendations and testing by the Load Forecast group to be completed by August 30, 2018 in time for inclusion in the F2019 load forecast cycle.
10	**Weather Normalization** ❑ Consider updating the specification for the model used to weather normalizes residential sales to separate the impacts of heating and cooling. ❑ Update the monthly forecast variance process to include weather normalized energy sales for the commercial classification.	❑ Weather normalization: Load Forecast group will review possible methodology change in collaboration with model vendor (Itron). Any change will be implemented by August 30, 2018 in time to be included in F2019 load forecast cycle. ❑ Monthly Variance: Load Forecast group will collaborate with Customer and Energy Analytics group to confirm data availability. Tentative schedule, subject to data availability, is to include weather normalized sales for the commercial sector by March 30, 2018.

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Outputs & Reporting

Overall Conclusion

Load Forecast group provides the needed forecast outputs and supporting documentation to users on a timely basis. Providing the long-term forecast once a year is sufficient for long-term planning.

Key Conclusions and Findings

- Key outputs include the following: The annual Service Plan Forecast which is a preliminary forecast with a 10-year horizon prepared in October; the annual Long-Term Forecast prepared in December which covers a 30-year forecast horizon, and reflects any adjustments made to the forecast between October and December. Variance reports are distributed to user groups monthly providing high-level reasons for forecast variances.

- Based on interviews with various user groups and review of relevant documentation, the subject matter expert believes that providing the long-term forecast once a year is sufficient for long-term planning. The needed outputs are provided to users in sufficient detail and are generally delivered on time. Memos were provided with the forecast to summarize highlights, changes from prior forecasts, and other information as requested.

- Management indicated that an on-line repository is being created for central retention of annual load forecasts and official planning studies. The Energy Planning Information Central site, when completed, will enable forecast users to easily identify the specific load forecast used to better support various studies and filings made with the BCUC.

	Recommendations	Management Action Plans
	Outputs & Reporting	
	None	None

BC Hydro
Power smart

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix Q

Elasticity Study and GDP Study

DNV·GL

Memo to:
BC Hydro

From: DNV GL
Date: 9/6/18

Subject: Memo - Price Elasticity Findings and Recommendations

1 PROJECT OVERVIEW

BC Hydro hired DNV GL to provide an external review of how BC Hydro applies price elasticity estimates in various business applications, including load forecasting and rate design. This memo provides DNV GL's findings and recommendations on this topic.

In this section, we provide a background discussion on price elasticity, details on project goals, and a description of DNV GL's approach. We discuss our research, findings, and recommendations in section 2. We outline a few next steps in section 3 and provide the sources used in the research in the final section.

1.1 Background

Price Elasticity

Price elasticity of demand measures the responsiveness of quantity demand to a change in price, and is expressed as the percent change in quantity to a one percent change in price. When looking at the demand for electricity, price elasticity can be broken down into two components: a short-run elasticity reflecting changes in utilization of a given stock of equipment, and a long-run elasticity reflecting both changes in utilization and changes in the composition and efficiency of the energy using equipment.

While the concept of price elasticity is simple, the estimation (and interpretation) of price elasticities in any industry can be complicated. Estimates can depend on the type of study (such as time-series[1] or cross-sectional[2]), the type of elasticity being measured (such as long-run versus short-run), and the customer group being studied (residential/commercial, in mild/severe climate and high/mid/low incomes, etc.). In areas where there are significant policies or programs directed at influencing consumption (such as codes and standards and energy efficiency rebate programs), the ability to separate out the effects of these policies/programs from pure price effects can be challenging.

Utilities apply various price elasticity of demand estimates in two separate load forecasting processes: long-run integrated resource planning (IRP) and short-run revenue requirements that are used to set rates utilities charge customers. Examples of challenges in estimating price elasticity include those that may arise due to variations in time-of-use of end-use equipment and differences in their distribution among customer groups. Time-of-use variations can occur because different end-uses operate at different times and elasticities can vary by end-use (e.g. space heating where the thermostat can change versus refrigeration where usage is mainly determined at the point of purchase). Different customer groups will have different distributions of end-uses and will also have different consumption patterns that can both affect overall price elasticities.

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[1] Time-series is a sequence of observations collected for a variable (such as energy consumption) at fixed intervals of time. For instance, monthly energy use over a period of several years is an example of time-series data.

[2] Cross-sectional data are observations collected for a variable across many subjects (such as individuals and firms) at a point in time. For istnance, energy use data collected for many different households at a given point in time is an example of cross-sectional data.

To complicate matters, price elasticities will inevitably change over time as consumption habits change and response options evolve. For example, increased automation may facilitate a larger response to short-run price signals, and the presence of more space heating efficiency options may facilitate a large long-run price response.

Given the above discussion, we see the price elasticity tool as more of a butcher knife than a scalpel. One should not expect high-accuracy price elasticity estimates to provide high-accuracy analytic results. Rather, one should look for reasonable price elasticity estimates that provide reasonable results.

1.2 Goals and Approach

The primary objective of this project was to determine if the price elasticity currently in use by BC Hydro in its business applications (including load forecasting and rate impact evaluation) is appropriate. To meet this objective, DNV GL undertook a literature review that focused on price elasticity in the utility context. DNV GL collaborated with BC Hydro to select 18 utilities in Canada and the United States to include in the literature review.[3] For the selected utilities, DNV GL concentrated its research on recent load forecast reports and documents such as Integrated Resource Plans (IRPs) and rate cases which often require the use of price elasticity to estimate the load impact of the rate change. In addition to the utility review, DNV GL researched academic documents focused on price elasticity, some of which were used as sources in various utility load forecast reports or rate cases. The goals of the literature review were to:

- Review and document elasticity estimates from jurisdictions and utilities like BC Hydro as well as recent academic studies on price elasticity
- Review BC Hydro's application of price elasticities in various business processes
- Identify the price elasticity estimates that best apply to BC Hydro
- If/where gaps are present, the review will also provide recommendations on how to bridge the gaps, including the development of targeted studies and/or the use of judgement based approaches

In addition to the primary elasticity review, BC Hydro was also interested in answers to several questions related to different aspects of price elasticities and their application, including:

DSM

- How does the presence of DSM affect price elasticity estimates over time (such as 20-year planning)?
- How does one identify pre-DSM plan and rate design elasticities when most utilities have both already included in their history?

Rate Structures and Customer Sectors/Segments

- Should elasticities be different depending on the rate structure to which they are assumed to apply (flat rate, time of use rate, tiered)?

[3] Same list of utilities as jurisdictional review included in 2015 BC Hydro rate design application.

- Does it make sense to apply elasticities to industrial sectors with few, large participants and where an assessment of future customer viability is already made based upon expert advice?
- What kind of behavioral and non-behavioral changes should be included in short-run and long-run elasticities of substitution (TOU rate)?
- What is the range of uncertainties on short-run and long-run elasticity of substitution (TOU rate) estimates?
- Under a TOU rate, how should consumption change during peak and off-peak hours be attributed to substitution (change consumption from peak to off-peak period) and change in demand (reduction in use during peak)?
- At what price, consumption, or other driver, do customers become inelastic?
- What is a reasonable substitution price elasticity, for customers and end uses for which natural gas is substitute for electricity?

Timing (long-run vs. short-run)

- How much difference is there between short-run and long-run elasticities and, given the rapidly changing world, how long should long-run elasticities be?
- What kind of behavioral and non-behavioral changes should be included in short-run and long-run elasticities of demand?
- What is the range of uncertainties on short-run and long-run elasticity of demand estimates?
- What are the differences in short-run and long-run elasticities of demand for residential customers by consumption level, region, heating fuel and dwelling type?

The overall objective of this project is to provide BC Hydro with recommendations on the appropriate price elasticities to use for various business purposes.

2 ELASTICITY

This section presents the elasticity findings and conclusions drawn from DNV GL's literature and jurisdictional review. In section 2.1 we briefly describe BC Hydro's current elasticity estimates and applications before presenting our findings from the literature and jurisdictional review in section 2.2. DNV GL presents its price elasticity analysis, conclusions and recommendations for BC Hydro in section 2.3.

2.1 BC Hydro - elasticity estimates and applications

For background information, DNV GL reviewed several documents provided by BC Hydro at the beginning of the project as well as additional documents that became available during the project, including:

- Direct testimony of Ren Orans in support of the 2008 Long-run Acquisition Plan
- Electric Load Forecast Fiscal 2013 to 2033
- Evaluation of the Large and Medium General Service Conservation Rates: F2014
- The jurisdictional review included in the 2015 Rate Design Application
- The load forecast section of the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application

- The statistically adjusted end-use (SAE) model description referenced in the load forecast section
- Evaluation of the Residential Inclining Block Rate, Fiscal 2013 to 2017

Elasticity Estimates

As part of its 2008 Long-run Acquisition Plan, BC Hydro retained Dr. Orans to provide expert testimony regarding appropriate price elasticity estimates and their use in assessing rate-induced conservation. Dr. Orans recommended that BC Hydro adopt a single price elasticity to simplify its process, arguing that the distinction between short- and long-run elasticities is unnecessary because the effect of the latter are accounted for in DSM program/codes and standards savings. Long-term price elasticity reflects the effect of capital stock adjustment induced variations in consumption caused by both rate changes and DSM programs/codes and standards. He argued that in low electric rate jurisdictions, such as British Columbia, it is reasonable to assume that such long-term capital stock adjustment induced energy conservation are mostly due to DSM and related policy changes.

Dr. Orans expressed concern about the potential for double counting energy savings by applying a long-term price elasticity estimate on top of the effects of energy efficiency programs and codes and standards. Dr. Orans recommended that BC Hydro adopt a price elasticity of -0.1 to estimate the aggregate impact of a rate increase and rate design change (flat rate to inclining block rate). Lastly, Dr. Orans indicated that it was reasonable for BC Hydro to use a price elasticity of -0.05 to estimate the rate level change induced conservation to split total conservation effects under an inclining block rate structure into rate level and rate design change components. BC Hydro adopted these recommendations and has been using a price elasticity of -0.05 to estimate the impact of rate changes on load forecasts ever since.

In April 2018, BC Hydro published an evaluation of its residential inclining block rate (RIB) for fiscal years 2013-2017 which was a follow-up to the 2013 RIB evaluation.[4] The RIB has two tiers (with a bi-monthly consumption threshold of 1,350 kWh) and was designed to encourage additional conservation. Price elasticity estimates featured prominently in this evaluation including their appropriate values, differences by customer characteristics, and their use to estimate the conservation impacts of the RIB rate. The 2018 evaluation found tier-one price elasticity to be -0.14 and tier two-elasticity to be -0.08. The lower elasticity estimate for tier-two was somewhat surprising as it goes against prevailing assumptions and findings elsewhere of increasing price elasticity for inclining block rate designs. In the 2013 RIB evaluation, BC Hydro was not able to estimate a statistically significant price elasticity for tier 1 customers, but found tier-two price elasticities to range from -0.08 to -0.13.[5]

In addition to evaluating the price elasticities of the RIB, BC Hydro attempted to evaluate the energy savings associated with the inclining block rate design separate from the impact of rate increases. The evaluation assumed that the range of elasticities found between tier-one and tier-two (-0.08 to -0.14) represented the "natural conservation" or the conservation that would have happened under a flat-rate structure. Additional conservation above the natural conservation represented energy savings associated with the rate design. The RIB evaluation concluded that the 2016-17 RIB energy savings were small or zero.

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[4] Evaluation of the Residential Inclining Block Rate, F2009-F2012 - Revision 2 (prepared by Power Smart Evaluation), 2014.Ibid.

[5] Ibid.

Load Forecasting

BC Hydro uses a combination of historical trends, regional economic inputs, end-use average stock efficiency estimates, and site-specific estimates for the largest customers to produce sector-level load forecasts. Residential use per customer forecasts are based on an SAE model which incorporates regional economic variables, temperature, and the average stock efficiency of various end-uses while residential account number forecasts are based on housing starts. These values are combined to forecast residential load. The commercial and industrial sector forecasts are further segmented (e.g. large industrial customers (transmission), commercial, distribution, industrial distribution, streetlighting, irrigation, etc.) and include sub sector-level industrial forecasts, and in some cases customer-specific forecasts (and risk assessments) for the largest accounts. The commercial distribution forecasts also rely on SAE models that are driven by regional GDP, employment, retail sales, weather, and average stock efficiency of modeled end-uses. After the sector-level load forecasts are produced, BC Hydro incorporates the effect of rate impact. Currently, BC Hydro applies a price elasticity estimate of -0.05 to all sectors for this purpose. Lastly, BC Hydro includes incremental DSM savings to develop the total forecast.

2.2 Jurisdictional & literature review - elasticity estimates and applications

This section summarizes our findings from DNV GL's jurisdictional and elasticity literature review. DNV GL focused its review on selected utilities' long-run load forecast reports and rate filings, as well academic studies and other elasticity focused literature.

2.2.1 Summary of elasticity estimates

Table 1 provides a summary of price elasticity estimates used in load forecasting and rate impact assessments that DNV GL reviewed. In the first column, we indicate the source of the estimates (including of the data), which is either a utility that filed a jurisdictional case or a non-utility study. The details of the elasticity estimates, including their values, what sectors they apply to, and whether they are short- or long-run, are included in the" elasticity details" column. The third column presents the source of the elasticity estimates (internal or external study), the method, and time-period used to derive them (if available). The fourth column indicates the application in which the elasticities were used (e.g. in a load forecast or rate impact assessment used in regulatory filings or a non-utility elasticity estimate study). The final column provides the name and date of the source document.

Table 1: Summary of elasticity estimates[6]

Utility/Entity/Study	Elasticity Details	Elasticity Source & Methodology	Elasticity Application	Document/Date
Fortis BC (Fortis BC data)	Short-run residential = -0.09 Long-run residential = -0.16 to -0.20	Internal - Regression models of average use as a function of marginal price and	Rate impact estimate (RIB rates)	Residential Conservation Rate Information Report for the Period July 1, 2012

[6] We also searched for elasticity details from Hydro Quebec, Idaho Power, and Puget Sound Energy(PSE) but did find not useful information from their regulatory filings. We were, however, able to find a summary of the load forecasting methodology and price elasticity estimates used by PSE in its 2005 IRP filing in the Carvallo et al. (2016) study.

Utility/Entity/Study	Elasticity Details	Elasticity Source & Methodology	Elasticity Application	Document/Date
		weather by rate tier using 2012-2014 data		to June 30, 2014, 11/28/2014
Fortis BC (Fortis BC data)	Residential rate tier 1= -0.07 Residential rate tier 2 = -0.14	Internal - Regression models of average use as a function of marginal price and weather by rate tier using 2012-2014 data	Rate impact estimate (TOU rates)	2017 Cost of Service Analysis and Rate Design Application, 12/22/2017
Manitoba Public Utility Commission[7] (expert judgment informed by literature review)	Recommended short-run (1 year, all sectors) = -0.1 Recommended long-run (all sectors) = -0.4 Recommended long-run residential = -0.35 Recommended long-run commercial & industrial = -0.5	External - Expert testimony of Adonis Yatchew based on extensive literature review including results of meta-analysis (detailed below)	Rate impact estimate	Before the Public Utilities Board of Manitoba Manitoba Hydro General Rate Application 2017/18 and 2018/19 - Expert Testimony Of Adonis Yatchew, 11/15/17
Newfoundland Power (data source not given)	Domestic/residential and general service (demand 0-100 kW) = -0.20	External – Methodology and source not provided	Rate impact estimate	Newfoundland Power - 2016/2017 General Rate Application Volume - Customer, Energy and Demand Forecast, 10/2015
New Brunswick Power (data source not given)	Short-run residential = -0.21	External – Methodology and source not provided	Load forecast (SAE models)	Information Package relating to New Brunswick Power Distribution and Customer Service Corporation forecasted revenues and costs for 2009/2010, 5/30/2009
Nova Scotia Power (data source not given)	Short-run residential, small general and general service = -0.15	External - Provided by Itron	Load forecast (SAE models)	Nova Scotia Power - An Emera Company 2016 Load Forecast Report, 5/2/2016
SaskPower (data source not given)	Cites the recommended short and long-run elasticity estimates from Manitoba rate application for estimating customer impact (above)	Same as Manitoba	Rate impact estimate	Saskatchewan Rate Review Panel – Regarding the SaskPower 2017 Rate Application, 3/1/18
Yukon Energy (data source not given)	Short-run residential and commercial = -0.10	External - Itron 2006 Price Effects survey	Load forecast (SAE models)	Long Term Load and Demand Forecast Yukon Energy Corporation (YEC), 3/8/2016
CA state-wide (California utilities' data)	Average across all sectors = -0.10 (sector specifics estimates unavailable)	Internal - Methodology not provided	Load Forecast	California Energy Demand 2018-30 Revised Forecast, 4/19/18

[7] Manitoba Hydro proposed to use elasticities of -0.28 for residential, -0.13 for commercial (general service small/medium), and -0.46 for large (general service large) customers in 2017.

Utility/Entity/Study	Elasticity Details	Elasticity Source & Methodology	Elasticity Application	Document/Date
Pacific Gas & Electric Company - PG&E (synthesis of estimates from the literature)	Average price approach Short-run residential = -0.18 Tier-specific approach Short-run Residential tier 1 rate = -0.13 Short-run residential tier 2 rate = -0.26 Marginal price approach Short-run residential lower tier = -0.13 Short-run residential outer tier = -0.18	Both internal and external - PG&E and SCE elasticity estimates used to determine the residential rate design impact on electricity consumption are based on three different methodologies (details on methods provided below)	Rate impact estimate Rate impact estimate	Joint Utility Rebuttal Testimony of Dr. Ahmad Faruqui on Demand Elasticity and Conservation Impacts of Investor-Owned Utility Proposals, 10/17/14
Southern California Edison – SCE (SCE data)	Average price approach Short-run residential = -0.17 Tier-specific approach Short-run residential tier 1 rate = -0.13 Short-run residential tier 2 rate = -0.26 Marginal price approach Short-run residential lower tier = -0.13 Short-run residential outer tier = -0.19			
San Diego Gas & Electric - SDG&E (SDG&E data)	Short-run residential = -0.10	Internal - An econometric model used to forecast residential sales.		
PacifiCorp (pacific power (CA, OR, WA) utilities' data)	Price elasticity Long-run residential = -0.10 to -0.40 Peak to off-peak substitution elasticity Residential = 0.08 to 0.090 Non-residential = 0.03 (health care) to 0.17 (manufacturing) Agricultural = 0.09 to 0.32	External - From studies by NREL (2006), Brattle Group (2008) and Freeman, Sullivan & Co (2012) price elasticity estimates based on 1977-2004 data	DSM resource forecast	Assessment of Long-run, System-Wide Potential for Demand-Side and Other Supplemental Resources, 2013-032 Volume I, 3/2013
Portland General Electric – PGE (PGE data)	Short-run residential = -0.10 Long-run non-residential = -0.03	Internal - PGE elasticity estimates have remained stable since 2002. Derived from a "price model" that was re-estimated in 2013 using 1985-2013 data.	Load forecast	Before the Public Utility Commission of the State of Oregon, Portland General Electric Load Forecast – Direct Testimony of Ham Nguyen and Sarah Dammen, 2/13/14
Public Service Company of Colorado – PSCo (data source not given)	Residential, commercial and industrial = -0.15	External - Provided by Itron	Load forecast (SAE models)	Public Service Company of Colorado 2016 Electric Resource Plan Volume 2,

Utility/Entity/Study	Elasticity Details	Elasticity Source & Methodology	Elasticity Application	Document/Date
				5/27/2016
Public Service Company of New Mexico – PNM (PNM data)	Short-run residential PNM South (10% of residential use) = -0.06 PNM North (90% of residential use) = -0.19 Short-run commercial PNM South (<10% of commercial use) = -0.1 PNM North (>90% of commercial use) = -0.2 Short-run irrigation = -1.2	Internal - Log-log models with average daily use (per customer for residential and total for commercial and irrigation) as a function of price, weather, monthly dummies, and autoregressive terms, and regional labor force levels for commercial using 1999-2008 data	Load forecast	In the Matter of the Application of Public Service Company of New Mexico For a Revision of Its Retail Electric Rates Pursuant to Advice Notice Nos. 397 And 32 (Former TNMP Services) Case No. 10-00086-UT - Direct Testimony and Exhibits of Jonathan A. Lesser, PhD on Behalf of Public Service Company of New Mexico, 6/1/2010
Seattle City Light – SCL (SCL data)	Residential = -0.08 Commercial = -0.14 Industrial = -0.21	Internal - Methodology not provided	Load forecast	2013 System Load Forecast, 12/6/2016
Labandeira (2017) (synthesis of estimates from the literature)	Short-run = -0.13 Long-run = -0.37	Analysis of elasticity estimates from over 400 papers and 900 individual short and long-run elasticity estimates.	Elasticity estimate study	A meta-analysis on the price elasticity of energy demand, 2017
EPRI (2008) (synthesis of estimates from the literature)	Short-run price elasticity Residential = -0.3 (range -0.2 to -0.6) Commercial = -0.3 (range -0.2 to -0.7) Industrial = -0.2 (range -0.1 to -0.3) Long-run price elasticity Residential = -0.9 (range -0.7 to -1.4) Commercial = -1.1 (range -0.8 to -1.3) Industrial = -1.2 (range -1.2 to -1.4) TOU Substitution elasticity Residential = 0.04-0.21 Non-residential = 0.04-0.11	Synthesis of several studies that provide price elasticity estimates from dynamic pricing pilots under a variety of conditions	Elasticity estimate study	Price Elasticity of Demand for Electricity: A Primer and Synthesis, 2008
Carvallo et al. (2016) (listed utilities' data)	NV Power Residential = -0.10 Puget Sound Residential = -0.19 Commercial = -0.16 Industrial = -0.19 Avista Residential = -0.15 Commercial = -0.10 Cross price elasticity (all classes) = 0.10	Evaluation of load forecasting methods and outcomes featured in IRPs from 12 Western U.S. utilities – no indication whether price elasticities are short- or long-run	Elasticity estimate study (load forecast evaluation)	Forecasting in Electric Utility Integrated Resource Planning, 2016

Utility/Entity/Study	Elasticity Details	Elasticity Source & Methodology	Elasticity Application	Document/Date
	PacifiCorp All classes = -0.10			
Ros (2017) (U.S. distribution utilities' data)	Long-run Residential = -0.38 to -0.61 Commercial =-0.42 to -0.75 Industrial = -0.52 to -0.87	An econometric study of residential, commercial, and industrial electricity demand using data from 72 U.S. distribution companies for the years 1972-2009	Elasticity estimate study	An Econometric Assessment of Electricity Demand in the United States Using Utility-specific Panel Data and the Impact of Retail Competition on Prices, 2017

The research results indicate that there is a wide range of price elasticity estimates used in various applications. Some utilities use sector specific elasticity while others apply a singular estimate to all sectors (like BC Hydro). Similarly, there is no consistency between the use of short and long-run elasticity estimates by the utilities reviewed by DNV GL. We provide a more detailed discussion of short- and long-run price elasticity estimate definitions and uses in section 2.2.5 and the conclusions and recommendations in section 2.3. Here we note that our survey indicated short-run elasticities range from -0.06 to -0.26 for the residential sector[8], from -0.03 to -0.70 for the commercial, and -0.03 to -1.20 for the industrial sector. The long-run counterpart values range from -0.10 to -1.40 for the residential sector, from -0.50 to -1.30 for the commercial, and -0.50 to -1.40 for the industrial sector.

In our survey, the most commonly reported price elasticity for the residential sector is -0.10. While values as low as -0.06 and as high as -0.26 are in use among the utilities we reviewed, the most commonly reported value is a useful indicator of typical consumer response to rate changes. The -0.10 value is also most commonly reported for the two other sectors. Further, this value (-0.10) was recently recommended in an expert testimony to the Manitoba Public Utilities Commission presented in the table above. The expert in that testimony, Dr. Yatchew, cited numerous studies including a recent meta-analysis of price elasticity estimates which collected over 900 short and long-term elasticity estimates from over 400 papers published between 1990 and 2016. The meta-analysis found an average short-term elasticity of demand for electricity of -0.13 and an average long-term elasticity of -0.37.[9] Informed by findings from this and other studies, including a 2017 U.S. state level study[10], Dr. Yatchew recommended that Manitoba Hydro adopt a short-run price elasticity of -0.1 across all sectors.[11]

2.2.2 Price elasticity applications

In addition to looking at the specific elasticity estimates used by utilities included in the jurisdictional review and cited by academic studies, DNV GL also researched how the elasticity estimates were applied. We focused

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[8] The range excludes an outlier value of 0.6 reported in the 2008 EPRI synthesis for the residential sector,

[9] Labandeira, 2017.

[10] Burke and Abayasekara (2017).

[11] He also recommended a long-run price elasticity of -0.4 when considering the proposed rate increase of 65% over time. This long-run price elasticity estimate is applicable when considering the long-term impact of rate increase inclusive of DSM that results in capital stock adjustments.

our jurisdictional research on utility load forecasting for long term resource planning and short term rate impact cases.

Load Forecasting

In IRPs and other long-term load forecasting exercises, price elasticity estimates are used to account for rate changes over the forecast period. Load forecast approaches vary by utility/jurisdiction and the models and inputs each utility uses are unique to their jurisdiction, but overall, the approach to load forecasting and application of elasticity is very similar amongst the utilities we reviewed. Utilities typically use one of two basic modeling approaches: statistically adjusted end-use (SAE) modeling or econometric modeling. SAE models forecast load (as a function of heating, cooling and base use) based on the saturation and efficiency of end-use appliances and the amount of energy they use. Econometric models forecast load based on the relationship between energy demand, weather, and economic variables (e.g. GDP, income, etc.) and price. In both cases, forecasts of energy use are made for residential, commercial and industrial rate classes separately. Like BC Hydro's approach, industrial load forecast is often not model based, but is developed based on customer specific information and other drivers such as commodity prices and global outlooks. In general, regardless of the modeling approach, price elasticity estimates are applied to rate escalation assumptions over the course of forecast to determine the rate impact on the forecast.

Rate Impacts

There is no real difference in the application of price elasticity in "load forecasting" and "rate impacts." In both cases, utilities use price elasticity to estimate the impact of rate changes on electricity demand. However, there appears to be increased regulatory scrutiny on the estimates and application of price elasticity in rate impact cases which tend to focus on the short-term (1-3 years) impact of the rate change. We observed examples of external stakeholders voicing concerns about the methodology used to assess the rate change (i.e. the application of elasticity) and the elasticity estimate used in rate filings. The methodology used to estimate the rate impact varied depending on the details of the rate case and was inconsistent across jurisdictions. In some cases, utilities developed models to estimate the price elasticity of their customers while other jurisdictions relied on academic studies or precedent set by other utilities.

The review of how price elasticity estimates can be used to determine rate impacts provided in a multi-utility rate case in California is particularly informative. Conducted by Dr. Faruqui, the case presents how the consumption effect of moving from a four- to two-tier pricing regime can be determined. Three methodologies, that are in use in the industry, are:

- The **tier-specific methodology**, where the price change in each tier is assumed to affect consumption in that tier, is from triangular probability distributions the Brattle Group computed for short-run and long run elasticities based on data from price elasticity studies.[12] Dr. Faruqui determined average short-run price elasticities to be -0.13 for tier 1 and -0.26 for tier 2 rates and long-run price elasticities to be -0.39 and -0.78 for tier 1 and 2 rates using this methodology.

[12] Faruqui, 2008.

- The **average price methodology**, where customers are assumed to respond to average price changes, is a consumption weighted average of the tier specific elasticities of -0.18 for PG&E and a price elasticity of -0.17 for SCE obtained from an internal study the utility conducted based on 15-year residential customers billing data.
- The **marginal price methodology**, where only the highest tier (marginal) price applicable to the last (highest) unit of consumption is assumed to affect change in consumption, is based on consumption weighted average of the tier specific prices for the outer tier (-0.18 for PG&E and -0.19 for SCE) and tier 1 value for the lower tier (of -0.13 for both).[13]

Dr. Faruqui did not identify a big range of results from the three methods. Two of the methods (the average price and tier-specific methodology) indicated a maximum consumption decrease of 2% while the third (the marginal price) indicated a maximum consumption increase of 1.7%. The base case scenarios from each methodology resulted in consumption changes much less than these for each utility studied. Overall, the results were used to justify why moving to a flat rate does not harm conservation. The results from these methods showed the full range of possible outcomes and the uncertainty inherent in customer response to rate/rate design changes.

2.2.3 DSM

How does one identify pre-DSM price elasticities?

We found an example of a load forecasting methodology that permits the identification of pre-DSM price elasticity. PNM's residential use per customer load forecasting model featured in Table 1 includes an energy efficiency proxy so that the estimated coefficient of price is an estimate of price elasticity of demand holding the effect of all factors, including energy efficiency program savings, constant.[14] The price elasticity estimate, in a sense then, is a pre-DSM value.

Other than PNM's study, no other utility provides how pre-DSM price elasticities can be identified. However, we found that it's common practice to adjust forecast model results for the incremental impact of DSM programs. For example, Nova Scotia Power accounts for past DSM savings in its load forecast by subtracting portions of DSM savings already accounted for in current load; it determines the level of DSM savings already in current load by including historical cumulative DSM values in the average use SAE regression models. Similarly, Portland General Electric adjusts its forecast to account for the impact of incremental energy efficiency programs; it reduces the forecast by the amount of incremental energy efficiency levels in the forecast year. California's IOUs, PSCo and PacifiCorp also follow a similar practice.

How does DSM affect price elasticity estimates over time?

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[13] For customers whose consumption falls in tier-two, an income ("expenditure") effect for the tier-one energy they consume is also considered when estimating the impact of the rate design using the marginal price approach.

[14] The study used 1990/year(t) as a proxy for overall energy efficiency; 1990 was the start of the study period and the value of the proxy decreased over the study period that ended in 2008. The decreasing trend reflects improvements in energy efficiency of the capital stock increase but at a decreasing rate. The proxy reflects that idea that while the efficiency of energy using appliances and equipment improve every year, they will always use some amount of energy no matter how efficient they become. The coefficient estimate of this variable measured the average reduction in kWh/customer per day each month. Since PNM began DSM programs in 2007, the study did not use the energy efficiency coefficient estimate, which is inherently uncertain, to project DSM savings. But, it indicated how it is possible to account for DSM savings using a residential use per customer regression model.

The authors of the 2008 EPRI paper cite a study that indicates that the presence of DSM lowers price elasticity estimates over time.[15] Per the cited study, the level of price elasticity among California's customers was lower at the time of the study than 25 years earlier due to the state's aggressive promotion of energy efficiency measures and programs. The authors indicate that DSM programs have lowered customers' ability and willingness to respond to price changes. They do not provide the price elasticity estimates used in the earlier study they refer to nor the one they used in their study. Further, no other utility studies we found indicated how the presence of DSM affects elasticity estimates over time and, thus, we can only draw tentative conclusions that the presence of DSM may lower price elasticity estimates over time.

2.2.4 Rate Structures and customer sectors/segments

Should elasticities be different depending on the rate structure to which they are assumed to apply (flat rate, time of use rate, tiered)?

We identified only one study that uses different elasticities for different rate structures. That is PNM, which uses different price elasticity estimates for those on flat and tiered rates to generate load forecasts. It applies lower elasticity estimates to PNM South customers (of -0.06 to residential and -0.10 to commercial customers) that face a flat rate and higher price elasticity estimates to PNM North customers (of -0.19 for residential and -0.20 for commercial customers) that face increasing block rates. The values applied are based on elasticity estimates PNM developed for the two geographic areas, which happen to face different rate structures, separately and by sector.

We recommend that BC Hydro also applies price elasticity estimates that are relevant to its customers, who face tiered rates. Since it has estimates of the price sensitivity of its (residential) customers that face this type of rate, it can apply these values in its business applications. Where a single price elasticity estimate is needed, the estimates obtained from its empirical studies should inform that value. We discuss the value we recommend for this purpose and the rationale in section 2.3.

Does it make sense to apply elasticities to industrial sectors with few, large participants and where an assessment of future customer viability is already made based upon expert advice?

Yes, it does, unless a comprehensive and detailed assessment of price effects is already completed using an alternative method such as a survey that queries each customer about their response to rate increases. Large industrial customers are generally more price sensitive than residential and commercial customers. Several elasticity studies that we reviewed (including the Manitoba Hydro testimony of Dr. Yatchew and Ross (2017)) indicate price elasticity to be higher for the industrial sector than for the other sectors. In addition, we found several load forecasting studies (the California state-wide energy forecast, and forecasts for Public Service Colorado, Seattle City Light, Portland General Electric, and Puget Sound Energy) that apply price elasticity estimates to assess rate impact on their industrial load forecasts. The elasticity estimates applied to gauge the impact of rate changes on industrial load forecasts are either the same or higher than those used for the residential and commercial sectors except in one (Portland General Electric) case.

[15] Faruqui and George, 2005.

The remaining question then is the applicability of the practice the utilities we identified as using price elasticity estimates to alter industrial load forecast to BC Hydro's context. Three of the utilities above (Puget Sound Energy, Manitoba Hydro and Seattle City Light) are winter peaking and have substantial hydro generation. Public Service Colorado and Manitoba have industrial customers engaged in mining and extraction industries that are generally like those BC Hydro serves. All the utilities that adjust industrial load for price effect also have various types of large industrial customers.

Therefore, given that industrial load customers are generally more price sensitive than other sector customers; that it is common practice to apply price elasticities even for forecasts made based on site-specific information; that utilities like BC Hydro either in the large customer mix they serve or in being winter peaking follow this practice, we find that it is reasonable to adjust industrial load for rate impact using price elasticity estimates. This is the case even when BC Hydro’s large industrial customer-specific forecast already has some price response effects already built into it.

If BC Hydro were to survey all industrial customers about how they would respond to future rate changes, and BC Hydro were able to incorporate the results of that survey into load forecast, then it may not also be appropriate to apply a price elasticity. In order for the survey approach to be a valid alternative to the use of price elasticity, the survey would need to be comprehensive and would need to ask about response to rate changes alone in the absence of other drivers of changes to consumption.

What kind of behavioral and non-behavioral changes should be included in short-run and long-run elasticities of substitution (TOU rate)?

Time-varying rates (TOU, CPP and RTP) can induce both shifts in consumption from peak to off-peak periods and possible changes in overall consumption. In the former case, shifts in energy demand from periods where its price is higher (peak period) to periods where it is lower (off-peak) can be measured using substitution elasticities. Short-run substitution elasticities reflect behavioral changes such as pre-cooling homes before peak periods, and shifting laundry and dishwashing activities from peak to off-peak periods. In the long-run, both residential and non-residential consumers can adjust the stock of energy-using equipment in response to peak period price increases.

The relevant distinction between short- and long-run, is whether responses reflect behavioral changes only or both behavioral and capital stock/electricity using equipment changes (non-behavioral changes). As long there is data of sufficient length (which is at least two years or more post rate changes based on industry practice that we reviewed), it is possible to estimate the net effect on consumption of rate/rate design changes inclusive of both behavior and capital stock changes. Examples of behavioral changes and non-behavioral changes are useful, but an exhaustive list of these is not necessary.

What is the range of uncertainties on short-run and long-run elasticity of substitution (TOU rate) estimates?

Two sources from the literature helped us identify values and ranges for elasticities of substitution for TOU rates. These studies indicate that residential substitution elasticities can range from 0.04 to 0.21 while non-residential values can take on values from 0.03 to 0.17 (and 0.32 for agricultural customers). PacifiCorp used substitution elasticities that ranged from 0.08 to 0.09 for residential customers, 0.03 to 0.17 for non-residential customers, and 0.09 to 0.32 for agricultural customers to determine the demand impact of its proposed TOU rates. It used various studies to determine these values.[16] In addition, the EPRI (2008) study provides a synthesis estimate of substitution elasticities that range from 0.04 to 0.21 for residential customers and from 0.04 to 0.11 for commercial customers on TOU rates. These are short-run elasticities and there no indications of what long-run substitution elasticities values are likely to be.

Under a TOU rate, how should consumption change during peak and off-peak hours be attributed to substitution (change consumption from peak to off-peak period) and change in demand (reduction in use during peak)?

It is possible that time-varying rates not only affect patterns of consumption (shifts from peak to off-peak period), but also the level of consumption and peak demand. To estimate such changes, it is necessary to determine the price elasticity of demand for peak and off-period prices and apply those to energy use. Fortis BC applied a lower price elasticity (of -0.07) to off-peak and a higher price elasticity (of -0.14) to on-peak rates to assess the energy use effect of its propose TOU rate. These elasticity estimates were obtained from its RIB rates and it is not clear why they were deemed applicable to peak and off-peak rates.

While we have not conducted an exhaustive study on the topic, and leave this as one potential gap in our research, estimated substitution elasticities can be applied to determine peak to off-peak demand reductions. Energy use and peak demand reductions can be made using estimated price elasticity of demand. Past studies have indicated not only load shifting (peak to off-peak period), but also energy use reductions due to time-varying rates. The 2008 EPRI study indicates several pilots that run time-varying rates found a reduction in both peak-period and overall energy use.

What is a reasonable substitution price elasticity, for customers and end uses for which natural gas is substitute for electricity?

Estimates of cross-price elasticity for customers and end uses for which natural gas is a substitute for electricity is only reported in two cases. Carvallo et al. (2016) indicate Avista used a cross price elasticity of 0.10 for natural gas for all classes to forecast load in its 2005 IRP filing. Ros (2017) finds the cross-price elasticity of demand for natural gas to be 0.09 and 0.10 for residential and commercial customers, and 1.24 for industrial customers. The former two values are in line for those reported and used by Avista in its 2005 IRP.

2.2.5 Short vs. Long Run Price Elasticity

How much difference is there between short-run and long-run elasticities and, given the rapidly changing world, how long should long-run elasticities be?

In theory, the distinction between short-run and long-run price elasticities of electricity demand is clear. Short-run price elasticities are lower and reflect behavioral responses (such as turning off lights and lowering thermostat settings). Long-run price elasticities, on the other hand, are larger and reflect changes (including capital/durable goods adjustments, more efficient energy use processes and possible substitution to other fuels) that take sufficient time to materialize.

[16] Bernstein and Griffin, 2006, Edison Electric Institute, 2008, and Freeman, Sullivan & Co., 2012.

Short-run effects are estimated using limited time-series data, such as two years where enough time has not passed to permit adjustments in electricity using capital/equipment. Long-run effects can be estimated whenever there is data that incorporates adjustments in appliances and other electricity using equipment and processes. Cross-sectional data from different utilities or data from a single utility with multiple years of observations, and with sufficient variation in rates, enable the identification of long-run price effects. However, even in this setting if there are policies related to energy efficiency, technological or economic changes that also alter the capital stock in use by consumers, then models can only reflect the net effect of price changes over time.

Capital stock adjustment induced changes in consumption may be affected by rate changes, DSM/energy efficiency policies, technological developments and other factors. In jurisdictions with low electricity rates, it is reasonable to assume that capital stock changes are largely in response to factors other than electricity rates. However, measured price elasticities using data that already reflects lower energy use due to DSM and other factors that affect stock turnover can be taken to reflect net price effects. Thus, the real distinction is not whether short- or long-run price effects are estimated and applied, but whether the elasticity estimate controls for factors that influence capital stock turnover. Estimates based on data where DSM savings and other factors that affect stock turnover have been accounted for elsewhere, including in the lower historical trajectory of the energy use data, reflect price effects net of stock turnover effects.

To the extent that a demand forecast already accounts for the effect of capital stock turnover, it may be inappropriate to also apply a long run price elasticity that also attempts to capture this same effect. BC Hydro's Load Forecast accounts for the future impacts of a DSM plan that includes energy efficiency codes and standards and other measures that impact capital stock turnover. It also accounts for stock turnover though the SAE model for residential and commercial sectors Given this, our recommendation for BC Hydro is to eschew short- versus long- run price elasticity distinctions and instead to apply price elasticities estimated using energy data that already accounts for factors that impact stock turnover, such as past DSM initiatives. Further, price elasticity effects can change over time in response to rate and rate structure changes; potential changes in DSM policies and initiatives; and other changes in local conditions that affect demand. Determining the price elasticity is an empirical question that can only be answered with recurring (possibly every three to four years of) demand modelling of energy use.

What kind of behavioral and non-behavioral changes should be included in short-run and long-run elasticities of demand?

The residential conservation rate (RCR) impact study provided by Fortis BC indicates that short-run price elasticities should include behavioral responses such as turning off lights and lowering thermostat settings. In his testimony for PG&E's and SCE's residential rate design reform, Dr. Faruqui also considers behavioral changes (such as turning off lights and lowering thermostat settings) to drive short-responses. Long-run price elasticities, on the other hand, include appliance and structural changes including energy-efficient building shells. Yatchew's Manitoba Hydro testimony similarly indicates long-run price elasticities include the use of more efficient capital stock and migration to alternative fuels.

Given the distinction we made earlier of net and total price effects, estimated price elasticities do not reflect the effect of DSM. Therefore, DSM savings should be estimated separately and should be used to adjust load forecasts. In other words, the current practice that BC Hydro follows of adjusting load forecast for rate impacts and then for DSM activities is a sound one.

Our conclusion on this topic is that short-run price elasticities reflect all types of behavioral responses while long-run price elasticities reflect, additionally, changes in capital stock (including those induced by DSM activities). Thus, the distinction is not between short- and long-run price elasticities, but between price elasticity estimates that attempt to capture capital stock turnover and fuel switching as a price effect, and those that do not.

What is the range of uncertainties on short-run and long-run elasticity of demand estimates?

As indicated in section 2.2.1, short-run elasticities range from -0.06 to -0.26 for the residential sector, from -0.03 to -0.70 for the commercial, and -0.03 to -1.20 for the industrial sector. The long-run counterpart values range from -0.10 to -1.40 for the residential sector, from -0.50 to -1.30 for the commercial, and -0.50 to -1.40 for the industrial sector.

Given the literature we reviewed indicates -0.1 to be the most common elasticity; that BC Hydro's data indicates values (-0.08 to -0.14) that surround this value; that BC Hydro's consumption weighted tier-one and tier-two price elasticity is roughly -0.09; and that the previous assessment of elasticity by BC Hydro Expert Dr. Orans found -0.10 to be suitable for BC Hydro, we find a value of -0.10 for BC Hydro to be a reasonable value.

What are the differences in short-run and long-run elasticities of demand for residential customers by consumption level, region, heating fuel and dwelling type?

Our research yielded limited information on these topics and, thus, we can't draw conclusions on the matter. What we did find is estimates of short-run price elasticities for residential customers that vary by income and region in the 2011 rate application testimony filed by PNM. PNM's testimony indicates that low income customers' demand is more price elastic than higher income customers' demand. The short-run price elasticity of demand for low income customers, with less than $20,000 annual income, is estimated to range from -1.6 to -2.0 while that of customers with more than $20,000 annual income was estimated to range from -0.20 to -0.36. When the low-income threshold is $30,000, low-income elasticity is -1.3 and higher-income elasticity ranges from -0.10 to -0.14. We also found one study that indicated higher price elasticity for customers that use electric heat (Fortis BC 2014 RIB evaluation).

Based on the dearth of information we uncovered on the remaining issues (difference in elasticity by consumption level and dwelling type), apart from those in BC Hydro's RIB evaluation, we recommend a future study investigate this issue in more depth to fill this gap.

2.3 Elasticity analysis, conclusions and recommendations

This section contains DNV GL's analysis, conclusions drawn from our research and recommendations on price elasticity estimates and their application. DNV GL also provides a recommendation for how to approach the impact analysis when investigating a move from an inclining block rate to a flat rate structure. While not necessarily part of the original scope of work, DNV GL's price elasticity literature review uncovered a relevant example from California on the topic.

Elasticity estimate

The current investigation was prompted by the need to examine the price elasticity estimate of -0.05 that is used by BC Hydro to forecast load and assess the impacts of general rate increases. The price elasticities in use by utilities and reviewed in this study are wide-ranging. The variation in elasticity estimates across studies reflects the fact that consumer response to electricity price changes are not uniform, instead reflecting local conditions (such as weather, economic activity and energy efficiency policies) under which consumption takes place. From a practical point of view, however, they offer a range of price elasticities, and points of comparison for the business applications of interest to BC Hydro.

Based on our review, short-run elasticities range from -0.06 to -0.26 for the residential sector[17], from -0.03 to -0.70 for the commercial, and -0.03 to -1.20 for the industrial sector. The long-run counterpart values are two- to three-times larger than the short-run values. In our survey, the most commonly reported price elasticity for the residential sector is -0.10.

BC Hydro's current price elasticity estimate is derived from expert testimony provided by Dr. Orans as part of the 2008 Long Term Acquisition Plan. Dr. Orans recommended that BC Hydro "should adopt a conservative price elasticity of -0.1 to estimate the aggregate impact of an average rate increase and a rate design change from a flat rate to an inclining block tariff for residential and commercial customers." Dr. Orans suggested that it would be reasonable for BC Hydro to split the -0.1 elasticity estimate between rate level-induced and rate design-induced conservation, which resulted in BC Hydro's current price elasticity of -0.05 for all sectors. We did not see evidence of other utilities splitting elasticity between rate design and rate level effects (except Fortis BC, which follows an approach similar to BC Hydro). Further, BC Hydro's most recent RIB evaluation pointed to limited, and in some cases no savings, associated with the inclining block rate design. That being said, we note that Dr. Orans original price elasticity estimate of -0.1 is consistent with the wider literature on price elasticity.

Lastly, BC Hydro's work in this area provides useful data points that can inform reasonable price elasticity estimates for its residential sector. BC Hydro's two studies on the impact of the RIB rate on consumption indicate that price elasticities for its residential customers range from -0.08 to -0.14. BC Hydro's 2013 RIB evaluation identified price elasticities of -0.08, -0.1 and -0.13 for step 2 (tier-two) customers. Its 2016/17 RIB evaluation indicated price elasticities of -0.14 for step 1 (tier-one) and -0.08 for step 2 (tier-two) customers. Based on fiscal years' 2016 and 2017 average aggregate marginal consumption of 3,859 GWh/year for tier 1 and 11,943 GWh/year for tier 2, we note that about 24% of marginal consumption is in rate tier 1 and 76% in rate tier 2. Using these estimates, we derive a weighted average price elasticity for the residential sector of -0.09.[18]

Although not statistically significant, BC Hydro also finds a price elasticity of -0.10 for residential customers in New Westminster located in Lower Mainland BC served by another municipal electric utility; these customers are on a flat rate and considered comparable to BC Hydro's customers.

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17 The range excludes an outlier value of -0.6 reported in the 2008 EPRI synthesis for the residential sector.

18 Several studies, including Ito (2014) and Borenstein (2009) indicate customers respond to average bill changes or perceived average rates. Thus, a consumption weighted average price elasticity is another good data on the price elasticity that is applicable for BC Hydro's residential sector.

Values from external sources, as well as those determined by BC Hydro from its own and neighbouring utility data, indicate a residential price elasticity value that centres around -0.10 is a reasonable value for BC Hydro's residential customers. Therefore, we recommend that BC Hydro increase the price elasticity in use to assess rate impact and determine load forecast growth for the residential customers. Based on the convergence of values, we find an increase to -0.10 to be reasonable.

Recommendation: DNV GL recommends that BC Hydro increase its current price elasticity estimate of -0.05 to -0.10. The -0.05 estimate is at the low end of the range of the all the price elasticity estimates reviewed by DNV GL. It is also lower than recent price elasticity findings of -0.08 to -.14 from BC Hydro's RIB evaluations. We believe there are two different but equally reasonable approaches for BC Hydro to take to increase its elasticity estimate. In an ideal world, BC Hydro would use its own empirical data to estimate price elasticity. This would yield the most accurate estimate for BC Hydro. However, it would also be reasonable for BC Hydro to adopt the price elasticity estimate produced by this research.

BC Hydro estimate. BC Hydro can produce price elasticity estimates using its own data. This is largely already complete for the residential sector and based on our rough estimate, would result in an average price elasticity of around -0.09 for the residential sector. This approach would likely require additional elasticity studies of the commercial and industrial sectors to at the very least test whether those sectors are different enough from the residential sector to warrant sector specific estimates. In the meantime, absent better information, the residential sector elasticity estimate would have to be applied to all sectors.

Academic research/expert. Elasticity studies are challenging, time consuming, and may not be worth the investment given the efforts involved. Many utilities take this route and rely on academic studies or expert recommendations for their elasticity estimates. If BC Hydro decides to bypass additional elasticity studies and adopt a "reasonable value" from academic research and expert recommendations, then DNV GL recommends adopting an elasticity estimate of -0.1 for all sectors. This is consistent with the original recommendation made by Dr. Orans and the expert recommendation made in a recent Manitoba Hydro rate case by Dr. Yatchew. It is also the most commonly used price elasticity estimate by the utilities we reviewed and is consistent with the weighted average elasticity from BC Hydro's most recent RIB evaluation.

Sector-level elasticity

The literature indicates that, when price elasticity estimates are available for industrial sector customers, these customers are more price sensitive than are other customers such as residential. While some utilities have sector specific elasticity estimates that indicate higher elasticities for industrial customers, there is also evidence that many jurisdictions use the same elasticity estimate across all sectors, including PSE, PacifiCorp, and California (for multiple utilities).[19] for long-term load forecasting. BC Hydro's past studies on price elasticity for industrial customers are dated and in need of updating.

[19] California Energy Demand 2018-2030 Revised Forecast, California Energy Commission, Commission Staff Report, Document No. 17-IEPR-03, 4/19/2018.

Recommendation: In general, we find BC Hydro's application of price elasticity to be consistent with that of many of the Canadian and U.S. utilities we reviewed. DNV GL supports the continuation of BC Hydro's approach to load forecasting which involves building up sector specific forecasts, including site-specific large commercial and industrial forecasts, and applying a single price elasticity to account for price changes in the forecast. Given that BC Hydro employs a site by site assessment for industrial facilities which captures price effect for a selection of energy intensive facilities, such as pulp mills; and precedent elsewhere, of applying the same price elasticity across all three sectors, we recommend that BC Hydro continue to use the same price elasticity estimate for all sectors. The actual elasticity value will depend on whether BC Hydro adopts the weighted average elasticity from its 2016/17 RIB evaluation (-0.09) or the recommended -0.10 price elasticity estimate from our research and expert recommendations.

Short vs. long run elasticity

In theory, the distinction between short-run and long-run price elasticities of electricity demand is clear. Short-run price elasticities are lower and reflect behavioral responses (such as turning off lights and lowering thermostat settings). Long-run price elasticities, on the other hand, are larger and reflect changes (including capital/durable goods adjustments, more efficient energy use processes and possible substitution to other fuels) that take sufficient time to materialize.

In practice, how price elasticities (demand response to price changes) are measured and classified varies widely. As Yatchew, in a 2017 expert testimony, indicates price elasticity of energy demand can be estimated using various models and data types. Cross-sectional data are effective in identifying long-term price elasticities because such data reflect highly diverse electricity rates and demand from many utilities. Time-series data from a single utility can accomplish the same if the time span used is long enough and rate changes are sufficiently large. Panel data that combine the two often serve as the best approach for this purpose, which is why studies such as those by Jos (2017) use them to study long-run demand response to price changes. Jos used data from 72 distribution utilities covering more than 30 years (1972-2009) to estimate long-run price elasticities of -0.38, -0.42 and -0.52 for U.S. residential, commercial, and industrial customers, respectively.

The utilities that estimate and use price elasticities that we reviewed mostly use their own data of varying time lengths to report elasticities as short-run, long-run or neither.[20] The number of years used in these studies vary from 3 to 30 years. Two cases where long-run price elasticities are reported and/or used are those of Fortis BC's second RIB impact study, which uses 4 years of data and reports the estimated elasticity as long-run, and a PacifiCorp study that uses long-run price elasticity estimates from the U.S. Pacific Coast to determine Class 3 DSM resource forecasts. Fortis BC considered two years of post-RIB period to be sufficiently long to allow for capital stock changes while the PacifiCorp study used long-run price elasticities to determine long-term (20 years) demand reductions from voluntary participation in time-varying rates (Class 3 DSM resources). All other elasticities deemed as either short-run or neither short- or long-run are applied to either

[20] We note that several utilities we reviewed (Newfoundland Power, New Brunswick Power, Nova Scotia Power, Yukon Energy, Public Service Company of Colorado (PSCo), Seattle City Light) use price elasticities of unknown origin and classified either as short-run or neither short- or long-run. These elasticities are used to forecast load.

assess rate impact or forecast load. The table below summarizes the number of years used in each study, the price elasticities estimated and where these estimates are applied.

Table 2: Data used in utility price elasticity estimates

UTILITY/STUDY	ELASTICITY	SECTOR	YEARS IN STUDY	CLASSIFICATION	APPLICATION
FORTIS BC	-0.086	Residential	3	short-run	rate impact
FORTIS BC	-0.160	Residential	4	long-run	rate impact
PUBLIC SERVICE NEW MEXICO	-0.06/-0.19	Residential	9	short-run	load forecast
PUBLIC SERVICE NEW MEXICO	-0.10/-0.20	Commercial	9	short-run	load forecast
SOUTHERN CALIFORNA EDISON	-0.170	Residential	15	short-run	rate impact
SAN DIEGO GAS & ELECTRIC	-0.100	Residential	not provided	short-run	rate impact
PORTLAND GENERAL ELECTRIC	-0.100	Residential	> 20	not classified	load forecast
PORTLAND GENERAL ELECTRIC	-0.030	Non-residential	> 20	not classified	load forecast
NV POWER/CARAVALLO ET AL. STUDY	-0.100	Residential	> 20	not classified	load forecast
PUGET SOUND/CARAVALLO ET AL. STUDY	-0.190	Residential	> 10	not classified	load forecast
PUGET SOUND/CARAVALLO ET AL. STUDY	0.160	Commercial	> 10	not classified	load forecast
PUGET SOUND/CARAVALLO ET AL. STUDY	-0.190	Industrial	> 10	not classified	load forecast
AVISTA/CARAVALLO ET AL. STUDY	-0.150	Residential	not provided	not classified	load forecast
AVISTA/CARAVALLO ET AL. STUDY	-0.100	Commercial	not provided	not classified	load forecast
PACIFICORP/CARAVALLO ET AL. STUDY	-0.100	All classes	not provided	not classified	load forecast
PACIFICORP - U.S. PACIFIC COAST ESTIMATE/NREL STUDY	-0.10 to -0.40	Residential	> 20	long-run	DSM resource forecast

The foregoing indicates that price elasticities estimated based on data of similar duration are classified as short- or long-run or neither. There does not seem to be a discernible pattern as to what duration of data results in short- versus long-run price elasticity estimates in these studies.

As noted earlier, price elasticities estimated using historical utility data, where factors that impact capital stock such as energy efficiency policies and technological changes, have been in place for some time, reflect net price effects. This is because past DSM and related policy induced savings are captured in historical energy use, which is on a lower trajectory because of these initiatives.[21] Estimated price elasticities with time series data in such a setting do not confound DSM and rate change effects.

[21] In its 2016 load forecast, Nova Scotia specifies use per customer or sales models that include cumulative historical DSM savings as an explanatory variable to determine what level of DSM is already captured in the load forecast. A model coefficient of -1 indicates no historical DSM is in the forecast while a value of 0 indicates that the forecast already includes 100% of historical DSM and does not need to be adjusted by incremental DSM savings forecast. It found the coefficient to be -0.6 for the residential sector and -0.5 for the commercial and industrial sectors. These coefficients reflect that 40% and 50% of DSM savings are already accounted for in the residential and C&I load forecasts, respectively.

Recommendation: DNV GL supports BC Hydro's current approach of using methods other than price elasticity (e.g. direct adjustment for expected savings from energy efficiency and codes and standards) to account for capital stock turnover in load forecasts. This approach is consistent with a recommendation to BC Hydro by Dr. Orans in 2007, and we agree with his assessment that this method will minimize double counting. Our jurisdictional review did not find any evidence of other utilities applying both a short-run and long-run elasticity estimate to their load forecast in addition to adjustments for stock turnover such as DSM savings.

Flat rate analysis

BC Hydro informed DNV GL that it is examining the potential impacts of transitioning its residential inclining block rate to a flat rate. DNV GL reviewed a similar rate case in California where the IOUs proposed to move from a 4-tier inclining block rate to two-tiers and many stakeholders were concerned that it would negatively impact conservation. The IOUs solicited expert advice from Dr. Faruqui, a principal at the Brattle Group, who performed empirical analysis that indicated negative or minimal consumption impact from a transition to such rates. Rather than adopt a single approach to estimating the impact, Dr. Faruqui used 3 different methodologies (average price, marginal price, and tier-specific) to estimate the impact of the rate change. This multi-method approach resulted in outcomes ranging from a 2 percent decrease in consumption to a 1.7 percent increase in consumption with two of the three indicating a decrease for each IOU. The results indicated that the effect of removing the tiers was unlikely to cause a negative conservation effect.

Recommendation: DNV GL recommends that BC Hydro uses a similar multi-method approach to model the potential change in its rate design from an inclining block rate to a flat rate.

3 RECOMMENDATIONS FOR FUTURE RESEARCH

This section includes a summary of topics that may warrant future research depending on BC Hydro needs and priorities. These topics were identified as secondary objectives for this project and there are still gaps in the research.

- BC Hydro elasticity studies for the commercial and industrial sectors
- Cross-price elasticity (electric vs. gas)
- TOU rates and substitution elasticity including methods to disentangle demand changes and peak to off-peak reduction
- Price elasticity segmentation (region, dwelling type, consumption, heating fuel type, etc.)

4 SOURCE LIST

This section includes a list of documents and reports reviewed and used in this memo. The bibliography does not contain documents that were reviewed by DNV GL but were not used due to lack of relevant information. The literature review subsection includes academic reports and articles while the jurisdictional review subsection is organized by utility and includes the rate cases and load forecasting documents cited in this memo.

4.1 Literature Review

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4.2 Jurisdictional Review

Canadian Utilities

BC Hydro

BC Hydro 2008 Long Term Acquisition Plan, Appendix E: Direct Testimony of Dr. Ren Orans, 2008.

Electric Load Forecast Fiscal 2013 to Fiscal 2033, BC Hydro (Load and Marketing Forecasting, Energy Planning and Economic Development), 2012.

Evaluation of the Residential Inclining Block Rate, F2009-F2012 - Revision 2 (prepared by Power Smart Evaluation), 2014.

BC Hydro 2015 Rate Design Application, prepared for the British Columbia Utilities Commission, 2015.

Evaluation of the Large and Medium General Service Conservation Rates: F2014, BC Hydro (prepared by Prepared by Power Smart Evaluation), 2015.

British Columbia Hydro and Power Authority F2017 to F2019 Revenue Requirements Application: Key Findings– Load Forecast, 2017.

British Columbia Hydro and Power Authority – British Columbia Utilities Commission Inquiry Respecting Site C – Project No. 1598922 – Final Report, 2017.

Evaluation of the Residential Inclining Block Rate, Fiscal 2013 to 2017, BC Hydro (prepared by Conservation and Energy Management Evaluation), 2018.

Load Forecast Build Up and Monte Carlo Methodology, BC Hydro (internal document), 2018.

Fortis BC

Residential Conservation Rate Information Report for the Period July 1, 2012 to June 30, 2014 - British Columbia Utilities Commission (BCUC or the Commission) Orders G-182-13A and L-7-14 Compliance Filing, FortisBC Inc. (FBC), November 28, 2014.

2017 Cost of Service Analysis and Rate Design Application, FortisBC Inc. (FBC), December 22, 2017.

Manitoba Hydro

Residential Conservation Rate Information Report for the Period July 1, 2012 to June 30, 2014 - British Columbia Utilities Commission (BCUC or the Commission) Orders G-182-13A and L-7-14 Compliance Filing, FortisBC Inc. (FBC), November 28, 2014.

2017 Cost of Service Analysis and Rate Design Application, FortisBC Inc. (FBC), December 22, 2017.

Nova Scotia Power

Nova Scotia Power - An Emera Company 2016 Load Forecast Report, 2017 ACE CA IR-14 Attachment 1 of 2017 Annual Capital Expenditure Plan (NSUARB M07745), NSPI Responses to Consumer Advocate Information Requests, May 2, 2016.

Newfoundland Power

Newfoundland Power - 2016/2017 General Rate Application Volume, Customer, Energy and Demand Forecast, Newfoundland Power, October 2015.

New Brunswick Power

Information Package relating to New Brunswick Power Distribution and Customer Service Corporation forecasted revenues and costs for 2009/2010, IN THE MATTER OF an Investigation into the necessity for the three per cent increase in charges, rates and tolls of the New Brunswick Power Distribution and Customer Service Corporation pursuant to section 24 of the Energy and Utilities Board Act, 30 April, 2009.

SaskPower

Saskatchewan Rate Review Panel – Regarding the SaskPower 2017 Rate Application, Report to the Minister Responsible for Crown Investments Corporation of Saskatchewan, March 1, 2018.

Yukon Energy

Long Term Load and Demand Forecast Yukon Energy Corporation (YEC), Submitted to Yukon Energy Corporation by Itron, Inc., March 8, 2016.

U.S. Utilities

California IOUs (Pacific Gas & Electric Company, Southern California Edison, San Diego Gas & Electric)

Joint Utility Rebuttal Testimony of Dr. Ahmad Faruqui on Demand Elasticity and Conservation Impacts of Investor-Owned Utility Proposals, Pacific Gas and Electric Company Long-Term Residential Electric Rate Design Reform Proposal Phase 1, October 17, 2014.

California State-Wide

California Energy Demand 2018-2030 Revised Forecast, California Energy Commission, Commission Staff Report, Document No. 17-IEPR-03, 4/19/2018.

PacifiCorp

Assessment of Long-run, System-Wide Potential for Demand-Side and Other Supplemental Resources, 2013-032 Volume I, Prepared for PacifiCorp by the Cadmus Group, March 2013.

Portland General Electric

Before the Public Utility Commission of the State of Oregon, UE238, Portland General Electric Load Forecast – Direct Testimony of Ham Nguyen and Sarah Dammen, Direct Testimony and Exhibits of Ham Nguyen and Sarah Dammen, February 13, 2014.

Public Service Company of Colorado (Xcel)

Public Service Company of Colorado 2016 Electric Resource Plan Volume 2, CPUC Proceeding No. 16A-0396E, May 27, 2016.

Public Service Company of New Mexico

In the Matter of the Application of Public Service Company of New Mexico For a Revision of Its Retail Electric Rates Pursuant to Advice Notice Nos. 397 And 32 (Former TNMP Services) Case No. 10-00086-UT - Direct Testimony and Exhibits of Jonathan A. Lesser, PhD on Behalf of Public Service Company of New Mexico, June 1, 2010.

Puget Sound Energy

2017 Integrated Resource Plan, PSE, November, 2017.

Seattle City Light

2013 System Load Forecast, Seattle City Light Review Panel, December 6, 2013.

Memo to:
BC Hydro

From: DNV GL
Date: 9/6/18

Subject: Memo - GDP Findings and Recommendations

1 PROJECT OVERVIEW

BC Hydro hired DNV GL to provide an external review of how BC Hydro uses gross domestic product (GDP) in load forecast uncertainty analysis. This memo provides DNV GL's findings and recommendations on this topic.

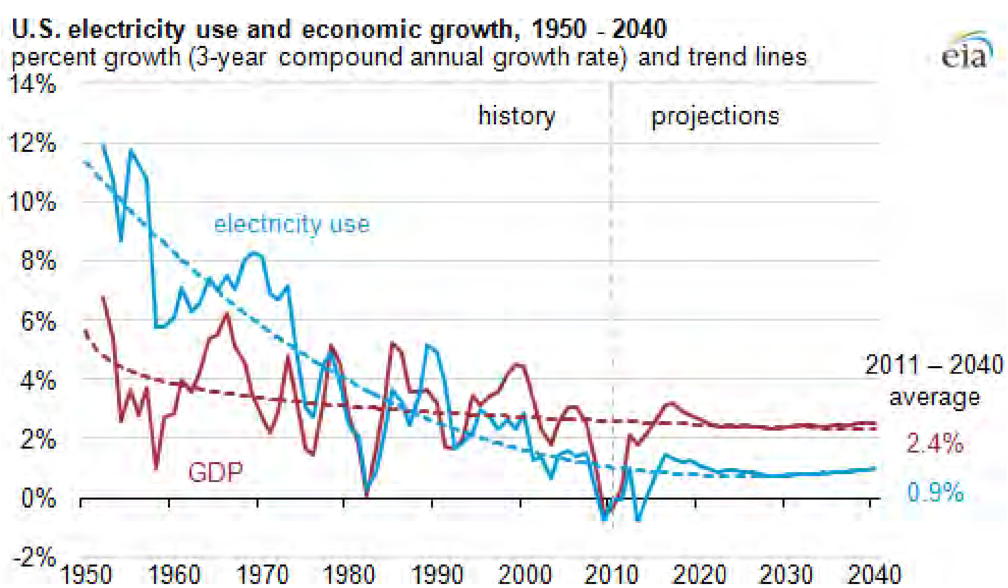
In this section, we provide a background discussion on the use of GDP in uncertainty analysis, details on project goals, and a description of DNV GL's approach. We discuss our research, findings, and recommendations in section 2. We outline a few next steps in section 3 and provide the sources used in the research in the final section.

1.1 Background

GDP/Uncertainty analysis

Regional GDP is a driver in parts of BC Hydro's distribution-connected load forecasting models. It is also a key driver of uncertainty bands for forecasted loads. Some research has shown the relationship between GDP and electricity usage is changing. The primary issue of concern to BC Hydro is whether and/or how GDP should continue to be used as a key driver in its uncertainty analysis, and what possible options there may be for adjusting or augmenting the GDP variable.

While the long-run relationship is changing, there is still a short-run correlation between GDP and electricity usage. The following chart, utilizing US data, demonstrates both long-run and short-run effects. Some key reasons for the long-run changes include responses to increasing electricity prices and technology change (which may also partly be tied to increasing electricity prices).



Source: U.S. Energy Information Administration, Annual Energy Outlook 2013 Early Release

Since the BC Hydro uncertainty analysis includes electricity prices as a variable, it is likely that it is at least partly capturing some of the reasons for the changing GDP/load relationship. In addition, since GDP also correlates well with electricity use in the short-run, GDP still may be a reasonable variable to include in an uncertainty analysis. There also may be variables that better capture the relationship between economic/demographic growth than GDP. For example, one could possibly break out GDP into 2 components – population and GDP per capita.

1.2 Goals and Approach

The objective of this project was to examine if the use of regional GDP in load forecast uncertainty is justified. DNV GL undertook a literature review to document the use of GDP and other economic variables in load forecast uncertainty. In collaboration with BC Hydro, DNV GL selected utilities in Canada and the United States to include in a literature review.[1]

The overall objective of this undertaking is to provide BC Hydro with recommendations on how to improve uncertainty analysis considering possible decoupling of GDP from electricity growth, keeping in mind that one possible recommendation could be to do nothing.

2 GDP/UNCERTAINTY ANALYSIS

This section presents the GDP and uncertainty analysis findings from DNV GL's literature and jurisdictional review. In section 2.1, we briefly describe BC Hydro's current use of GDP as a key input in its load forecasting process and uncertainty analysis. Section 2.2. provides an overview of how other utilities use GDP in load forecasting and uncertainty analysis. Finally, DNV GL presents recommendations for BC Hydro in section 2.3.

2.1 BC Hydro

One of the key drivers in BC Hydro's commercial and industrial load forecast is provincial GDP. Load forecasting is inherently uncertain as electricity demand is influenced by several difficult to measure and ever-changing factors like weather, technology, DSM programs, consumer behavior and market conditions for the largest customers. To quantify uncertainty in its load forecast, BC Hydro uses a Monte Carlo model and simulation technique. It uses variables of economic growth (measured by GDP), price of electricity (rates), heating degree days to represent the impact of temperature, elasticity of load (with respect to GDP and price), and it has 4 major distributions for the large industrial sector as major inputs in the simulation. In addition, BC Hydro includes uncertainty in electric vehicle adoptions, DSM, and codes and standards changes in the Monte Carlo model. Put simply, the model takes many random samples from the input scenarios to simulate output values that are used to construct the range and probability of sector level demand.

BC Hydro addresses the impact of GDP uncertainty in its load forecast in two ways. First, it addresses uncertainty in economic output by modeling a range of GDP scenarios. To do this, BC Hydro starts with the first-year base case GDP, which then grows at a rate equal to the base case growth rate plus a random perturbation amount. Second, BC Hydro addresses the uncertainty in consumer response to economic growth

[1] Same list of utilities as jurisdictional review included in 2015 BC Hydro rate design application.

by using triangular probability distribution around its GDP elasticity estimates. Currently, BC Hydro assumes a mean GDP elasticity of 0.67 for the residential sector and 0.78 for the commercial and industrial general service sectors.

2.2 Other jurisdictions

It appears that all the utility studies we reviewed (presented below) use GDP or some proxy for regional economic activity as a variable in their load forecast. Additionally, information on load forecast uncertainty analysis, where present, indicates the use of GDP to model the effect of different economic scenarios on load forecast. DNV GL did not find an example of a utility using alternatives to GDP to forecast or examine load forecast uncertainties. These findings suggest it's reasonable to use GDP in load forecasting and uncertainty analysis. Lastly, DNV GL would like to highlight the Manitoba Hydro and California state-wide approaches that use GDP in load forecasting and uncertainty analysis discussed below, as they are particularly informative and applicable for BC Hydro.

Nova Scotia Power

- Provincial GDP and employment used in SAE models to forecast small and general service commercial sector load
- No GDP elasticity term used in these end use models, which presumes a 1-to-1 correspondence between economic activity and commercial end-use
- Provincial GDP, exports, and manufacturing employment used in econometric models to forecast small and medium industrial sector load
- Large general service and industrial class loads forecast based on a combination of customer survey and historical sales information

New Brunswick Power

- General service (commercial) forecast based on an econometric model that relates changes in the level of sales to changes in provincial GDP, HDD, real price of electricity and previous year's sales level
- Industrial forecast also based on an econometric model where change in industrial use is based on change in GDP
- No details on GDP elasticity

Yukon Energy

- Commercial forecast based on SAE models include the effect of non-mining provincial GDP
- Industrial forecast is generated by a generalized economic model using forecasts for specific proxy mines
- No details on GDP elasticity

PSCo

- Gross State Product used in commercial and industrial end use models.

- Elasticity value of 0.7 used in these models.

Portland General Electric

- Real GDP and Oregon non-farm payroll employment used in PGE's regression forecast models
- No details on GDP elasticity

PSE

- Econometric models of residential, commercial, and industrial use per customer based on demographic and economic variables including GDP to forecast load
- No details on GDP elasticity, but expected high and low GDP growth scenarios used in uncertainty analysis

Manitoba Hydro

- Expert testimony indicates the relationship between GDP and electricity use has been weakening in advanced economies due to changes in the composition of their economies, where the share of manufacturing in GDP has been declining, and energy efficiency efforts
  - Energy intensity, quantity of energy used to produce a single dollar of GDP, declining by 1% per year in these economies since 1990
  - In Canada, energy intensity declining by more than 1% per year while energy use per capita is flat
- Nevertheless, electricity use still closely related to GDP with GDP elasticity of 0.8 (1% increase in GDP associated with 0.8% increase in electricity use)

CA state-wide

- Industrial model of energy demand driven by GDP or gross state product, employment and capacity utilization rates
- No details on GDP elasticity, but high, mid and low forecast scenarios include assumptions about high, low and medium economic growth
- Uncertainty analysis also includes variability in energy savings from energy efficiency programs, PV adoptions/self-generation, and electric vehicle (EV) adoptions

2.3 GDP conclusion and recommendations

As we mentioned in section 1.1, there is some indication of a decoupling between GDP and electricity use over the long-run. Partly this reflects declines in energy intensity due to structural changes in advanced economies, which have been undergoing de-industrialization. In addition, other factors such as increased energy prices and utility/government intervention via energy efficiency programs are responsible for the notable decoupling of GDP and electricity use. However, there is still a strong correlation in short-run variation between electricity use and economic activity most commonly measured by GDP. For a given set of explanatory variables (such as price and weather), variations in GDP growth will still have significant impacts on electricity demand growth.

Given that some of these variables (i.e. price) are also included in the uncertainty analysis, it seems reasonable to use variations in GDP growth in uncertainty analysis as well. The use of elasticities that are below 1.0 also makes sense and accounts for the fact that there is likely a fixed component of electricity use that would be present at most reasonable levels of GDP and ensures that a doubling of GDP won't translate into a doubling of electricity use.

As the jurisdictional review findings indicate, all of the utilities we reviewed use GDP or some proxy for regional economic activity as a variable in their load forecast. We did not find any evidence of new or alternative approaches for BC Hydro to consider.

Recommendation: We've concluded that the approach BC Hydro utilizes for addressing uncertainty in load forecasts by using variations in GDP growth and elasticity is reasonable and DNV GL recommends that BC Hydro continue its current approach. At the outset of this exercise we acknowledged that a possible outcome would be a recommendation to "do nothing" and based on our focused but limited research on the topic that is our current recommendation.

3 RECOMMENDATIONS FOR FUTURE RESEARCH

DNV GL recommends further investigation of the impact of splitting GDP into separate variables (population and GDP per capita) on load forecast uncertainty analysis. This is a topic of some relevance, but not one addressed in this research undertaking.

4 SOURCE LIST

This section includes a list of documents and reports reviewed and used in this memo. The bibliography does not contain documents that were reviewed by DNV GL but were not used due to lack of relevant information.

4.1 Jurisdictional Review

Canadian Utilities

BC Hydro

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Electric Load Forecast Fiscal 2013 to Fiscal 2033, BC Hydro (Load and Marketing Forecasting, Energy Planning and Economic Development), 2012.

Evaluation of the Residential Inclining Block Rate, F2009-F2012 - Revision 2 (prepared by Power Smart Evaluation), 2014.

BC Hydro 2015 Rate Design Application, prepared for the British Columbia Utilities Commission, 2015.

Evaluation of the Large and Medium General Service Conservation Rates: F2014, BC Hydro (prepared by Prepared by Power Smart Evaluation), 2015.

British Columbia Hydro and Power Authority F2017 to F2019 Revenue Requirements Application: Key Findings–Load Forecast, 2017.

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British Columbia Hydro and Power Authority – British Columbia Utilities Commission Inquiry Respecting Site C – Project No. 1598922 – Final Report, 2017.

Evaluation of the Residential Inclining Block Rate, Fiscal 2013 to 2017, BC Hydro (prepared by Conservation and Energy Management Evaluation), 2018.

Load Forecast Build Up and Monte Carlo Methodology, BC Hydro (internal document), 2018.

Fortis BC

Residential Conservation Rate Information Report for the Period July 1, 2012 to June 30, 2014 - British Columbia Utilities Commission (BCUC or the Commission) Orders G-182-13A and L-7-14 Compliance Filing, FortisBC Inc. (FBC), November 28, 2014.

2017 Cost of Service Analysis and Rate Design Application, FortisBC Inc. (FBC), December 22, 2017.

Manitoba Hydro

Residential Conservation Rate Information Report for the Period July 1, 2012 to June 30, 2014 - British Columbia Utilities Commission (BCUC or the Commission) Orders G-182-13A and L-7-14 Compliance Filing, FortisBC Inc. (FBC), November 28, 2014.

2017 Cost of Service Analysis and Rate Design Application, FortisBC Inc. (FBC), December 22, 2017.

Nova Scotia Power

Nova Scotia Power - An Emera Company 2016 Load Forecast Report, 2017 ACE CA IR-14 Attachment 1 of 2017 Annual Capital Expenditure Plan (NSUARB M07745), NSPI Responses to Consumer Advocate Information Requests, May 2, 2016.

Newfoundland Power

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New Brunswick Power

Information Package relating to New Brunswick Power Distribution and Customer Service Corporation

forecasted revenues and costs for 2009/2010, IN THE MATTER OF an Investigation into the necessity for the three per cent increase in charges, rates and tolls of the New Brunswick Power Distribution and Customer Service Corporation pursuant to section 24 of the Energy and Utilities Board Act, 30 April, 2009.

SaskPower

Saskatchewan Rate Review Panel – Regarding the SaskPower 2017 Rate Application, Report to the Minister Responsible for Crown Investments Corporation of Saskatchewan, March 1, 2018.

Yukon Energy

Long Term Load and Demand Forecast Yukon Energy Corporation (YEC), Submitted to Yukon Energy Corporation by Itron, Inc., March 8, 2016.

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U.S. Utilities

California IOUs (Pacific Gas & Electric Company, Southern California Edison, San Diego Gas & Electric)

Joint Utility Rebuttal Testimony of Dr. Ahmad Faruqui on Demand Elasticity and Conservation Impacts of Investor-Owned Utility Proposals, Pacific Gas and Electric Company Long-Term Residential Electric Rate Design Reform Proposal Phase 1, October 17, 2014.

California State-Wide

California Energy Demand 2018-2030 Revised Forecast, California Energy Commission, Commission Staff Report, Document No. 17-IEPR-03, 4/19/2018.

PacifiCorp

Assessment of Long-run, System-Wide Potential for Demand-Side and Other Supplemental Resources, 2013-032 Volume I, Prepared for PacifiCorp by the Cadmus Group, March 2013.

Portland General Electric

Before the Public Utility Commission of the State of Oregon, UE238, Portland General Electric Load Forecast – Direct Testimony of Ham Nguyen and Sarah Dammen, Direct Testimony and Exhibits of Ham Nguyen and Sarah Dammen, February 13, 2014.

Public Service Company of Colorado (Xcel)

Public Service Company of Colorado 2016 Electric Resource Plan Volume 2, CPUC Proceeding No. 16A-0396E, May 27, 2016.

Public Service Company of New Mexico

In the Matter of the Application of Public Service Company of New Mexico For a Revision of Its Retail Electric Rates Pursuant to Advice Notice Nos. 397 And 32 (Former TNMP Services) Case No. 10-00086-UT - Direct Testimony and Exhibits of Jonathan A. Lesser, PhD on Behalf of Public Service Company of New Mexico, June 1, 2010.

Puget Sound Energy

2017 Integrated Resource Plan, PSE, November, 2017.

Seattle City Light

2013 System Load Forecast, Seattle City Light Review Panel, December 6, 2013.

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix R

BC Hydro Organizational Chart

BC Hydro
Power smart

- Executive Chair
  Ken Peterson
  - President & Chief Operating Officer
    Chris O'Riley
    - Executive Vice-President Site C
      Ken McKenzie
    - General Counsel
      Ken Duke
    - Senior Vice-President Integrated Planning
      Maureen Daschuk
      - Director Energy Planning & Analytics **Bill Clendinning**
      - Director Dam Safety **Bob Schubak**
      - Director Line Asset Planning **Ajay Kumar**
      - General Manager Engineering **Kirsten Peck**
      - Director Stations Asset Planning **Andy Darby**
      - Director Interconnections **Frank Lin**
    - Senior Vice-President Capital Infrastructure Project Delivery
      Al Leonard
      - Vice-President Project Delivery **Melissa Holland**
      - Director Indigenous Relations **Lindsay Thompson**
      - Director Environment **Karen Popoff**
      - Director Properties **Joanna Sofield**
    - Executive Vice-President Operations
      Mark Poweska
      - Director Line Field Operations **Lanny Sawchuck**
      - Director Stations Field Operations **Richard Brittin**
      - Director T&D System Operations **Paul Choudhury**
      - Director Generation System Operations **Heather Matthews**
      - Director Program & Contract Management **Bill Earis**
      - Director Distribution Design & Customer Connect **Charlotte Mitha**
      - General Manager Construction Services **Matt Wilson**
      - Project Director Operational Integration **Darin Thompson**
    - Senior Vice-President Safety
      David Lebeter
      - Director Safety System & Assurance **Duane Duhamel**
      - Director Learning & Development **Tracey Armatage**
      - Manager Field Safety Services **Dave Fox**
      - Manager Security & Emergency Management **Ben Peco**
      - Director Projects **Fiona Taylor**
    - Executive Vice-President Finance, Technology, Supply Chain & Chief Financial Officer
      David Wong
      - Chief Supply Chain Officer **Gurj Parmar**
      - Chief Information Officer **Kip Morison**
      - Chief Accounting Officer **Ryan Layton**
      - Vice-President Projects **Diane McSherry**
      - Director Finance Site C **Elizabeth Fletcher**
      - Director Audit Services **Albert Lagnado**
    - Executive Vice-President People, Customer & Corporate Affairs
      Janet Fraser
      - Vice President Customer Service **Keith Anderson**
      - Chief Human Resources Officer **Carolynn Ryan**
      - Director Conservation & Energy Management **Stephen Hobson**
      - Director Power Acquisitions & Contract Management **Rohan Soulsby**
      - Chief Communications Officer **Darwin Sauer**
      - Chief Regulatory Officer **Fred James**

Subsidiaries

Powerex Corp

Powertech Labs

December 13, 2018

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix S

Summary of Organizational Changes

A summary of the organizational changes that occurred since the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application are shown below.

Table S-1 Summary of Organizational Changes since Fiscal 2017 to Fiscal 2019 Revenue Requirements Application

Business Group in this Application	KBU in this Application	KBUs in Previous Application [1, 2]	Business Group in Previous Application
Integrated Planning	Energy Planning & Analytics	Energy Planning	Operations Support
		Asset Management & Distribution Engineering	Transmission, Distribution and Customer Service
	Dam Safety	No Change	Capital Infrastructure Project Delivery
	Station Asset Planning	Generation Asset Management	Training, Development and Generation
		Generation Maintenance	Training, Development and Generation
		Generation Operations	Training, Development and Generation
		Field & Grid Operations	Transmission, Distribution and Customer Service
		Asset Management & Distribution Engineering	Transmission, Distribution and Customer Service
	Line Asset Planning	Asset Management & Distribution Engineering	Transmission, Distribution and Customer Service
		Technology	Transmission, Distribution and Customer Service
	Interconnections and Shared Assets	Asset Management & Distribution Engineering	Transmission, Distribution and Customer Service

1 If a KBU from the Previous Application is listed multiple times, it means that departments or teams from that KBU were transferred to multiple KBUs in this application.

2 To provide additional detail, the former Corporate Affairs KBU is presented at the department level rather than the KBU level. The former Corporate Affairs KBU consisted of the Energy Planning, Business Planning and Risk, Human Resources, Business and Economic Development, Regulatory and Rates, Conservation and Energy Management, Policy and Reporting and Communications departments.

Business Group in this Application	KBU in this Application	KBUs in Previous Application [1, 2]	Business Group in Previous Application
		Generation & Transmission Engineering	Capital Infrastructure Project Delivery
	Engineering	Generation & Transmission Engineering	Capital Infrastructure Project Delivery
		Asset Management & Distribution Engineering	Transmission, Distribution and Customer Service
Capital Infrastructure Project Delivery	Project Delivery	Project Delivery	Capital Infrastructure Project Delivery
		Generation & Transmission Engineering	Capital Infrastructure Project Delivery
	Indigenous Relations	No Change (was Aboriginal Relations)	No Change
	Environment	No Change (was Environmental Risk Management)	No Change
	Properties	No Change	No Change
Operations	Program and Contract Management	Program and Contract Management	Transmission, Distribution and Customer Service
		Asset Management & Distribution Engineering	Transmission, Distribution and Customer Service
	Line Field Operations	Field & Grid Operations	Transmission, Distribution and Customer Service
	Stations Field Operations	Generation Maintenance	Training, Development and Generation
		Generation Operations	Training, Development and Generation
		Field & Grid Operations	Transmission, Distribution and Customer Service
	Distribution Design & Customer Connect	Customer Service & Distribution Design	Transmission, Distribution and Customer Service
	Construction Services	Field & Grid Operations	Transmission, Distribution and Customer Service

Business Group in this Application	KBU in this Application	KBUs in Previous Application [1, 2]	Business Group in Previous Application
	Generation System Operations	No Change (was Generation Resource Management)	Training, Development and Generation
	T&D System Operations	Field & Grid Operations	Transmission, Distribution and Customer Service
Safety	Safety System and Assurance	Safety, Security and Emergency Management	Operations Support
		Training and Development	Training, Development and Generation
	Learning and Development	Training and Development	Training, Development and Generation
		Safety, Security and Emergency Management	Operations Support
	Field Safety Services	Safety, Security and Emergency Management	Operations Support
		Field & Grid Operations	Transmission, Distribution and Customer Service
	Security and Emergency Management	Safety, Security and Emergency Management	Operations Support
Finance, Technology, Supply Chain	Finance	Finance and Supply Chain	Operations Support
		Business Planning and Risk	Operations Support
	Technology	Technology	Transmission, Distribution and Customer Service
		Field & Grid Operations	Transmission, Distribution and Customer Service
	Supply Chain	Finance and Supply Chain	Operations Support

Business Group in this Application	KBU in this Application	KBUs in Previous Application [1, 2]	Business Group in Previous Application
People, Customer and Corporate Affairs	Human Resources	Human Resources	Operations Support
		Training and Development	Training, Development and Generation
	Customer Service	Customer Service & Distribution Design	Transmission, Distribution and Customer Service
		Field & Grid Operations	Transmission, Distribution and Customer Service
	Conservation and Energy Management	No Change	Operations Support
	Power Acquisitions and Contract Management	No Change (was Business and Economic Development)	Operations Support
	Communications and Community Engagement	Communications	Operations Support
		Policy and Reporting	
	Regulatory and Rates	No Change	Operations Support
	Ethics and Merit Office	SVP, Corporate Affairs	Operations Support
Other	Office of the General Counsel	General Counsel	Operations Support
	Office of the President and Chief Operating Officer	Executive	Operations Support

BC Hydro
Power smart

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix T

Brattle Group Benchmarking Study

BEFORE THE

BRITISH COLUMBIA UTILITIES COMMISSION

BC Hydro Fiscal 2020—Fiscal 2021 Revenue Requirements Application to the British Columbia Utilities Commission

EXPERT REPORT

OF

WILLIAM P. ZARAKAS

ON BEHALF OF

BC Hydro

February 8, 2019

TABLE OF CONTENTS

Appendices A through D follow.

BEFORE THE

BRITISH COLUMBIA UTILITIES COMMISSION

BC Hydro Fiscal 2020—Fiscal 2021 Revenue Requirements Application to the British Columbia Utilities Commission

EXPERT REPORT OF WILLIAM P. ZARAKAS

I. INTRODUCTION AND SUMMARY OF OPINION

1. BC Hydro asked The Brattle Group (Brattle) to conduct a cost benchmarking study of its operations and maintenance costs, excluding the costs of fuel and water rentals that are used in the power production process. These costs are frequently referred to as non-fuel operations and maintenance expenses (NFOM) and do not include capital costs that may be involved in building out new utility plants. I examined BC Hydro's NFOM costs against a peer panel of U.S. investor-owned electric utilities, primarily because of the availability of consistent and publicly available accounting data available for these utilities. U.S. investor owned electric utilities are required to file an annual report each year with the Federal Energy Regulatory Commission (FERC) following the accounting guidelines included in the FERC's Uniform System of Accounts (USoA).

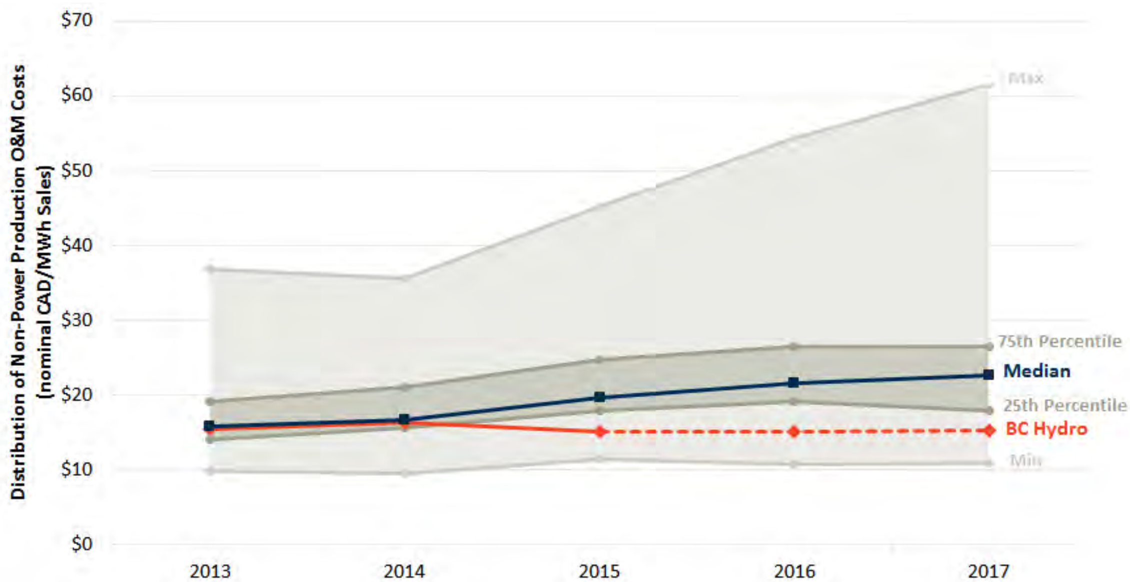
2. BC Hydro does not currently track its cost data following the USoA. In order to complete this cost benchmarking study, BC Hydro's accounting department reviewed accounting records and provided Brattle with the company's NFOM costs in USoA format. NFOM cost data in the USoA format were not available from other Canadian electric utilities. If so, some of these utilities would have also been included in the electric utility peer panel.

3. BC Hydro's total NFOM costs (on a per delivered MWh basis) are in the 1st quartile of the peer panel, the preferred position with respect to cost efficiency. However, in this particular case, I find that the measure of total NFOM is less informative than the disaggregated benchmarking results (for non-power production NFOM and power production NFOM), which are presented below. This is primarily due to BC Hydro's unique position with respect to comparable power production NFOM, which has a

strong influence on the total NFOM metrics. Nonetheless, in a "bottom line" sense, across the years included in the study, BC Hydro's overall NFOM unit cost is lower than nearly all of the U.S. utilities included in the peer panel.

4. The majority of BC Hydro's annual NFOM costs (more than 80%) are associated with its non-power production operations; i.e., transmission, distribution, customer service, and administrative and general functions. As demonstrated in Figure 1, the benchmarking analysis indicates that BC Hydro's costs (on a per delivered MWh basis) in this area are lower than most utilities included in the peer panel, and are frequently in the 1st quartile of the panel. As will be discussed in the main body of the report, my conclusions are similar if the benchmarking exercise is instead conducted on a $ per customer basis.

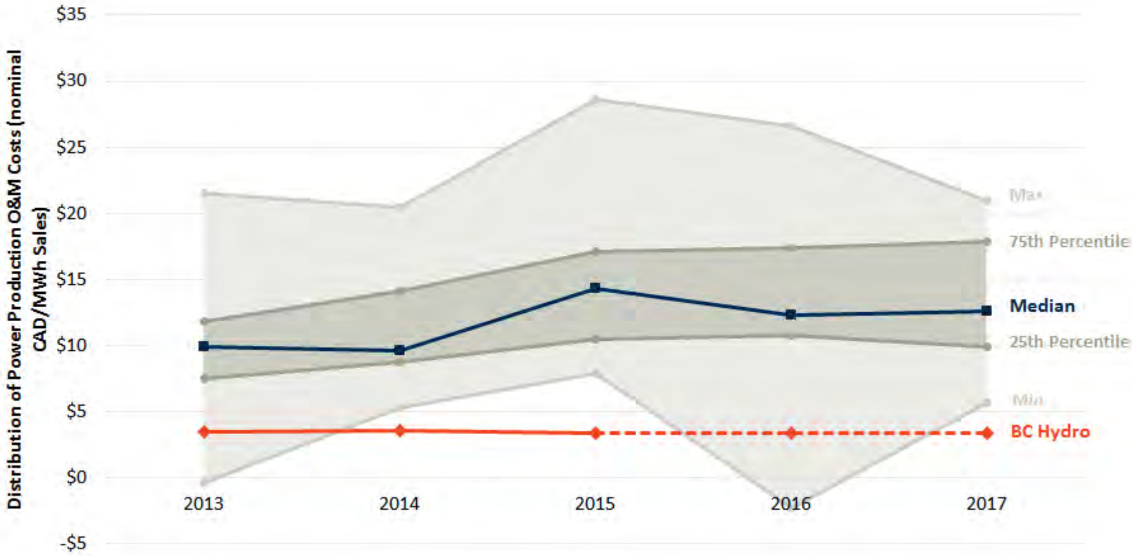
Figure 1: Non-Power Production NFOM ($ per Delivered MWh)



Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (pp. 321–323) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

5. As shown in Figure 2 below, BC Hydro's power production NFOM costs (on a per generated MWh basis) are significantly lower than the U.S. utility peer panel. This is likely because the majority of BC Hydro's power plants are large scale hydroelectric plants, while peers in the panel generally own fewer and smaller scale hydro units. In addition, the peer utilities' power production portfolios are generally comprised of predominantly thermal units. Together, these factors likely contribute to peers having higher operations and maintenance costs than do BC Hydro's large scale hydro plants.

Figure 2: Power Production O&M Cost Benchmarking ($ per Generated MWh)



Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (pp. 320–321 and 401a), downloaded from Velocity Suite.

II. QUALIFICATIONS

6. I am William P. Zarakas. I am a Principal with The Brattle Group, an economics consulting firm. I was assisted by colleagues at The Brattle Group in conducting this benchmarking study, and have asked other Principals with expertise in cost analysis and total factor productivity analysis to review this report. While I benefited from the assistance and reviews provided by my colleagues, I alone am responsible for the contents and conclusions in this expert report.

7. I hold a leadership position in Brattle's Retail Energy Practice, and I lead much of Brattle's project work in the areas of performance based regulation, cost analysis and benchmarking, utility business models, benefit-cost analyses (e.g., grid modernization, reliability and resilience) and rate and pricing analyses. I also work on economic and regulatory matters in the telecommunications industry, including the economics and financial feasibility of building-out broadband infrastructure and regulatory matters concerning network access and pricing.

8. I have provided testimony and expert reports on matters concerning electric utility regulatory frameworks and approaches and cost analyses, as well as competition and

regulatory issues in the telecommunications industry. My testimony and expert reports have been presented before the Federal Energy Regulatory Commission (FERC), state regulatory commissions, the Federal Communications Commission (FCC), the Securities and Exchange Commission (SEC), the Copyright Royalty Judges (Library of Congress), the U.S. Congress, arbitration panels, and courts of law. I have also authored reports concerning special investigations on behalf of corporate boards of directors and audits of management practices and operational and financial performance on behalf of regulatory commissions.

9. I hold an M.A. in economics from New York University and a B.A., also in economics, from the State University of New York. I have authored articles in industry periodicals and journals on economic and regulatory matters. I have also taken and instructed courses on economic and regulatory matters. My curriculum vitae is provided in Appendix A.

III. DUTY OF INDEPENDENCE

10. I understand that while I have been hired by BC Hydro, I have a duty to assist the Commission and that I am not to be an advocate for BC Hydro or any other party ("Duty of Independence").

11. I certify that I am aware of my Duty of Independence, and that I have prepared my report in accordance with that Duty of Independence. Furthermore, I certify that if I am called to give oral or written testimony, I will give that testimony in conformity with the Duty of Independence.

IV. ISSUES

12. BC Hydro has asked me to provide my independent objective opinions on the following issues:[1]

    1. What would be the appropriate metrics for benchmarking BC Hydro's overall base operating costs and why?

[1] The questions that BC Hydro requested me to opine upon in my report were summarized in a letter of instruction, dated December 3, 2018, which has been provided as Appendix B to my report.

2. What would be an appropriate representative peer group for benchmarking BC Hydro's base operating costs and why?
3. What data is available from the selected peer group on the selected metrics over the last three or five years?
4. What methodology should be used to normalize the data and benchmark BC Hydro's base operating costs against its peer group?[2]
5. What are the results of this normalization and benchmarking analysis?

V. DISCUSSION

13. I have organized the remainder of my report in three sections. In this section, I provide: background on cost benchmarking and a description of the approach used for this study; a summary of BC Hydro's NFOM costs (the primary subject of this benchmarking analysis); the cost benchmarking metrics used; the peer panel selected; and, a description of the data set of comparable U.S. electric utilities. I then briefly discuss the methodology used and present the results of the cost benchmarking analysis in Section VI, and provide overall conclusions in Section VII.

A. BENCHMARKING CONTEXT

14. BC Hydro has asked me to perform a benchmarking analysis of its base operating utility costs against the comparable costs for a peer panel of U.S. electric utilities.[3] These costs include all operating and maintenance expenses excluding the cost associated with fuel, and are sometimes referred to as non-fuel O&M costs, or NFOM.[4] In its most basic sense, cost benchmarking involves comparing the cost performance of a subject utility with comparable peers. Accordingly, cost benchmarking requires

2 I discuss the components of base operating costs in Section V.

3 Annual cost data for U.S. investor owned electric utilities are publically available because each utility is required to file an annual report (Form 1) with the Federal Energy Regulatory Commission (FERC) with cost categorized into standardized accounts as defined in FERC's Uniform System of Accounts (USOA). To my knowledge, such reporting is not required for Canadian electric utilities. I understand that BC Hydro is compiling and examining the comparative costs of certain Canadian electric utilities. These cost data were not directly available to me at the time that I was conducting this benchmarking analysis and were therefore not included here.

4 For BC Hydro, fuel costs also include the cost of water rentals that are used in the generation of power.

standardization (to the extent possible) of cost categories and also involves selecting peers that are similar to the utility being examined.

15. Effective cost benchmarking requires that both elements—accounting standardization and the comparability of peers—are adhered to as closely as possible. However, it is widely recognized that inconsistencies in data and/or peers are inevitable. Furthermore, even when data and peers are well-matched, exogenous events and/or extenuating circumstances may impact comparative cost performance. Thus, benchmarking results do not necessarily indicate whether a utility's cost performance is due to managerial and/or operational efficiencies. Gaining an understanding of causation requires additional analysis and more thorough investigation, and is beyond the scope of this study.[5]

16. I undertook this benchmarking study in "layers," starting by comparing BC Hydro's total NFOM with peer utilities. I then de-composed the total cost into components: power production NFOM and non-power production NFOM, and then the components that made up non-power production NFOM. (The more detailed aspects of my analysis—the components of non-production NFOM are provided in Appendix D.)

B. BC HYDRO NFOM COSTS

17. BC Hydro provided me with a breakdown of O&M costs for 2013 through 2015 following the uniform systems of accounts (USoA) that are used by U.S. investor owned electric utilities.[6] I understand that BC Hydro began its derivation of these costs by examining its total cost of operations as provided in its Consolidated Statement of Operations (included in BC Hydro's annual reports).[7] For 2015, BC Hydro's total

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5 Also, cost benchmarking, such as the NFOM discussed herein, reflect O&M costs only and assume that assets and facilities are already in place. NFOM cost benchmarking does not include capital costs, such as those involved in building new facilities. These latter costs are included in other types of cost and productivity analyses, such as calculations of total factor productivity (TFP).

6 BC Hydro annual data, as reported in its annual reports and as provided to me by company representatives, are based on its fiscal year (April 1 through March 31). For the remainder of the report, any reference to 2013, for example, refers to BC Hydro's fiscal year 2014, which covers April 1, 2013 through March 31, 2014. When referring to 2013 data for a U.S. utility, 2013 will correspond to calendar year 2013 (January 1, 2013 through December 31, 2013). I have adopted the same convention for all relevant years.

7 British Columbia Hydro and Power Authority 2015/16 Annual Service Plan Report, p. 27.

operating expenses were $5.002 billion. These expenses included: 1) roughly $1.9 billion reflecting its cost of energy, which includes purchases of electricity and gas, water rentals, and transmission charges; 2) roughly $1.2 billion in amortization; and 3) about $1.0 billion in finance expenses and grants, taxes and other costs. The remaining $905 million in 2015 were expenses associated with personnel, materials, and external services (PMAES) that reflect the utility's expenses associated with operating and running its utility system, which encompasses its generating stations and transmission and distribution assets, as well as its corporate, back office, and customer facing operations.

18. In order to benchmark these costs with peer U.S. utilities, BC Hydro adjusted these costs to be more in line with the NFOM costs included reported by U.S. utilities in the USoA, which involved two work steps completed by BC Hydro's accounting department. First, BC Hydro added and subtracted various cost categories to and from the expenses in its Consolidated Statement of Operations, primarily associated with reversing (for purposes of this exercise) certain deferral accounts and capitalized overheads and transfers to capital accounts, as well as removing that portion of expenses affiliated with Powerex and Powertech.[8] The adjusted NFOM that BC Hydro indicated was appropriate to use in this cost benchmarking study was $1.062 billion in 2015.[9] Second, BC Hydro broke this adjusted total NFOM into functional cost areas (e.g., annual O&M expenses for the power production, transmission, distribution, customer facing, and administrative and general).

19. BC Hydro has completed its accounting breakdown of functional costs for the years 2013–2015. However it currently only has accounting records for NFOM at the total level (i.e., not broken down by functional cost area) for 2016 and 2017; I have estimated the break down into functional cost areas based on historic percentages. BC Hydro confirmed this approach was reasonable. I show below (in Figure 3) that the percentage breakdown for functional cost for 2013, 2014, and 2015 are quite stable on a

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8 Powerex Corp. and Powertech Labs Inc. are the wholly owned subsidiaries of BC Hydro.

9 The adjusted NFOM was $1.001 billion for 2013 and $1.022 billion for 2014.

year-to-year basis. A breakdown by functional costs for 2013 through 2017 is shown in Figure 3 below.

Figure 3: BC Hydro NFOM Costs By Major Functional Cost Area ($ Millions)

Functional Cost Area	2013	2014	2015	2016	2017
Power Production	$184	$185	$194	*$194*	*$193*
Transmission	$150	$161	$165	*$165*	*$164*
Regional Market	$0	$0	$0	*$0*	*$0*
Distribution	$176	$178	$186	*$187*	*$186*
Customer Accounts	$74	$75	$75	*$78*	*$77*
Customer Service and Informational	$4	$4	$6	*$5*	*$5*
Sales	$0	$0	$0	*$0*	*$0*
Administrative and General	$412	$420	$437	*$439*	*$436*
Total	**$1,001**	**$1,022**	**$1,062**	**$1,067**	**$1,061**

Sources and Notes: Calculations by The Brattle Group, based on Uniform System of Accounts data provided by BC Hydro. The 2016 and 2017 values highlighted in light grey are estimates based on each cost area's average share of total NFOM from 2013 through 2015.

C. Appropriate Metrics for the Benchmark Analysis

20. I was asked by BC Hydro to determine appropriate metrics for benchmarking BC Hydro's base operating costs. Cost benchmark metrics are the measures through which comparative cost performance are conveyed because, even for similarly situated utilities, absolute dollar costs tend to convey little information with regards to comparable cost performance. Benchmark comparisons are typically made on a unit basis, such as the cost per MWh or cost per customer. Additional unit measures may be used, depending on the purpose of the benchmarking exercise and the availability of data.

21. Benchmarking studies undertaken for purposes of process improvement may be based on more granular and detailed metrics, such as the cost of tree trimming per circuit mile. However, such benchmarking typically requires that utilities supplement their public filings with additional and usually proprietary data.[10] The subject study was undertaken in order to gain a more general understanding of BC Hydro's comparative

[10] Such detailed operating level cost benchmarking studies usually involve a group of utilities agreeing to share detailed data, usually in a masked fashion. The processing of data and presentation of results are usually conducted by an independent party.

costs of operations, and thus did not involve this level of data granularity. Furthermore, data for comparable utilities were limited to public data sources, also serving to limit the depth of possible metrics.

22. I use three primary benchmark metrics in this study, each of which is widely used and considered "standard" for use in cost benchmarking analyses: 1) cost per *delivered* MWh; 2) cost per *generated* MWh; and 3) cost per (end-use) customer. MWh (a measure of throughput) and number of customers are complementary indicators of system size; they are frequently, but not always, correlated. Delivered and generated MWh each measure different points on the utility value chain. Delivered MWhs are related to the throughput received by end-use customers (and are thus appropriate as a metric for delivery functions, such as distribution functional costs), while generated MWh reflect the energy at the production facility (and are appropriate as a metric for power production costs). BC Hydro's delivered and generated MWhs and customer count for 2013 through 2017 are shown in Figure 4 below:

Figure 4: BC Hydro Benchmark Metrics (Denominators)

Year	Delivered GWh	Generated GWh	Customer Count
2013	53,018	45,596	1,914,549
2014	51,213	41,443	1,935,068
2015	57,300	49,567	1,960,555
2016	57,652	48,810	1,987,963
2017	57,173	48,017	2,018,044

Sources: British Columbia Hydro and Power Authority Annual Service Plan Reports for 2013/14, 2014/15, 2015/16, 2016/17, and 2017/18.

D. PEER PANEL

23. The utilities that are cost benchmarked against BC Hydro are referred to as a "peer panel." Ideally, the utilities included in a benchmarking peer panel should be relatively similar to the utility under study, however, perfect matches are rarely achieved. Nonetheless, selecting a reasonable peer panel is a particularly important part of cost benchmarking—for somewhat obvious reasons. Selecting inefficient or otherwise high cost utilities for a peer panel—intentionally or otherwise—may make the utility under study appear more efficient than it actually is, and vice versa. Accordingly,

considerable attention is afforded the peer panel selection process. Generally, peers are selected based on similar situations, with factors including its density and geography, number of customers and sales, number of utility employees, and terrain, weather, and climate.[11] These factors tend to affect the size and complexity of a utility's distribution system as well as its back office, administrative, and customer facing operations. Selecting peers based on similar situations is particularly important when the benchmarking object is the absolute level of costs, as is the case in my analysis, as opposed to changes in costs over time, such as is the object in productivity analysis. In the former case, differences in customer density, geography, weather, *etc*. will likely lead to significant differences in the absolute level of costs per unit of output. In contrast, in the latter case, the relationship between customer density, geography, weather, *etc*. and productivity growth is ambiguous.

24. BC Hydro is a vertically integrated electric utility, which can have an impact on overall employee counts (compared to utilities that do not own and/or operate power production facilities). In addition, BC Hydro's power production is dominated by hydroelectric generation, which tends to have lower O&M costs than do thermal or nuclear units.

25. Review of U.S. utility data indicates that U.S. investor owned electric utilities have much smaller hydro power portfolios than does BC Hydro. There are roughly 100 GWs of conventional hydro capacity in the U. S., but most of it is owned and operated by governmental entities which do not directly serve customers (with the possible exception of some large industrial customers).[12] Only two U.S. entities—the U.S. Army Corp of Engineers and the U.S. Bureau of Reclamation—own and operate more

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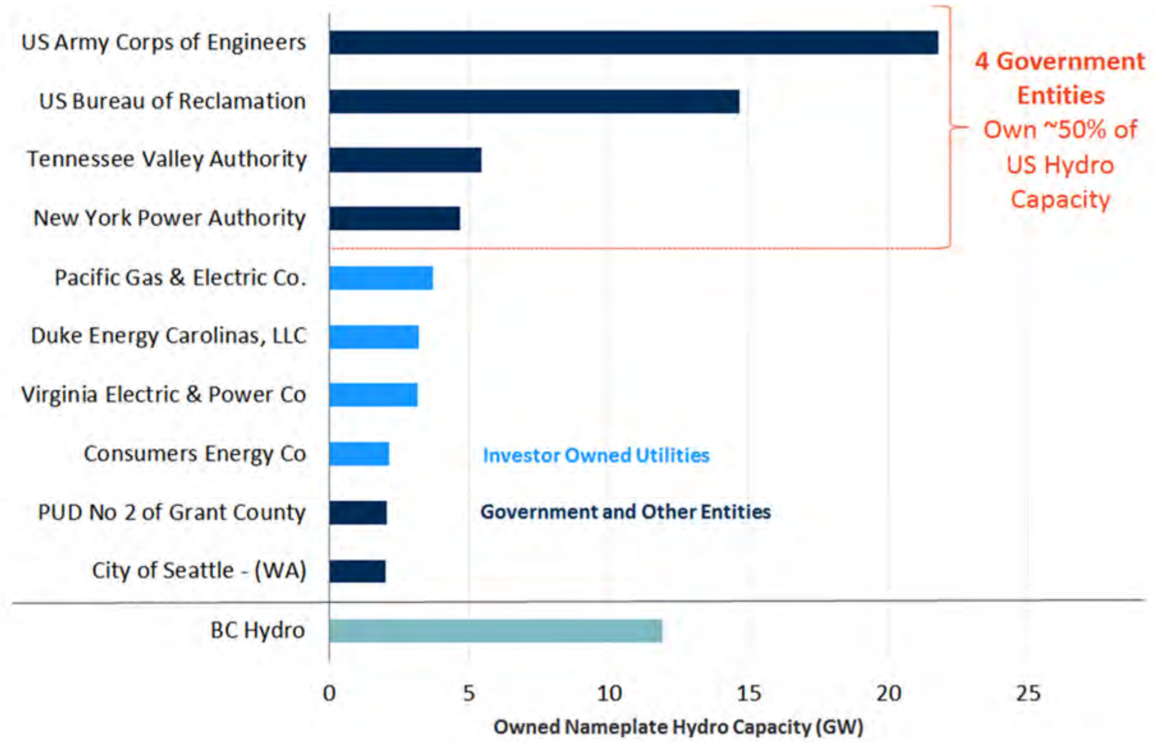
11 Specification of a peer panel may be driven by the intended use of the cost benchmarking exercise. For example, process improvement efforts sometimes deliberately select peer panels composed of very efficient firms, as these projects devote more effort in identifying ways for the subject company to improve performance than to assessing whether or not the company's spending levels are within prudent bounds.

12 For example, the 2017 Form EIA-860 Data – Schedule 3, "Generator Data" (Operable Units Only), available at: https://www.eia.gov/electricity/data/eia860/, indicated there were 101 GWs of conventional hydro capacity. Hereafter referred to as *2017 Form EIA-860 Data – Schedule 3.*

hydro capacity than does BC Hydro.[13] Figure 5 shows the top 10 entities (in terms of capacity) that own and/or operate hydro facilities in the U.S. Only three of these—Pacific Gas and Electric (PG&E), Duke Energy Carolina, Virginia Electric & Power Co. (Dominion), and Consumers Energy—are investor owned utilities.[14]

Figure 5: U.S. Entities Owning Large Amounts of Hydro Capacity



Sources: Data for BC Hydro are from the British Columbia Hydro and Power Authority 2017/18 Annual Service Plan Report. Data for U.S. Entities are from *2017 Form EIA-860 Data – Schedule 3.*

26. This makes it difficult to have a fully comparable peer panel on this dimension and, by extension, at a utility-wide level. However, it is possible (and meaningful) to benchmark costs at the functional level. To determine an appropriate peer panel, I

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13 Major hydro facilities owned by the U.S. Army Corp of Engineers include Oahe (which has a nameplate capacity of 784 MW), Richard B Russell (628 MW), Garrison (614 MW), Carters (500 MW), Big Bend Dam (494 MW), and Hartwell Lake (420 MW). Major hydro facilities owned by the U.S. Bureau of Reclamation include Grand Coulee (6,809 MW), Glen Canyon Dam (1,312 MW), Hoover Dam (2,079 MW), Shasta (714 MW), and Hungry Horse (428 MW). See *2017 Form EIA-860 Data – Schedule 3*. However, I do not include these two entities as part of my benchmarking peer group because they are federal entities that do not own or operate transmission or distribution systems and do not report USoA data.

14 Neither PG&E nor Consumers are considered vertically integrated utilities. Pacific Gas & Electric Co underwent restructuring in the late 1990s, divesting its gas-fired generation, and Consumers divested its transmission assets.

initially started with a dataset of all 120 U.S. investor owned electric utilities. Then I narrowed this list down to 23 U.S. utilities to form the peer panel for this study. These include 20 U.S. utilities that are vertically integrated and meet a minimum size requirement of delivering at least 20,000 GWhs to customers per year (for reference, BC Hydro delivered 57,652 GWhs to its customers in fiscal year 2018).[15] I also included three utilities that did not strictly meet these criteria because their generation mix included a substantial amount of hydro. The list of utilities included in the peer panel is shown in Figure 6. In addition, a spreadsheet of the utilities considered and screening criteria is attached as Appendix C.[16]

15 An additional utility also cleared this screen, Entergy Louisiana, LLC, which recently was involved in a merger with Entergy Gulf States Louisiana. This made it difficult to determine the cost data for 2013–2017 for the combined utility.

16 Appendix C provides the data set of 120 U.S. investor owned utilities used as the population to draw upon in selecting a peer panel for this study.

Figure 6: Cost Benchmarking Peer Panel

Utility	State/ Province	Services	Size of Service Area: Total Sales *TWh*	Size of Service Area: Total Customers *Thousands*	Capacity: Total Owned *GW*	Capacity: Hydro *% Total*	Supply: Total Source of Supply *TWh*	Supply: Hydro *% Total*	Supply: Power Purchases *% Total*
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
BC Hydro	**BC**	**E**	**57**	**2,018**	**13**	**92%**	**63**	**76%**	**23%**
Initial Benchmarking Screen									
Alabama Power Co	AL	E	54	1,475	13	14%	66	5%	9%
Ameren Missouri	MO	E/G	32	1,216	11	7%	44	5%	6%
Appalachian Power Co	VA	E	27	956	6	13%	36	3%	28%
Arizona Public Service Co	AZ	E	28	1,215	7	0%	33	0%	24%
Duke Energy Carolinas, LLC	NC	E	77	2,557	22	13%	92	5%	10%
Duke Energy Florida, LLC	FL	E	38	1,775	12	0%	43	0%	16%
Duke Energy Indiana	IN	E	27	820	7	1%	35	1%	20%
Duke Energy Progress	NC	E	43	1,559	14	2%	69	1%	11%
Entergy Arkansas, Inc	AR	E	21	709	6	1%	31	0%	14%
Florida Power & Light Co	FL	E	109	4,902	29	0%	124	0%	3%
Georgia Power Co	GA	E	82	2,501	17	7%	90	2%	30%
MidAmerican Energy Co	IA	E/G	24	770	9	0%	34	0%	10%
Nevada Power Co	NV	E	21	1,018	5	0%	24	0%	29%
Northern States Power Co - MN	MN	E/G	34	1,466	8	0%	48	0%	27%
Oklahoma Gas & Electric Co	OK	E/G	26	838	8	0%	29	0%	37%
PacifiCorp	UT	E	55	1,867	12	9%	67	7%	21%
Public Service Co of Colorado	CO	E/G	29	1,459	5	6%	38	1%	42%
Puget Sound Energy Inc	WA	E/G	21	1,135	4	7%	29	3%	62%
South Carolina Electric & Gas Co	SC	E/G	22	716	5	15%	24	2%	20%
Virginia Electric & Power Co	VA	E	81	2,575	18	11%	86	4%	14%
Hydro-Intensive IOUs									
Avista Corp	WA	E/G	9	382	2	54%	12	32%	40%
Idaho Power Co	ID	E	15	540	4	47%	18	50%	24%
Pacific Gas & Electric Co	CA	E/G	62	4,546	8	48%	69	17%	50%

Sources and Notes: Utility characteristics are reported for 2017. BC Hydro's sales, customer count and capacity data are from the BC Hydro's2017/18 Annual Service Plan Report. BC Hydro's Total Sources of Supply includes generation, net exchange, gas and transportation for thermal generation, and purchases; total and supply breakdown data were provided by BC Hydro. Sources and notes on the data for the U.S. peer panel are described below by [column]:

[B]: Some utilities have a service territory that spans more than one state. In such instances, the state with the highest 2017 sales has been listed, based on data from 2017 EIA 861 Schedule 4, downloaded from Velocity Suite.

[C]: "E" indicates the utility only provides electric service; "E/G" indicates the utility provides both electric and gas service.

[D] – [E]: Data from 2017 EIA 861 Schedule 4, downloaded from Velocity Suite.

[F] – [G]: Data from 2017 EIA 860, downloaded from Velocity Suite.

[H] – [J]: Total Sources of Supply includes net generation, power purchases, and net power exchange. Data are from 2017 FERC Form 1, p. 401a, downloaded from Velocity Suite.

27. As indicated in the above, seven of the utilities are larger than BC Hydro in terms of delivered MWhs (or sales), while 16 are smaller. Similarly, in terms of the number of customers (column [E]), five utilities are larger than BC Hydro, with the remaining 18 smaller. There are several utilities in the panel that are located in either the Pacific

Northwest or the American West. As indicated earlier, also included are three utilities with significant hydro resources in their power mix.

28. Selecting a peer panel is, unfortunately, not a fully prescribed and cut and dry exercise. Instead, it involves a degree of professional judgement; equally reasonable alternate panels may also be specified. I tested the reasonableness of the above panel by comparing benchmarking results across such an alternate panel, in order to ensure that panel selection did not inadvertently provide aberrant results. The results for the alternate panel were acceptably close to the results for the selected panel, removing concerns of selection bias. Thus, overall and for the purposes of this study, I find that the selected peer panel provides a reasonable point of reference for assessing BC Hydro's relative NFOM cost performance.[17]

E. DATA

29. As indicated earlier, conducting a cost benchmarking study requires consistency of cost data. The FERC's USoA provides reasonable assurance that cost data reported by U.S. electric utilities follows similar categorizations of costs, and thus is widely used in cost benchmarking analyses.[18] The USoA categorizes O&M costs by major functional category; detailed supporting accounts, which sum to the major functional category total, are also provided. I conducted this benchmark study at the functional cost area level.

30. BC Hydro informed me that Canadian electric utilities do not consistently employ USoA reporting, which can make comparisons of costs—NFOM or otherwise—challenging, and requires information to be provided by individual utilities (in contrast to the publicly available cost data in the U.S.). BC Hydro indicated that their preferred focus for this cost benchmarking study was the costs of personnel, materials, and

[17] The alternate panel tested was composed of all vertically integrated U.S. investor owned electric utilities. It is possible to specify many other alternate panels (of course), and these may produce different results than that realized from the selected and alternate panel tested.

[18] However, utilities apply their own accounting practices and judgements in completing the FERC Form 1. I have found that, in some cases, reported cost levels may vary among utilities due to reporting practices, more so than because of differences in incurred costs. For example, not all utilities record all sales related costs in USoA accounts 911–913 and 916 (Sales).

external services (PMAES) as reported in its annual Consolidated Statement of Operations. BC Hydro advised me that these costs are equivalent to BC Hydro's net operating costs provided in its Revenue Requirements Application, after adjusting for its subsidiaries, Powerex and Powertech. BC Hydro also advised me that these costs are roughly consistent with the NFOM costs reported by U.S. utilities in annual FERC Form 1 filings. Discussion with BC Hydro indicated that PMAES costs needed to be adjusted in order to more accurately equate to the USoA based NFOM costs. As discussed earlier, BC Hydro re-organized its accounting data to convey its cost data in a USoA compatible format.

31. BC Hydro recommended that the USoA data used for the U.S. peer utilities be adjusted slightly—in accordance with the adjustments made to the BC Hydro data, as discussed above—to ensure that peer panel costs are more closely comparable to BC Hydro's NFOM costs. A summary of the USoA accounts used for each functional cost area is provided in the Figure 7 below.

Figure 7: FERC USoA Accounts by Cost Area

Cost Area	All FERC USoA Accounts in Cost Area	Excluded FERC USoA Accounts in Cost Area
Power Production	500-514, 517-525, 528-532, 535-557	501, 503, 504, 509, 518-522, 536, 547, 555
Transmission	560, 560.1-560.8, 562-569, 569.1-569.4, 570-573	
Regional Market	575.1-575.8, 576.1-576.5	575.6-575.8, 576.1-576.5
Distribution	580-598	
Customer Accounts	901-905	
Customer Service and Informational	907-910	
Sales	911-913, 916	
Administrative and General	920-929, 930.1, 930.2, 931, 935	927

32. BC Hydro recommended excluding USoA accounts relating mainly to fuel, steam, and water rentals involved in power production, as these are considered part of its cost of energy, rather than its operating costs. BC Hydro advised us to exclude expenses associated with market monitoring and operations incurred by some of the U.S. peers who participate in regional wholesale markets (such as MISO) and franchise

requirements (included under A&G)—costs in these areas are incurred by BC Hydro's subsidiary, Powerex, rather than BC Hydro itself.

33. BC Hydro reported its cost data in its annual reports and provided cost data in USoA compatible format on a fiscal year basis, which runs from April 1 through March 31 of each year. This is different than the timing used by U.S. utilities when filing annual FERC Form 1 reports, which cover calendar years (January 1 through December 31 of each year). Thus, BC Hydro NFOM cost data is not completely compatible with the U.S. utility peers, even if the cost accounts can be appropriately adjusted to be in line with USoA cost accounts. However, both data sets—BC Hydro and the U.S. utilities—reflect 12 months of cost experience, even if slightly out of sync. I addressed this by comparing BC Hydro's NFOM for fiscal year spanning 2013–2014 (ending March 31, 2014) with USoA NFOM data for calendar year 2013, and so on.

34. Finally, as indicated earlier, while BC Hydro has completed its accounting breakdown of functional costs for the years 2013–2015, it currently only has accounting records for NFOM at the total level (i.e., not broken down by functional cost area) for 2016 and 2017. For use in this study, I have developed a proxy for the functional-level cost totals for 2016 and 2017 by calculating each functional area's average share of total NFOM costs over the 2013–2015 and using those proportions to allocate the 2016 and 2017 total NFOM costs to each functional area. As shown in Figure 8 below, review of these proportions for 2013, 2014, and 2015 indicates that they have been quite stable on a year-to-year basis. However, it is possible that the actual functional costs for 2016 and 2017 would have differed had BC Hydro conducted its accounting at this level of detail.

Figure 8: Breakdown of Functional Cost Categories as Percentage of Total NFOM

Functional Cost Area	2013	2014	2015
Power Production	18%	18%	18%
Transmission	15%	16%	16%
Regional Market	0%	0%	0%
Distribution	18%	17%	18%
Customer Accounts	7%	7%	7%
Customer Service and Informational	0%	0%	1%
Sales	0%	0%	0%
Administrative and General	41%	41%	41%
Total	**100%**	**100%**	**100%**

Sources and Notes: Calculations by The Brattle Group, based on Uniform System of Accounts data provided by BC Hydro. Breakdown percentages may not sum to 100% due to rounding.

VI. BENCHMARKING RESULTS

35. A key part of the cost benchmarking methodology involves specifying metrics (e.g., cost per MWh). With this in place as discussed above, the comparative analysis mainly involves observing the position of BC Hydro each year with respect to the peer panel.

36. I provide graphic representations of the results of the cost benchmarking below. I show results for non-power production O&M in total and, in Appendix D, by underlying functional cost areas: transmission, distribution, the customer facing functions (customer accounts, customer service and information, and sales), and administrative and general. I also provide results for power production related O&M and for total NFOM (i.e., the sum of non-power production and power production related O&M expenses).

37. I include benchmarking results for the O&M costs per MWh (delivered MWhs for the non-power production O&M and generated MWhs for power production related O&M) and per customer.

38. Benchmarking results are presented in four quartiles. For cost benchmarking, this means that 25% of the utilities in the peer panel with lowest unit cost (for the cost metric under study) are included in the 1st quartile, the next 25% of utilities (through the median) are included in the 2nd quartile, etc. The peer panel for this study includes

23 utilities: 6 are included in each of the 1st and 4th quartiles, 5 utilities are included in the 2nd and 3rd quartiles, with one utility occupying the median position (the dividing line between the 2nd and 3rd quartiles). All results are presented in nominal Canadian dollars.[19]

A. NON-POWER PRODUCTION O&M COSTS

39. Non-Power Production NFOM costs include USoA accounts for Transmission expenses (which includes Transmission and Regional Market expenses), Distribution expenses, Customer-Facing expenses (which includes Customer Service, Customer Accounts and Information, and Sales), and Administrative and General expenses. Non-power production costs account for over 80% of BC Hydro's total NFOM.[20]

40. Figure 9 and Figure 10 provide a comparison of BC Hydro's Total Non-Power Production costs to its peers on a $ per delivered MWh and $ per customer basis.

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[19] The costs for the U.S. utilities were converted to Canadian dollars using yearly average currency exchange rates for the relevant period as retrieved from: https://www.irs.gov/individuals/international-taxpayers/yearly-average-currency-exchange-rates. As the 2018 exchange rate was not available at the time this analysis was completed, I use the 2017 exchange rate to convert 2018 U.S. dollars to Canadian dollars.

[20] In 2015, BC Hydro's Non-Power Production costs equaled

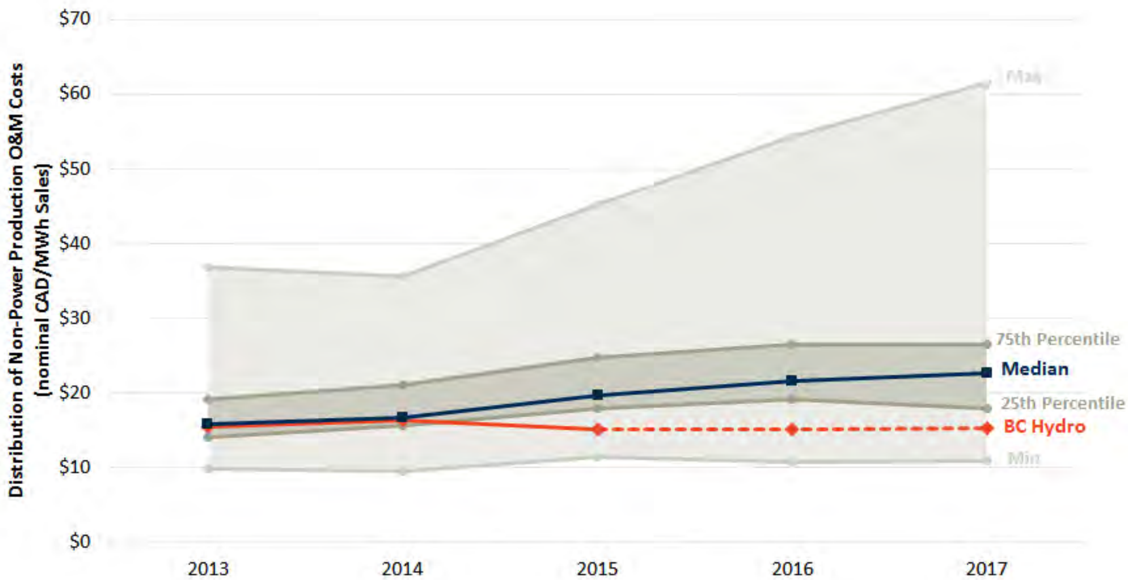
$868M = $165M (Transmission) + $186M (Distribution) + $81M (Customer-Facing) + $437M (Administrative and General).

BC Hydro's total NFOM in 2015 equals $1,062M. Therefore, the Non-Power Production cost share of total NFOM is equal to

82% = $868M / $1,062M.

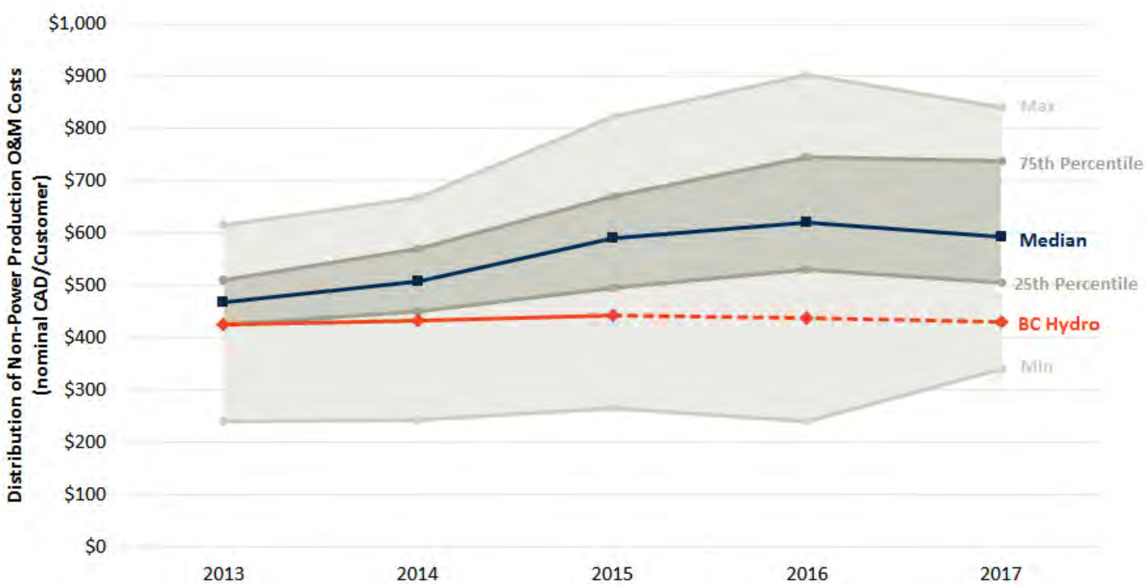
Non-Power Production expenses accounted for about 82% of total NFOM in 2013 and 2014 as well.

Figure 9: Non-Power Production NFOM ($ per Delivered MWh)



Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013-2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013-2017 FERC Form 1 data (pp. 321–323) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

Figure 10: Non-Power Production NFOM ($ per Customer)



Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (pp. 321–323) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

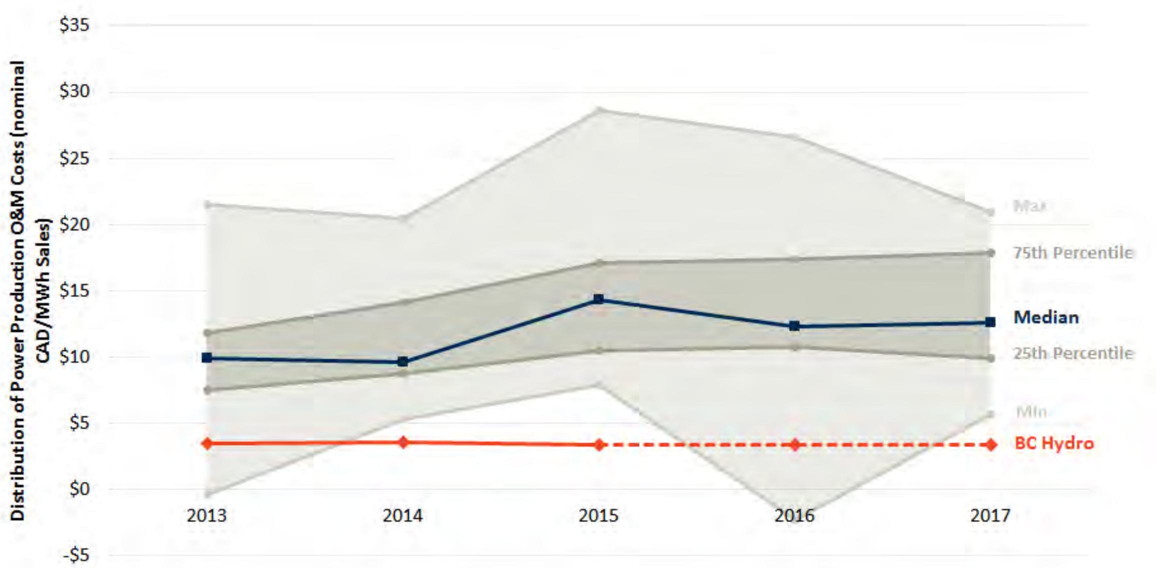
41. As shown in the figures above, BC Hydro's relative cost performance for the non-power production cost category is in the first or second quartile, depending on the year. Cost performance in this area appears to have improved in the latter years (2016 and 2017), but recall that these costs are estimated as a percentage of its recorded total

NFOM costs. A more detailed examination of the components of non-power production costs is provided in Appendix D to my report.

B. POWER PRODUCTION O&M COSTS

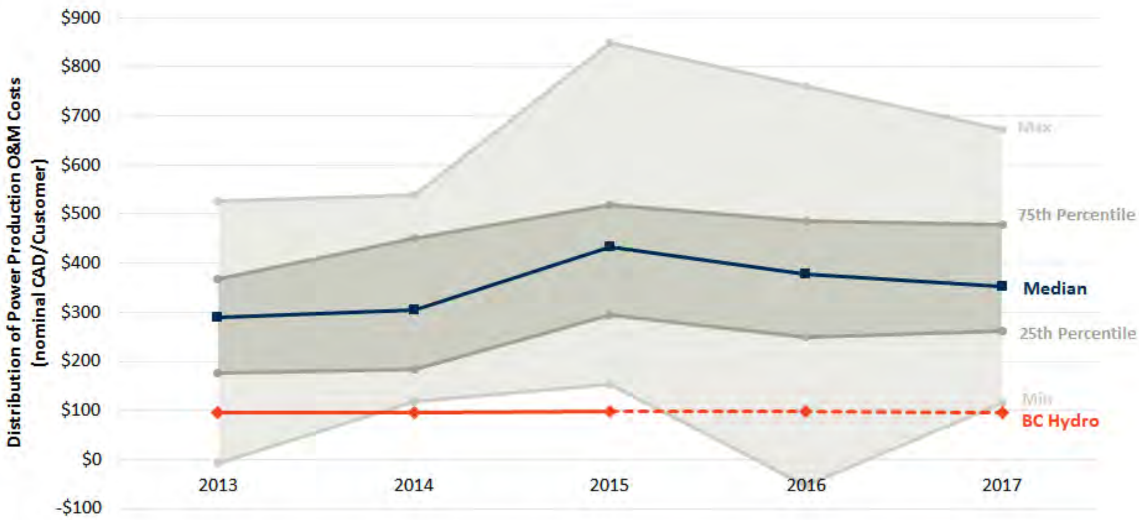
42. Power production O&M costs represent roughly 18% of BC Hydro's total NFOM costs. Cost benchmarking results for power production O&M excluding fuel costs (shown on a $ per generated MWh and $ per customer basis) are shown in Figure 11 and Figure 12, below.

Figure 11: Power Production O&M Cost Benchmarking ($ per Generated MWh)



Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (pp. 320–321 and 401a), downloaded from Velocity Suite.

Figure 12: Power Production O&M Cost Benchmarking ($ per Customer)



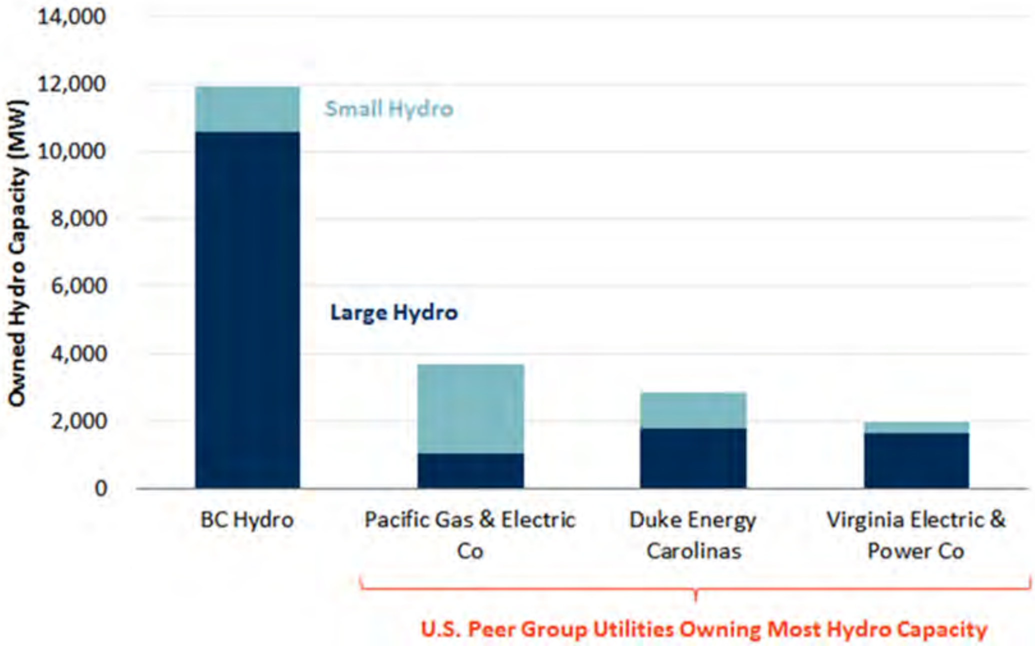
Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (pp. 320–321 and 401a), downloaded from Velocity Suite.

43. The figures show that BC Hydro's power production O&M are among the lowest of the peer group. However, the benchmarking results show that at least one utility (Nevada Power) shows zero and/or even negative O&M costs in some years. This is due to negative entries for USoA account 557 (Other expenses), most likely reflecting accounting adjustments and/or transfers.[21] Some other utilities in the panel have negative expenses under this account (although not large enough to offset the other positive costs), although BC Hydro does not. I elected not to exclude or make other adjustments to the panel or data, so as not to introduce selection bias.

44. BC Hydro's relative cost performance regarding power production O&M is likely explained by the high percentage of hydro facilities in its overall power production mix. Hydro facilities likely have lower O&M costs than do the non-hydro facilities that make up the majority of the power production facilities that are owned and/or operated by the other utilities included in the peer panel. Furthermore, as illustrated in Figure 13 below, BC Hydro has more large scale hydro than the other utilities in the panel. Smaller scale hydro facilities do not enjoy the same economies of scale as do larger scale units.

[21] Similarly, one peer group member incurs negative Transmission NFOM costs in some years; this is discussed in additional detail in Appendix D.

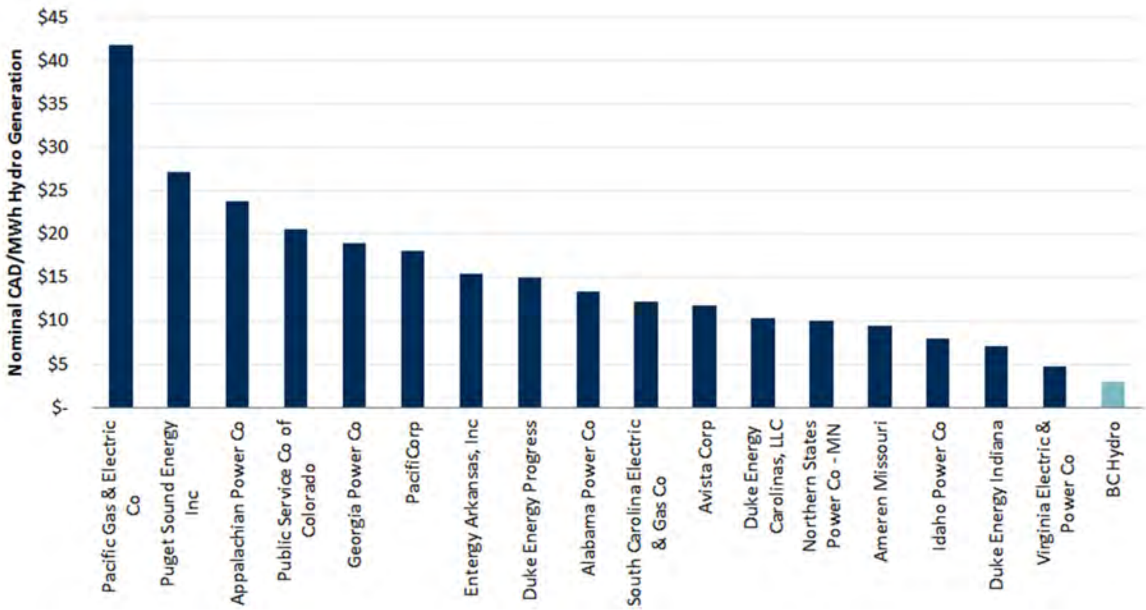
Figure 13: Hydro Generating Capacity by Facility Size, Selected Utilities



Sources and Notes: Data from EIA 860, downloaded from Velocity Suite. Hydro includes both conventional hydro generation and pumped storage. For the purposes of this chart, Large Hydro is defined as any hydro facility larger than 400 MW.

45. The volume and scale of BC Hydro's hydro-based generation appears to be a factor leading to its relatively low unit cost for power production O&M when compared to other utilities with hydro-based facilities. Figure 14 below shows the power production O&M costs (per MWh of hydro generation) for the hydroelectric plants owned and/or operated by 17 of the utilities included in the peer panel. BC Hydro's unit costs are the lowest, especially when compared with PG&E, whose mix of hydro resources includes a larger percentage of smaller scale resources than does that of BC Hydro.

Figure 14: 2015 Hydroelectric Power Production O&M
($ per MWh of Hydro Generation)



Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2015 USoA data and the 2015/16 Annual Report provided by BC Hydro. Values for the U.S. peer panel are based on 2016 FERC Form 1 data (pp. 320–321 and 401a), downloaded from Velocity Suite.

C. TOTAL O&M COSTS

46. I benchmarked BC Hydro's total NFOM on a $ per delivered MWh basis, with total NFOM defined as the sum of the individual functional cost areas that were benchmarked above. Figure 15 below shows BC Hydro's total NFOM costs for 2013 through 2017 as well as those costs on a per delivered MWh and per customer basis.

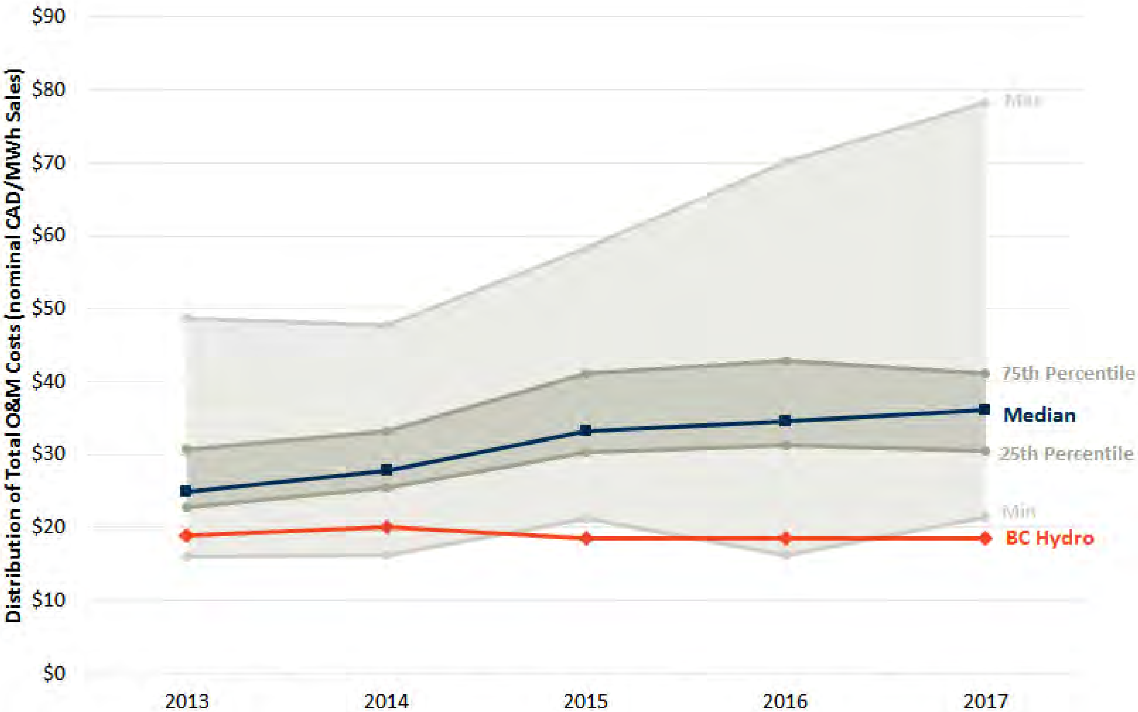
Figure 15: BC Hydro Total NFOM O&M Cost Metrics

Year	Total NFOM ($ millions)	Total Sales (GWh)	Total Customers	$ per Delivered MWh	$ per Customer
2013	$1,001	53,018	1,914,549	$18.88	$522.74
2014	$1,022	51,213	1,935,068	$19.96	$528.15
2015	$1,062	57,300	1,960,555	$18.54	$541.84
2016	$1,067	57,652	1,987,963	$18.51	$536.78
2017	$1,061	57,173	2,018,044	$18.55	$525.62

Sources: Calculations by The Brattle Group, based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro.

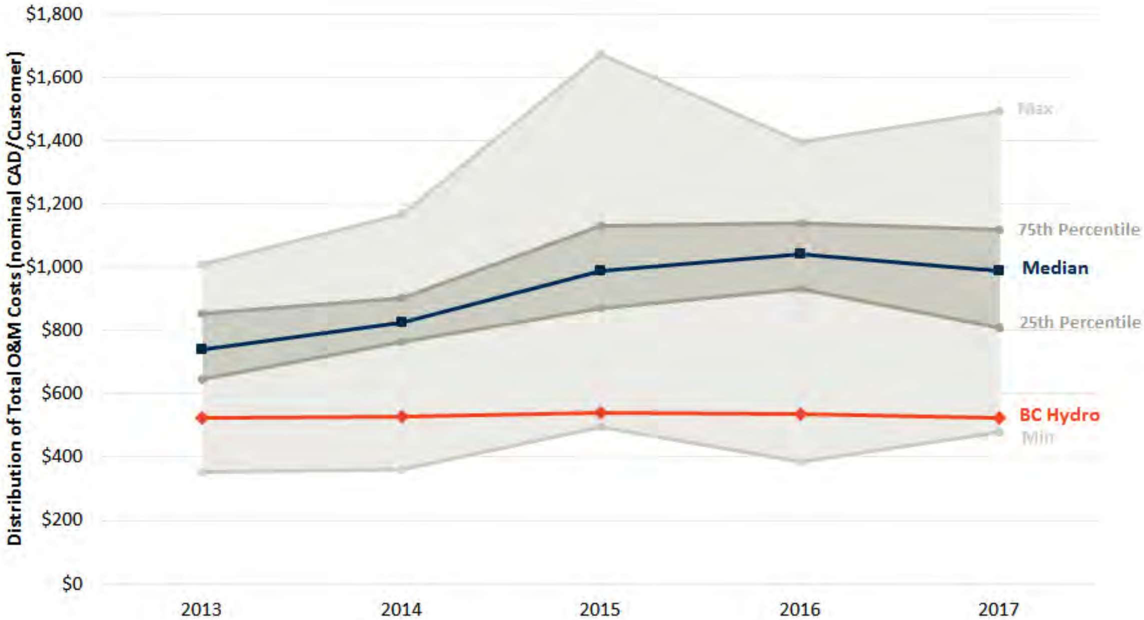
47. Figure 16 and Figure 17 show BC Hydro's total NFOM costs per delivered MWh and per customer in relation to comparable costs for the U.S. utilities included in the peer panel.

Figure 16: Total Non-Fuel O&M Costs ($ per Delivered MWh)



Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (pp. 320–323) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

Figure 17: Total Non-Fuel O&M Costs ($ per Customer)



Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2017 total NFOM data and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (pp. 320–323) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

48. As indicated in the figures, BC Hydro's total NFOM is among the lowest of the utilities in the peer panel for all of the years under study. However, this measure appears to be less informative than are the separated benchmarking results for non-power production NFOM and power production NFOM shown earlier in this report. This is primarily due to BC Hydro's unique position with respect to comparable power production NFOM, which has a strong influence on the total NFOM metrics.

VII. CONCLUSIONS

49. Conclusions with respect to cost benchmarking studies need to be accompanied by appropriate caveats concerning data and peers. That is, benchmarking results depend upon consistent data that accurately convey information about the cost areas under study. Cost benchmarking studies can almost always be improved upon with added levels of depth and investigation. "Peeling back the onion" is particularly important when benchmarking is undertaken for purposes of process improvement. I find that the level of depth included in the subject study is appropriate for assessing general NFOM unit cost comparisons.

50. I used standard metrics for this cost benchmarking analysis: costs per MWh and costs per customer. I have used these metrics in prior studies and have observed that they are routinely used in cost benchmarking studies. Other metrics may be applied in more focused or detailed analysis (e.g., the cost of tree trimming per distribution system mile); however this depth of benchmarking analysis typically requires additional and non-publicly available information, and was beyond the scope of my assignment.

51. The utilities used as points of comparison should represent a reasonable field of peers, with the important understanding that there will be few cases in which utilities are fully similarly situated. I used a relatively simple screening process in selecting a peer panel for this study in order to avoid "cherry picking," or deliberate selection bias. Peer panels can usually be improved upon with deeper analysis of candidate utilities and their related ecosystems and circumstances. For the purposes of this study, I find the peer panel appropriately representative of peer utilities in the U.S.[22]

52. I find that the USoA provides a reliable data set to represent the costs of U.S. utility O&M costs and, accordingly, used this format as the basis to conduct the subject cost benchmarking analysis. I noted earlier that these data are not perfect representations of costs (e.g., negative accounting entries, likely reflecting transfers and/or accounting adjustments). However, overall, I find that it is appropriate to base this cost benchmarking study on these data. I relied on BC Hydro to organize their accounting data in this USoA format.

53. Overall, in a "bottom line" sense, the cost benchmarking analysis indicates that BC Hydro's non-fuel operations and maintenance expenses, which cover utility, back office, and corporate operations (but excludes the costs of fuel and purchased power, depreciation, amortization, finance charges, and taxes), are comparatively lower than peer utilities, and in many cases fall in the first quartile, a sought-after position (from a cost perspective, assuming that the utility provides sufficient levels of service). Much of this strong showing is due to BC Hydro's strong unit cost performance in power production NFOM, in which BC Hydro is a 1st quartile performer. These results are

[22] Additional analysis can be brought to bear, including econometric analysis, to more fully explore peer panel options. Such analysis was outside of the scope of this study.

likely driven, at least in part, by differences in the generating fleet of BC Hydro, which is heavily focused on large-scale hydroelectric capacity, and those of the peer group utilities, which generally feature significant amounts of thermal capacity. Those peer utilities that do own hydroelectric capacity own fewer plants, and those plants are generally smaller-scale than the hydroelectric capacity owned by BC Hydro.

54. Excluding power production from NFOM provides a meaningful indicator for BC Hydro's comparative cost performance. This (total) non-power production NFOM metric includes transmission, distribution, customer-facing, and administrative and general expenses, which (as shown in Figure 1) accounts for over 80% of BC Hydro's total NFOM. BC Hydro was in the 2nd quartile of unit cost performance for this metric in the early years of this study (2013) and improved into the 1st quartile by 2015, mainly due to improvements in its cost performance in transmission and distribution.[23]

55. BC Hydro's performance with respect to NFOM costs in Transmission, Distribution, and Administrative and General accounts compares favorably with the rest of the peer group. In these measures, BC Hydro is in the first or second quartile or at the median, depending on the metric, and has generally improved its relative cost performance over the last five years.

56. BC Hydro's relative cost performance with respect to the Customer Facing functional area (made up of Customer Accounts, Customer Service and Informational Expenses, and Sales) is at or below the 1st quartile. BC Hydro has explained that its advances in these areas (e.g., its deployment of automated metering infrastructure (AMI) and paperless billing) might explain its relative cost efficiency.[24] However, review of the data set indicates that many utilities seem to treat Customer Facing costs in an aggregated fashion, or include these costs in other areas of operation. For example, some utilities (including BC Hydro) have not reported any costs in the Sales cost area, and have only minimal costs reported in the Customer Service and Informational

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[23] A causal analysis concerning the specific reasons behind the changes in BC Hydro's non-power production NFOM costs was beyond the scope of this study.

[24] Recall that this cost benchmarking analysis includes O&M costs only, not the capital costs associated with infrastructure such as AMI.

expenses cost area. For this reason, I draw limited conclusions with respect to BC Hydro's benchmarking performance with respect to the Customer Facing area, and rely more heavily upon the cost benchmarking results for non-power production O&M on a total basis.

Appendix A:

Curriculum Vitae of William P. Zarakas

William Zarakas is a Principal with The Brattle Group, an economics consulting firm, and an expert on economic and regulatory matters in the electricity, telecommunications and media industries. He heads Brattle's retail energy practice, and leads much of Brattle's work concerning regulatory and business models, cost and rate analysis, infrastructure deployments and grid modernization, and smart grid and utility platform issues. Mr. Zarakas has authored reports and articles on performance based regulation (PBR), "utility of the future" visions and implementation, and inter-modal competition in the retail electricity sector.

Mr. Zarakas also has a leadership role in Brattle's practice in telecommunications and media. He has provided expert reports and testimonies in a range of regulatory proceedings concerning competition issues in the telecommunications industry, forbearance from price regulation, and price and foreclosure issues potentially associated with mergers among telecom carriers and media companies. He has also developed models concerning the economics and financial feasibility of building-out broadband infrastructure, conducted valuations of a wide range of wireless spectrum bands and holdings, and examined the distribution of royalties and retransmission fees in the cable and satellite television industries.

He has also led special investigations on behalf of corporate boards of directors and audits of management practices and operational and financial performance on behalf of regulatory commissions.

Mr. Zarakas has provided testimony and expert reports before the Federal Communications Commission, the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Copyright Royalty Judges (Library of Congress), the U.S. Congress, state regulatory agencies, arbitration panels, foreign governments and courts of law.

He holds an M.A. in economics from New York University and a B.A., also in economics, from the State University of New York.

Utility Regulatory and Business Models. Analyzed, advised and/or testified on matters concerning regulatory frameworks, performance-based regulation (PBR) and utility business models, notably with respect to emerging competitive alternatives and network integration. Recent work includes:

- Analyzed implementation of New York's Reforming the Energy Vision by modeling the economics of the utility platform model, access pricing and financial impacts of retail competition on utility.
- Analyzed, advised and/or testified on matters concerning performance incentive mechanism (PIMs); e.g., analyses of: New York's "earnings adjustment mechanisms" on behalf of New York's six investor owned utilities) and performance measures and incentive structures on behalf of the Hawaiian Electric Companies.
- Surveyed and analyzed PBR frameworks and applications, including multi-year rate plans (MRPs), PIMs and other alternative regulatory mechanisms, including the U.K.'s "RIIO" model.

- Surveyed and analyzed regulatory approaches to setting electric distribution reliability standards around the world on behalf of the Australian Energy Market Commission (AEMC).
- Modeled multi-variate "utility of future" scenarios using system dynamic approach on behalf of utilities and industry groups.
- Advised Board of Directors of a major generation and transmission (G&T) cooperative and its member electric distribution cooperatives on matters concerning: asset valuations, risk management strategy, merger and acquisition options, and outlook for retail electric markets.

Infrastructure and Investment Analysis. Analyzed and testified on matters concerning infrastructure economics and financial feasibility. Work includes:

- Led benefit-cost and economic "break-even" analysis of utility system reliability and resilience investment using a value of lost load (VOLL) methodology on behalf of Public Service Electric & Gas Company (PSE&G).
- Developed cost and revenue models to estimate costs, feasibility and customer rates associated with deploying wireless broadband to rural areas on behalf of GCI Communications.
- Conducted financial feasibility analysis concerning deployment of a broadband communications network for an Asian electric utility.
- Analyzed economics and financial feasibility of providing (wholesale) transport and (retail) broadband services for multiple U.S. electric utilities.
- Led comprehensive modeling concerning costs and rates for unbundled network elements (UNEs), undertaken in fulfillment of requirements associated with the Telecommunications Act of 1996, using the Total Element Long Run Incremental Cost (TELRIC) methodology.

Due Diligence, Valuation and Management Audits. Work includes:

- Due diligence of northwestern U.S. electric and gas utility on behalf of buyer; analysis included comprehensive sales, revenue, and operating and capital cost modeling and scenarios.
- Led numerous analyses of the values of wireless spectrum in the U.S., Canada, the Middle East and North Africa (MENA), and other geographic markets. Scope of analyses included: PCS, AWS, 2.3-2.5 GHz, SMR, PLMR, IVDS, MSS and Big Leo spectrum bands, among others, for purposes of planning, transactional analysis, regulatory proceedings, domestic and international arbitration, and commercial litigation.
- Led strategic organizational options analysis for the Board of Trustees of the Long Island Power Authority (LIPA).
- Led special investigations; e.g., economic analysis of "swap" transaction for the Special Committee of the Board of Directors of Global Crossing.
- Led management and/or regulatory audits of utilities and telecommunications carriers on behalf of state regulatory commissions Alabama, Kentucky, Maryland, New York and Pennsylvania.

Competition and Antitrust. Recent work includes:

- Analyzed prospective merger savings and divestiture losses for electric and gas utilities in merger applications before the U.S. Securities and Exchange Commission (SEC).
- Analyzed effectiveness of retail competition in U.S. electricity markets.

- Examined market structure and degree of competition in U.S. retail telecom markets, with regard to Petitions for FCC to forbear from price regulating resale services and UNEs.
- Conducted merger simulation and horizontal and vertical foreclosure analyses for telecom and media mergers; e.g., Comcast-Time Warner Cable; AT&T-Time Warner; Sinclair-Tribune; and, Disney-Fox.
- Led comprehensive analysis of competition in U.S. markets for business data services (BDS, previously referred to as special access).
- Analyzed acquisition price premium in merger of cross-state gas and electric utilities.

Other Regulatory Analyses. Recent work includes:

- Led benchmarking studies of utility costs and regulatory practices.
- Analyzed markets for and costs of providing utility pole attachments.
- Calculated total factor productivity (TFP) and X factors in price regulation proceedings involving utilities before state regulatory commissions and incumbent telecommunications carriers before the FCC.
- Analyzed costs and value of retransmitted television programming in cable and satellite video markets on behalf of Music Claimants in proceedings involving distribution of royalty funds.
- Examined impact of regulatory fees and constraints on economic output in 22 countries in the Middle East and Africa for international mobile carrier.

Expert Testimony

Direct Testimony of William P. Zarakas On Behalf of Public Service Company of Oklahoma Before the Corporation Commission of the State of Oklahoma In the Appication of the Public Service Company of Oklahoma For an Adjustment To Its Rates and Charges and the Electric Service Rules, Regulations and Conditions of Service For Electric Service in the State of Oklahoma, Cause No. PUD 201800085 (September 21, 2018).

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Declaration (August 7, 2017) and Reply Declaration (August 29, 2017) of William P. Zarakas and Jeremy A. Verlinda Before the Federal Communications Commission In the Matter of Tribune Media Company (Transferor) and Sinclair Broadcast Group, Inc. (Transferee), Consolidated Applications for Consent to Transfer Control, MB Docket No. 17-179.

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Declaration of William P. Zarakas and Matthew Aharonian in the United States Court for the District of Columbia Circuit United States Telecom Association, Petitioner, v. Federal Communications Commission and the United States of America, Respondents, Case No. 15-1063 (and consolidated cases) (May 22, 2015).

Declarations Before the Federal Communications Commission In the Matter of Application of Comcast Corporation, General Electric Company and NBC Universal, Inc. for Comcast to Assign or Transfer Control of Licenses, Federal Communications Commission, MB Docket No. 10-56. Analysis of the FCC's Vertical Foreclosure and Nash Bargaining Models Applied To The Proposed Comcast-Time Warner Cable Transaction (December 21, 2014) and Supplemental Declaration: Analysis of the FCC's Vertical Foreclosure and Nash Bargaining Models Applied To The Proposed Comcast-Time Warner Cable Transaction (March 5, 2015).

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Before the New Mexico Public Regulatory Commission, In The Matter Of The Application of TECO Energy, Inc., New Mexico Gas Company, Inc. and Continental Energy Systems, LLC, For Approval of TECO Energy Inc.'s Acquisition of New Mexico Gas Intermediate, Inc. and For All Other Approvals and Authorizations Required To Consummate and Implement The Acquisition, Utility Case No. 13-00231-UT, On Behalf of TECO Energy, Inc., New Mexico Gas Company, Inc. and Continental Energy Systems, LLC, Joint Applicants (March 2014).

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"Review and Analysis of Service Quality Plan Structure In The Massachusetts Department of Public Utilities Investigation Regarding Service Quality Guidelines For Electric Distribution Companies and Local Gas Distribution Companies." Philip Q Hanser, David E. M. Sappington and William P. Zarakas, Massachusetts D.P.U. 12-120 (March 2013).

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Expert report in MCI WorldCom Network Services, Inc. v. MasTec, Inc. Before the United States District Court Southern District of Florida, Case No. 01-2059-CIV-GOLD (May 2002).

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"Analysis Of The Economic Impact Of A Divestiture Of The Gas Operations Of Rochester Gas And Electric Corporation" Before the U.S. Securities and Exchange Commission included in Form U-1 Application/ Declaration Under The Public Utility Holding Company Act of 1935 in the combination of Energy East Corporation with RGS Energy Group, Inc. (June 20, 2001) in Exhibit J-1 (May 15, 2001).

"Analysis Of The Economic Impact Of A Divestiture Of The Gas Operations Of Sierra Pacific Resources" Before the U.S. Securities and Exchange Commission included in Form U-1 Application/ Declaration Under The Public Utility Holding Company Act of 1935 in the acquisition by Sierra Pacific Resources of Portland General Electric Company, 2000 in Exhibit H-1 (January 31, 2000).

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Diraect (July 11, 1997) and Rebuttal (September 5, 1997) Panel Testimony of William P. Zarakas and D. Daonne Caldwell Before the Louisiana Public Service Commission In Re: Review of Consideration of BellSouth Telecommunications, Inc.'s TSLRIC and LRIC Cost Studies to Determine Cost of Interconnection Services and Unbundled Network Components, to Establish Reasonable, Non-Discriminatory, Cost-Based Tariff Rates, Docket Nos. U-22022/22093.

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Direct and Rebuttal Testimony Before the Florida Public Service Commission on Behalf of Southern Bell Telephone & Telegraph Company, Docket No. 920260-TL (December 10, 1993).

Direct and Rebuttal Testimony Before the Tennessee Public Service Commission on behalf of South Central Bell, Docket Nos. 92-13527 and 93-00311 (March 22 and March 29, 1993).

Papers,Publications and Presentations

Washington D.C. Performance Based Regulation Workshop, presented by William Zarakas, Sanem Sergici and Pearl Donohoo-Vallett, September 19, 2018.

Hawaii Public Utilities Commission Performance Based Regulation Workshop, PBR Tools and Experience Panel, "The Intersection of Utility Platforms and PBR," William Zarakas, Honolulu, HI, July 23-24, 2018.

"A New Face for PBR: Aligning Incentives in the Electric Utility Ecosystem" by William Zarakas, *Public Utilties Fortnightly*, December 2017.

"Two-sided Markets and the Utility of the Future: How Services and Transactions Can Shape the Utility Platform," by William P. Zarakas, *The Electricity Journal*, Volume 30 (2017) 43-46.

Performance Based Regulation: Plans Goals, Incentives and Alignment, by William Zarakas, Toby Brown, Léa Grausz, Heidi Bishop and Henna Trewn, prepared for DTE Energy, December 6, 2017.

PBR: Applications and Future, presented by William Zarakas to the Michigan PSC PBR Collaborative, Lansing, Michigan, November 8, 2017.

"DER Incentive Mechanisms as a Bridge to the Utility of the Future," by William P. Zarakas, Frank C. Graves and Heidi Bishop, presented at SNL Knowledge Center's Energy Utility Regulation Conference: Strategies for Profit and Reliability, December 14, 2016.

"Electric Utility Services and Evolving Platforms in the Mid-Atlantic Region," by William Zarakas, presented at the Mid-Atlantic Conference of Regulatory Utilities Commissioners (MACRUC) 20th Annual Education Conference, Williamsburg, VA, June 23, 2015.

"Growth Prospects and Shifting Electric Utility Business Models: Retail, Wholesale and Telecom Markets," by William P. Zarakas, *The Electricity Journal*, Volume 28, Issue 5, June 2015.

"Do We Need a New Way to Regulate Electric Utilities?," by William P. Zarakas, presented at the Energy Bar Association 2015 Annual Meeting, Washington, DC, May 6, 2015.

"Investing In Electric Reliability and Resiliency," by William P. Zarakas, presented at the NARUC 2014 Summer Meeting - Joint Electricity and Critical Infrastructure Committees, Dallas, TX, July 15, 2014.

"Utility Investments in Resiliency: Balancing Benefits with Cost in an Uncertain Environment," by William P. Zarakas, Sanem Sergici, Heidi Bishop, Jake Zahniser-Word and Peter S. Fox-Penner, *The Electricity Journal,* Volume 27, Issue 5, June 2014.

"Infrastructure and Competition in the Electric Delivery System," by William P. Zarakas, *The Electricity Journal*, Volume 26, Issue 7, September 2013.

“Low Voltage Resiliency Insurance, Portable small-scale generators could keep vital services on line during a major power outages,” by William Zarakas, Frank Graves, and Sanem Sergici, *Public Utilities Fortnightly* September 2013.

"Finding the Balance Between Reliability and Cost: How Much Risk Should Consumers Bear?," by William P. Zarakas and Johannes P. Pfeifenberger, presented at the Western Conference of Public Service Commissioners, Santa Fe, NM, June 3, 2013

"The Utility of the Future: Distributed or Not?," by William P. Zarakas, presented at Advanced Energy 2013, New York, NY, April 30, 2013

"Rates, Reliability, and Region," by William P. Zarakas, Philip Q Hanser, and Kent Diep, *Public Utilities Fortnightly*, January 2013

"Approaches to Setting Electric Distribution Reliability Standards and Outcomes," by Serena Hesmondhalgh, William P. Zarakas, and Toby Brown, The Brattle Group, Inc., January 2012

“Analysis of Strategic Organizational Options for the Long Island Power Authority,” by William P. Zarakas, Frank C. Graves, and Michael J. Beck, prepared for the Board of Trustees, Long Island Power Authority, October 2011.

“Measuring Concentration In Radio Spectrum License Holdings,” by Coleman Bazelon and William Zarakas, presented at the Telecommunications Policy Research Conference (TPRC), George Mason University, September 26, 2009.

“Structural Simulation of Facility Sharing: Unbundling Policies and Investment Strategy in Local Exchange Markets,” White Paper, July 2005 (with Glenn A. Woroch, Lisa V. Wood, Daniel L. McFadden, Nauman Ilias, and Paul C. Liu).

“Betting Against The Odds? Why broadband over power lines (BPL) can’t stand alone as a high-speed Internet offering.” Public Utilities Fortnightly, April 2005, pp. 41-45 (with Kenneth J. Martinian).

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“Wholesale Pricing and Local Exchange Competition”, Info, Volume 6, Number 5, 2004, pp. 318-325 (with Lisa V. Wood and David E. M. Sappington).

“Regulatory Performance Measurement Plans and the Development of Competitive Local Exchange Telecommunications Markets”, Working Paper, November 2003 (with David E. M. Sappington, Lisa V. Wood and Glenn A. Woroch).

“FCC Pole Attachment Rates: Rebutting Some of the Presumptions,” presented to utility regulators, March 2003 (with Lisa V. Wood).

"The Concurrent Exchange of Fiber Optic Capacity and Services Between Global Crossing and its Carrier Customers," prepared for Special Committee on Accounting Matters of the Board of Directors of Global Crossing Ltd., January 2003.

Appendix B:

Letter of Instruction

FASKEN

Fasken Martineau DuMoulin LLP
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December 3, 2018
File No.: 301539.00025/15275

Via Email
Privileged and Confidential

The Brattle Group, Inc.
One Beacon Street Suite 2600
Boston, MA 02108, US

Attention: Bill Zarakas and Sanem Sergici

Dear Sirs/Mesdames

Re: British Columbia Hydro & Power Authority ("BC Hydro") Application to the British Columbia Utilities Commission ("Commission") for Approval of Revenue Requirements and Rates for Fiscal 2020 (the "Regulatory Proceeding")

As you are aware, we act on behalf of BC Hydro in the above referenced Regulatory Proceeding. This letter of instruction confirms your engagement for the provision of an independent expert report to be introduced into evidence in that Regulatory Proceeding. It outlines the issues to be addressed and provides some general guidance as to the format of your report.

Apart from our instructions below as to the issues to be addressed and the format of your report, the contents of your report are entirely for you in the exercise of your independent professional judgment. We are retaining you to provide independent expert evidence for the above captioned Regulatory Proceeding, not as an advocate for our client. The integrity of your conclusions is dependent upon your objectivity.

<u>Matters on Which Your Opinion is Requested</u>

We request that your report set out your independent objective opinion with respect to the following questions:

1. What would be the appropriate metrics for benchmarking BC Hydro's overall base operating costs and why?

2. What would be an appropriate representative peer group for benchmarking BC Hydro's base operating costs and why?

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3. What data is available from the selected peer group on the selected metrics over the last three or five years?

4. What methodology should be used to normalize the data and benchmark BC Hydro's base operating costs against its peer group?

5. What are the results of this normalization and benchmarking analysis?

In order to facilitate your analysis and the preparation of your report, BC Hydro is making available information, e.g., on its costs and operations, that you request. You can assume, for the purposes of your analysis, that information provided by BC Hydro is accurate.

Overview of the Structure of Your Report

We request that your independent expert report be set out consistently with the following structure.

A. Introduction and Summary of Opinion

Your introduction should

- reference the nature of your engagement as an independent expert as per this letter,
- identify the questions posed to you, and
- set forth, in a summary fashion, your independent objective opinions on each question.

B. Qualifications

Please state your professional qualifications, technical education, training and experience. Explain how your expertise relates to the subject matter of your opinions. Your detailed *curricula vitae* should be attached as an appendix.

C. Duty of Independence

We confirm that you have a duty to assist the Commission and are not to be an advocate for any party ("Duty of Independence"). In this section of your report, we require that you certify the following:

- You are aware of your Duty of Independence,
- You have prepared your report in accordance with the Duty of Independence, and
- If called to give oral or written testimony, you will give that testimony in conformity with the Duty of Independence.

D. Issues

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This section should set out the issues as posed in this letter.

E. Discussion

Under this heading, you should set out in full your independent objective opinions in the same order that the issues are presented. You should provide the reasons for your opinions including reference to pertinent facts or assumptions, any research you conducted that led you to form the opinion, and any applicable technical or other documents, standards, guidelines, etc.

F. Conclusion

You may provide a conclusion if you wish.

Appendices

Please include this letter, and the *curricula vitae* of those people responsible for the content of your report, as appendices to your report. If additional instructions are required, then supplementary letters of instruction from us should also be attached to your report. You may attach other documents or schedules that elaborate on, or are integral to your analysis.

In conclusion, if you have any questions with respect to the nature and scope of your engagement, please contact the writer at your soonest convenience.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[original signed by]

Matthew T. Ghikas
Personal Law Corporation

MTG/gvm

cc Chris Sandve
Manager, Rates and Finance
BC Hydro

Appendix C:

Determination of U.S. Peer Panel for BC Hydro

1. Tables C1 through C4 below show the full list of U.S. Investor Owned Utilities that were screened to determine BC Hydro's peer panel. Sources and notes for all four tables are included on the last page of this attachment.

2. Utilities in navy blue are the peer group that was determined from the initial benchmarking screen—these utilities are vertically integrated and had total sales greater than 20 TWh in 2017. I also include three utilities that do not fit one of the two criteria above but own a generation fleet that contains a significant percentage of hydro. These utilities are shown in light blue in the tables below. Avista Corp and Idaho Power Co have sales that are somewhat lower than 20 TWh (9 TWh and 15 TWh, respectively), but are vertically integrated, with hydro making up around 50% of total owned capacity. Pacific Gas & Electric Co is not vertically integrated, but has total sales of 62 TWh (comparable to BC Hydro's total sales of 57 TWh), with hydro again making up around 50% of total owned capacity.

Table C1: Peer Panel Screening – 1

		Initial Screening Characteristics		
Utility	State	Vertically Integrated	Total Sales *TWh*	Owned Hydro Capacity *% Total*
Alabama Power Co	AL	1	54	14%
Alaska Electric Light & Power Co	AK	1	0	18%
ALLETE Inc	MN	1	9	6%
Ameren Illinois	IL	0	8	0%
Ameren Missouri	MO	1	32	7%
Appalachian Power Co	VA	1	27	13%
Arizona Public Service Co	AZ	1	28	0%
Atlantic City Electric Co	NJ	0	4	n/a
Avista Corp	WA	1	9	54%
Black Hills Colorado Electric Utility Co LP	CO	1	2	0%
Black Hills Power Inc	SD	1	2	0%
Central Hudson Gas & Electric Corp	NY	0	3	53%
Central Maine Power Co	ME	0	4	1%
Cheyenne Light Fuel & Power Co	WY	1	2	0%
CLECO Power LLC	LA	1	8	0%
Cleveland Electric Illuminating Co (The)	OH	0	2	n/a
Commonwealth Edison Co	IL	0	26	n/a
Connecticut Light & Power Co (The)	CT	0	9	100%
Consolidated Edison Co of New York Inc	NY	0	19	0%
Consolidated Water Power Co	WI	1	1	100%
Consumers Energy Co	MI	0	33	17%
Dayton Power & Light Co (The)	OH	0	4	0%
Delmarva Power & Light Co	DE	0	6	n/a
DTE Electric Co	MI	0	42	9%
Duke Energy Carolinas, LLC	NC	1	77	13%
Duke Energy Florida, LLC	FL	1	38	0%
Duke Energy Indiana	IN	1	27	1%
Duke Energy Kentucky	KY	1	4	0%
Duke Energy Ohio	OH	0	4	n/a
Duke Energy Progress	NC	1	43	2%

Table C2: Peer Panel Screening – 2

Utility	State	Vertically Integrated	Total Sales *TWh*	Owned Hydro Capacity *% Total*
	Initial Screening Characteristics			
Duquesne Light Co	PA	0	4	n/a
El Paso Electric Co	TX	1	8	0%
Emera Maine	ME	0	1	0%
Empire District Electric Co (The)	MO	1	5	1%
Entergy Arkansas, Inc	AR	1	21	1%
Entergy Mississippi Inc	MS	1	13	0%
Entergy New Orleans Inc	LA	1	6	0%
Entergy Texas Inc	TX	0	18	0%
Fitchburg Gas & Electric Light Co	MA	0	0	n/a
Florida Power & Light Co	FL	1	109	0%
Georgia Power Co	GA	1	82	7%
Granite State Electric Co	NH	0	0	n/a
Green Mountain Power Corp	VT	1	4	29%
Gulf Power Co	FL	1	11	0%
Idaho Power Co	ID	1	15	47%
Indiana Michigan Power Co	IN	1	18	1%
Indianapolis Power & Light	IN	1	13	0%
Interstate Power & Light Co	IA	1	14	0%
Jersey Central Power & Light Co	NJ	0	10	99%
Kansas City Power & Light Co	MO	1	15	0%
Kansas Gas & Electric Co	KS	1	10	0%
KCP&L Greater Missouri Operations Co	MO	1	8	0%
Kentucky Power Co	KY	1	6	0%
Kentucky Utilities Co	KY	1	18	0%
Kingsport Power Co	TN	0	2	n/a
Lockhart Power Co	SC	1	0	59%
Louisville Gas & Electric Co	KY	1	12	3%
Madison Gas & Electric Co	WI	1	3	0%
Massachusetts Electric Co	MA	0	6	0%
MDU Resources Group Inc	ND	1	3	0%

Table C3: Peer Panel Screening – 3

	Initial Screening Characteristics			
Utility	State	Vertically Integrated	Total Sales *TWh*	Owned Hydro Capacity *% Total*
Metropolitan Edison Co	PA	0	4	n/a
MidAmerican Energy Co	IA	1	24	0%
Mississippi Power Co	MS	1	10	0%
Monongahela Power Co	WV	1	12	0%
Narragansett Electric Co	RI	0	4	n/a
Nevada Power Co	NV	1	21	0%
New York State Electric & Gas Corp	NY	0	7	79%
Niagara Mohawk Power Corp	NY	0	13	61%
Northern Indiana Public Service Co	IN	1	17	1%
Northern States Power Co - MN	MN	1	34	0%
Northern States Power Co (Wisconsin)	WI	1	7	32%
Northwestern Wisconsin Electric Co	WI	1	0	1%
NSTAR Co d/b/a Eversource Energy	MA	0	6	0%
Ohio Edison Co	OH	0	4	0%
Ohio Power Co	OH	0	11	n/a
Ohio Valley Electric Corp	OH	0	0	0%
Oklahoma Gas & Electric Co	OK	1	26	0%
Orange & Rockland Utilities Inc	NY	0	2	n/a
Otter Tail Power Co	MN	1	5	1%
Pacific Gas & Electric Co	CA	0	62	48%
PacifiCorp	UT	1	55	9%
PECO Energy Co	PA	0	11	n/a
Pennsylvania Electric Co	PA	0	4	n/a
Pennsylvania Power Co	PA	0	1	n/a
Portland General Electric Co	OR	0	18	12%
Potomac Edison Co (The)	WV	0	7	n/a
Potomac Electric Power Co	MD	0	8	n/a
PPL Electric Utilities Corp	PA	0	9	n/a
Public Service Co of Colorado	CO	1	29	6%
Public Service Co of New Hampshire	NH	1	3	0%

Table C4: Peer Panel Screening – 4

Utility	Initial Screening Characteristics State	 Vertically Integrated	 Total Sales *TWh*	 Owned Hydro Capacity *% Total*
Public Service Co of New Mexico	NM	1	9	0%
Public Service Co of Oklahoma	OK	1	18	0%
Public Service Electric & Gas Co	NJ	0	20	0%
Puget Sound Energy Inc	WA	1	21	7%
Rochester Gas & Electric Corp	NY	0	3	100%
Rockland Electric Co	NJ	0	1	n/a
San Diego Gas & Electric Co	CA	0	16	0%
Sierra Pacific Power Co	NV	1	9	1%
South Carolina Electric & Gas Co	SC	1	22	15%
Southern California Edison Co	CA	0	72	37%
Southern Indiana Gas & Electric Co	IN	1	5	0%
Southwestern Electric Power Co	TX	1	17	0%
Southwestern Public Service Co	TX	1	19	0%
Superior Water Light & Power Co	WI	0	1	n/a
Tampa Electric Co	FL	1	19	0%
Toledo Edison Co (The)	OH	0	1	0%
Tucson Electric Power Co	AZ	1	9	0%
United Illuminating Co (The)	CT	0	2	n/a
Unitil Energy Systems	NH	0	1	n/a
UNS Electric Inc	AZ	1	2	0%
Upper Peninsula Power Co	MI	0	1	39%
Virginia Electric & Power Co	VA	1	81	11%
West Penn Power Co	PA	0	7	n/a
Westar Energy Inc	KS	1	10	0%
Western Massachusetts Electric Co	MA	0	1	n/a
Wheeling Power Co	WV	0	4	n/a
Wisconsin Electric Power Co	WI	0	25	2%
Wisconsin Power & Light Co	WI	0	11	2%
Wisconsin Public Service Corp	WI	0	11	2%

Sources and Notes:

Utilities in this list are Investor Owned Utilities have 2017 Sales, Customer, and Generation data available; “n/a” (in light gray) indicates missing capacity data. Utility characteristics are reported for 2017.

For utilities that have a service territory that spans more than one state, the state with the highest 2017 sales has been listed, based on data from 2017 EIA 861 Schedule 4, downloaded from Velocity Suite. A utility is generally assumed to be vertically integrated if it is located in a state that has a regulated electricity market (based on information from Energywatch, available here: https://energywatch-inc.com/regulated-vs-deregulated-electricity-markets/), although Appalachian Power Co and Virginia Electric & Power Co were determined to be vertically integrated based on information reported on the utility websites. Total Sales is from 2017 EIA 861 Schedule 4, downloaded from Velocity Suite. Owned Hydro Capacity is calculated by The Brattle Group, based on data from 2017 EIA 860, downloaded from Velocity Suite.

Appendix D:

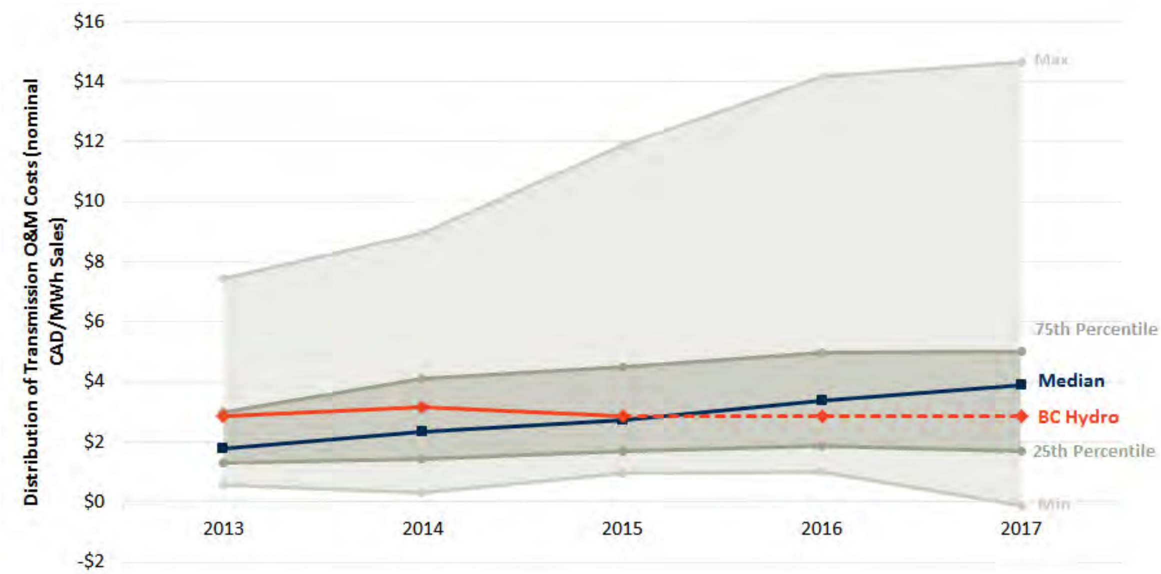
Detailed NFOM Cost Benchmarking for Non-Power Production Costs

1. This Appendix presents the benchmarking results for several more granular measures of NFOM, which together comprise the non-power production costs that are discussed in Section VI.A. of my report. The more granular measures presented here correspond to the functional categories used in USoA accounting.

A. Transmission O&M Costs

2. BC Hydro's cost performance with respect to Transmission O&M costs (which includes Transmission and Regional Market expenses) per delivered MWh and per customer are shown in Figures D1 and D2. Transmission O&M accounts for roughly 15% of BC Hydro's total NFOM costs. The O&M expenses that are included in the Transmission functional category include all of the O&M expenses in the USoA accounts for Transmission, as well as about half of the USoA accounts for Regional Market expenses.[1]

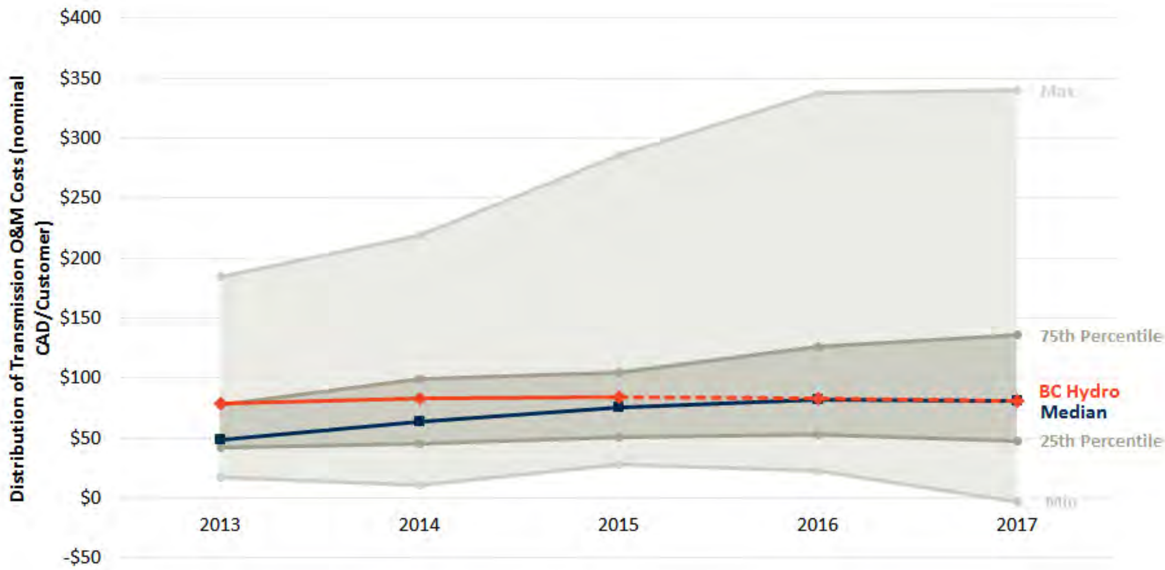
Figure D1: Transmission NFOM Benchmarking ($ per Delivered MWh)



Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (pp. 321–322) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

[1] The excluded accounts are Regional Market 575.6–575.8 and 576.1–576.5. These accounts include costs associated with market monitoring and compliance; less than half of the U.S. panel has incurred these costs. The remaining excluded accounts pertain to maintenance of regional market structures and equipment, but none of the peer group members has reported costs in these maintenance accounts.

Figure D2: Transmission NFOM Benchmarking ($ per Customer)



Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (p. 321–322) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

3. BC Hydro's Transmission O&M costs per delivered MWh declined over the course of the study term, starting out in the third quartile and dropping after 2015, to the second quartile on a per delivered MWh basis, and to the median on a per customer basis.

4. Inspection of the figures indicates that the transmission NFOM cost for one of the utility in the panel peer group (Virginia Electric Power Company, or VEPCo) is negative in 2017.[2] This is the result of a negative accounting in USoA account 566 (Misc. Transmission Expenses), and likely reflects accounting adjustments and/or transfers. Other utilities in the panel have reported such negative values in the data set. Excluding VEPCo and/or other negative accounting from the peer data set would place BC Hydro in a more preferential position in the benchmarking study. I have elected to use the data set without such adjustments in order to avoid selection bias. In effect, using the data set on an unadjusted basis provides a conservative indicator of BC Hydro's comparable cost position.[3]

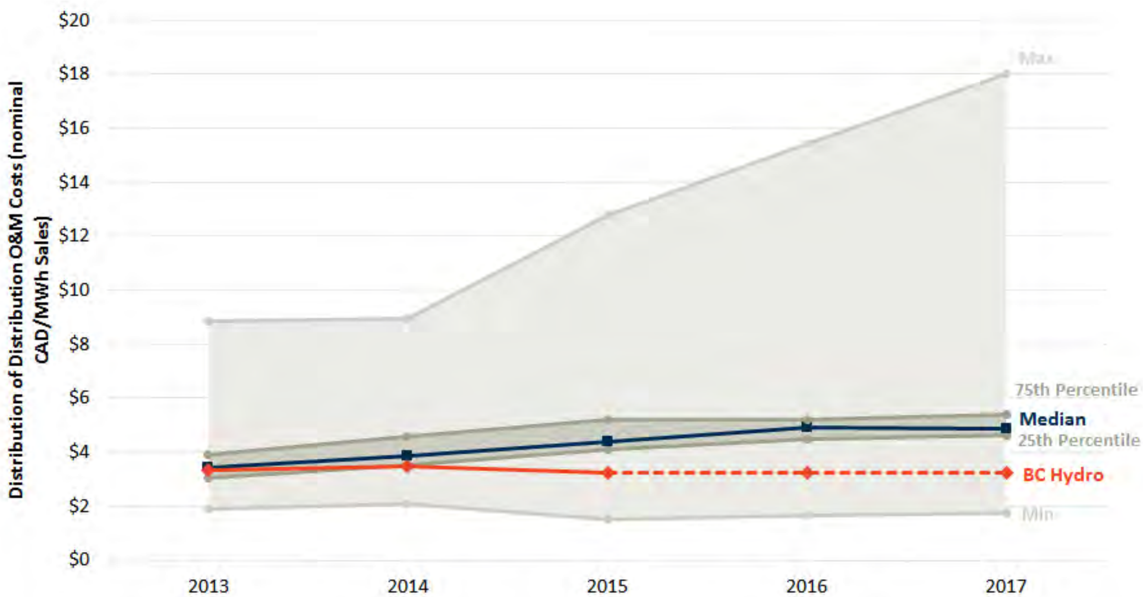
[2] Virginia Electric Power Company (VEPCo) is referred to as Dominion Energy or Dominion Virginia Power.

[3] Note that it is possible to exclude the affected utilities and/or data from benchmarking results without compromising the cost benchmarking study.

B. DISTRIBUTION O&M COSTS

5. Figures D3 and D4 show BC Hydro's Distribution NFOM costs on a per delivered MWh and per customer basis compared to the selected peer panel for 2013 to 2017. Distribution O&M accounts for roughly 17% of BC Hydro's total NFOM costs. The costs in this functional cost area include all of the O&M expense accounts included in the USoA for Distribution.[4]

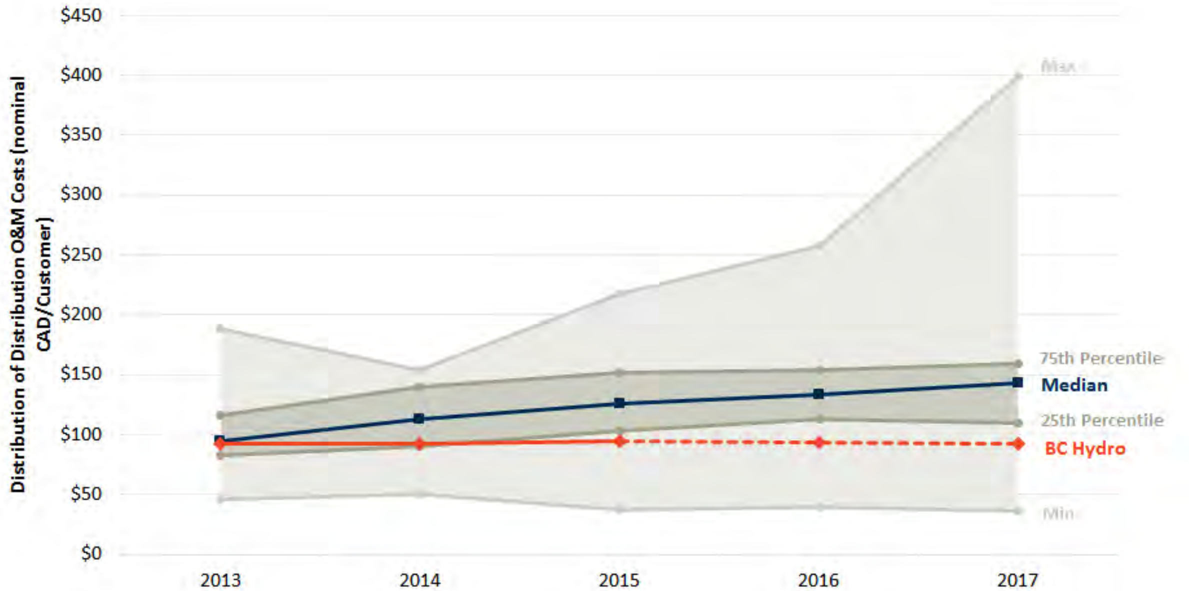
Figure D3: Distribution O&M Cost Benchmarking ($ per Delivered MWh)



Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (p. 322) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

4 These are made up of USoA accounts 580–598.

Figure D4: Distribution O&M Cost Benchmarking ($ per Customer)



Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (p. 322) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

6. As the figures indicates, BC Hydro's Distribution NFOM (on both a $ per delivered MWh $ per customer basis) are in the first and second quartile for the years under study, and were consistently in the first quartile after 2014.

C. CUSTOMER-FACING O&M COSTS

7. The O&M expenses that are included in the Customer-Facing functional category include all of the O&M expenses in the USoA accounts for Customer Accounts Expenses, Customer Service and Informational Expenses, and Sales Expenses.[5] These costs account for roughly 8% of BC Hydro's total NFOM costs.[6] Figures D5 and D6 show BC Hydro's Customer-Facing O&M costs compared to those of the selected U.S. peer panel for 2013 to 2017 on a $ per delivered MWh and $ per customer basis.

[5] These accounts are Customer Accounts 901-905; Customer Service and Informational 907–910; and Sales 911–913 and 916.

[6] In 2015, BC Hydro's Customer-Facing costs are equal to

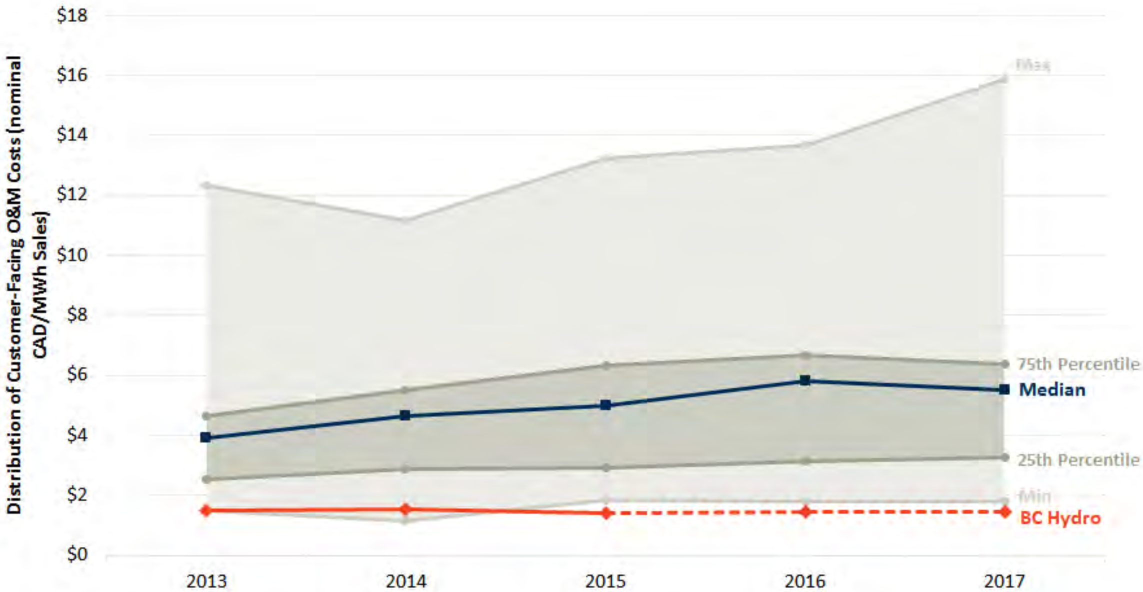
$81M = $75M (Customer Accounts) + $6M (Customer Service and Informational) + $0 (Sales).

BC Hydro's total NFOM in 2015 equals $1,062M. Therefore, the Customer-Facing cost share of total NFOM is equal to

8% = $81M / $1,062M.

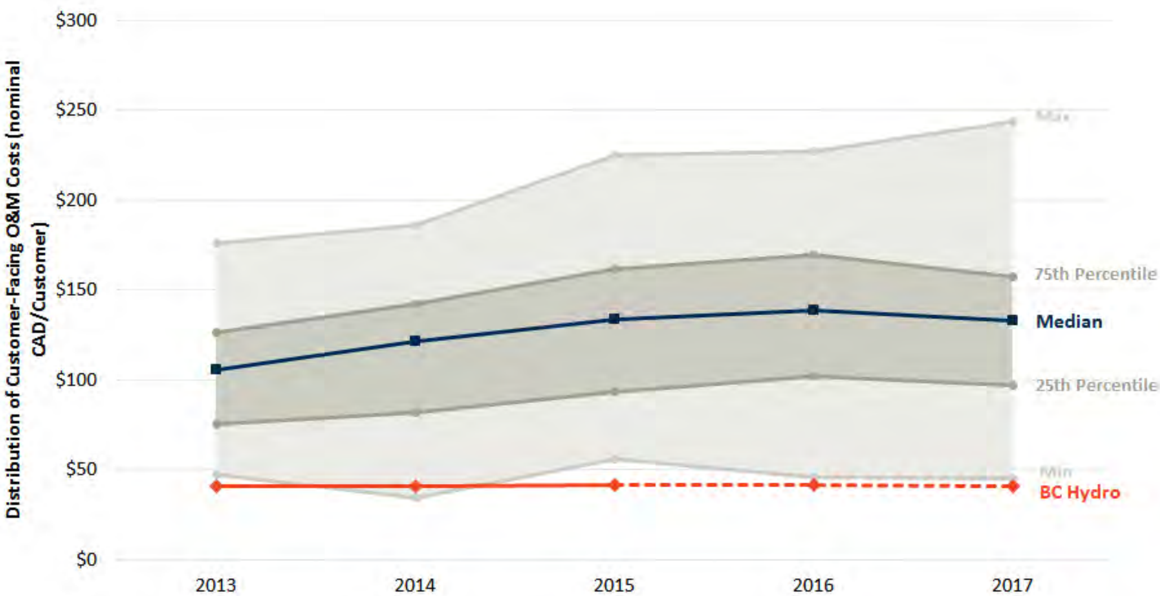
Customer-Facing expenses accounted for about 8% of total NFOM in 2013 and 2014 as well.

Figure D5: Customer-Facing O&M Cost Benchmarking ($ per Delivered MWh)



Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (pp. 322–323) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

Figure D6: Customer-Facing O&M Cost Benchmarking ($ per Customer)

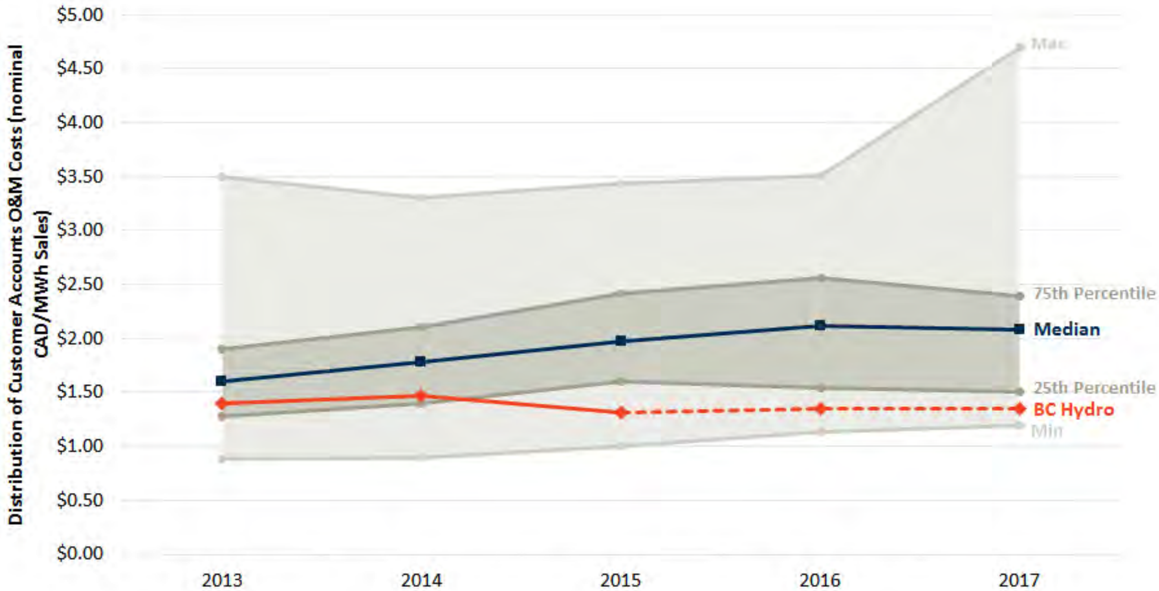


Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (pp. 322–323) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

8. The figures indicates that BC Hydro's Customer-Facing costs have consistently been either at or below the minimum of the peer group. I have found that utilities do not necessarily report these costs in a consistent manner. For example, it is common for some utilities to not record any costs in the Sales functional cost area. In order to account for these inconsistencies in accounting for Customer-Facing costs, I examined

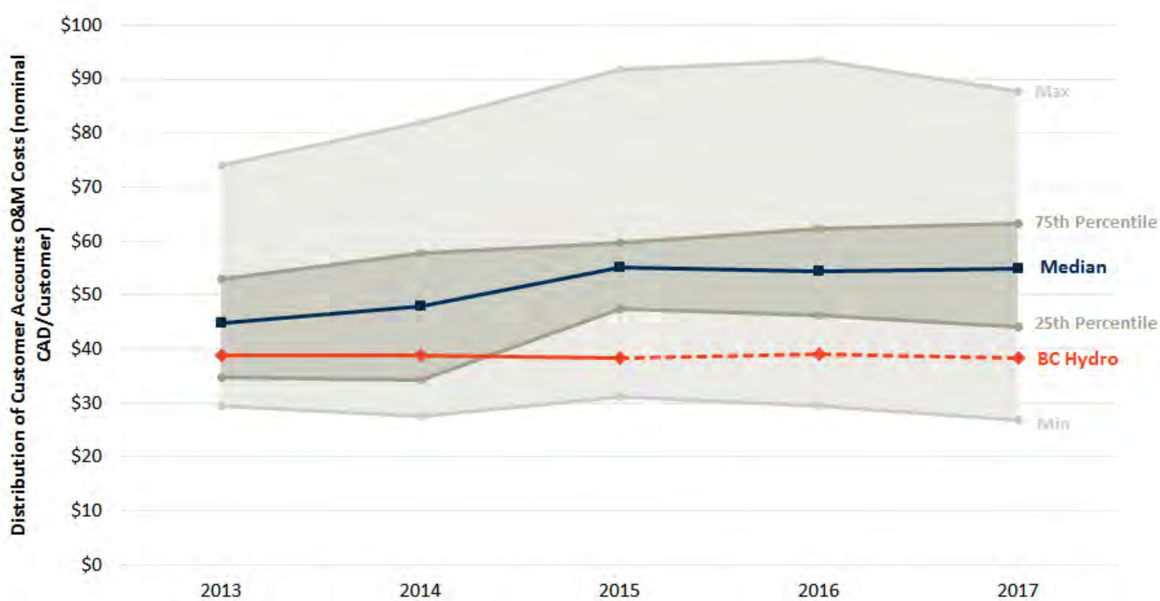
the functional cost areas that make up the broader Customer-Facing area below. Figures D7 and D8 shows cost benchmarking for the Customer Accounts; Figures D9 and D10 for Customer Service and Informational; and Figures D11 and D12 for Sales, all on a $ per delivered MWh and a $ per customer basis.

Figure D7: Customer Accounts O&M Cost Benchmarking ($ per Delivered MWh)



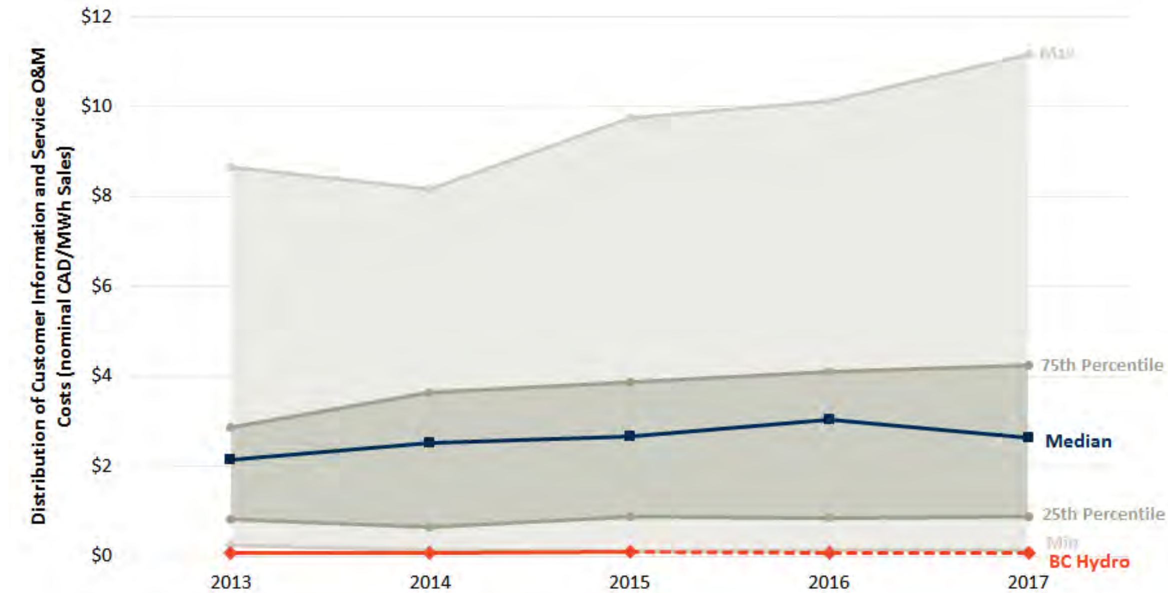
Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (p. 322) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

Figure D8: Customer Accounts O&M Cost Benchmarking ($ per Customer)



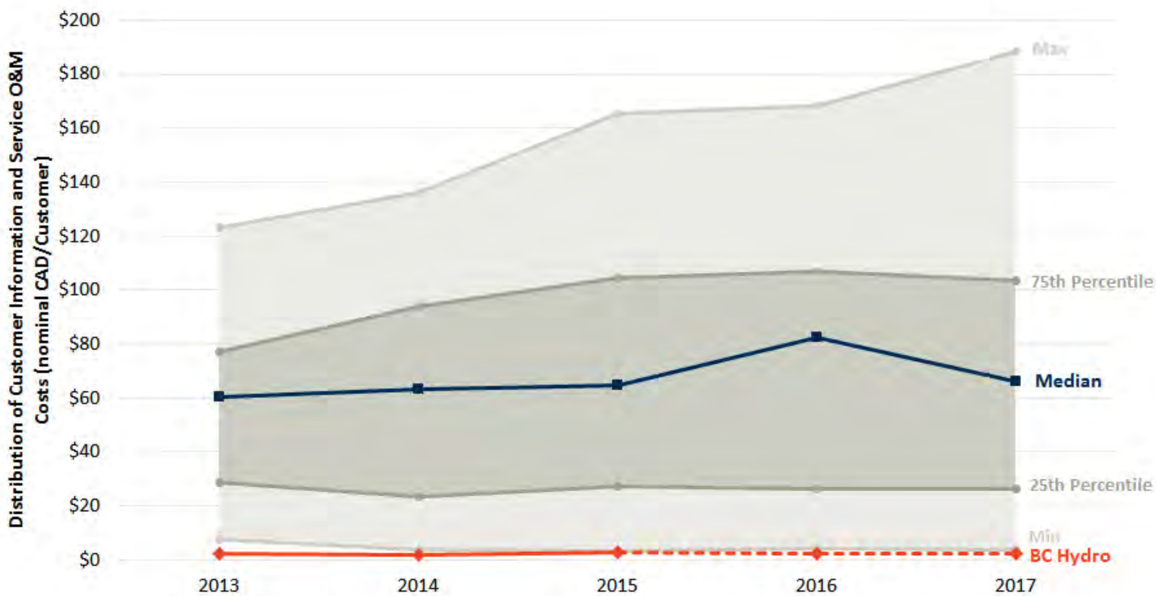
Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (p. 322) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

Figure D9: Customer Service and Informational O&M Cost Benchmarking ($ per Delivered MWh)



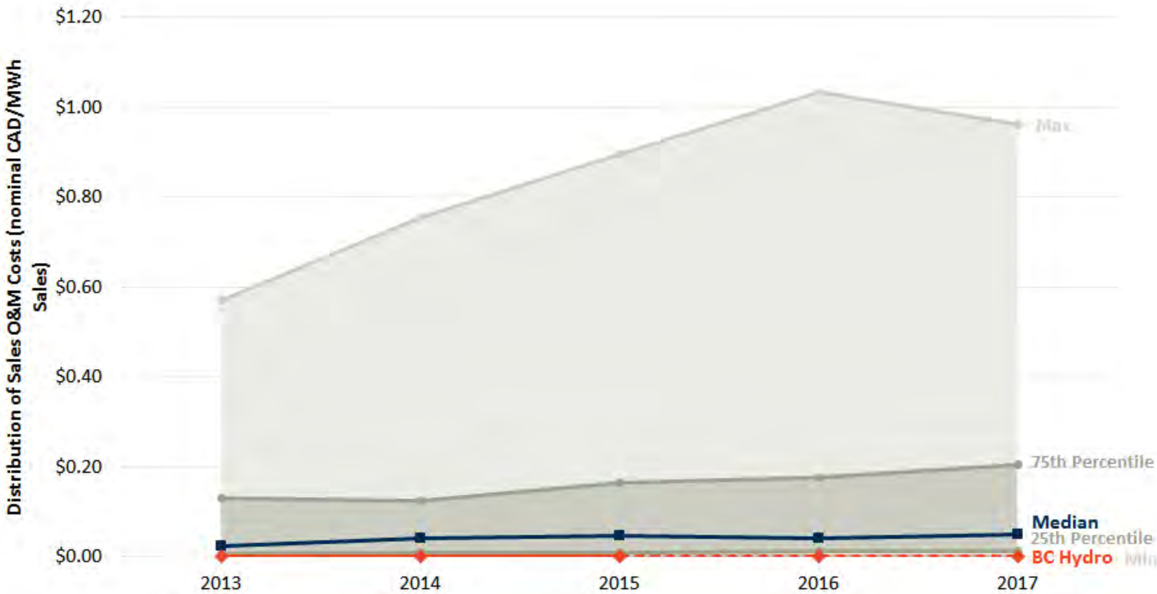
Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (p. 323) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

Figure D10: Customer Service and Informational O&M Cost Benchmarking ($ per Customer)



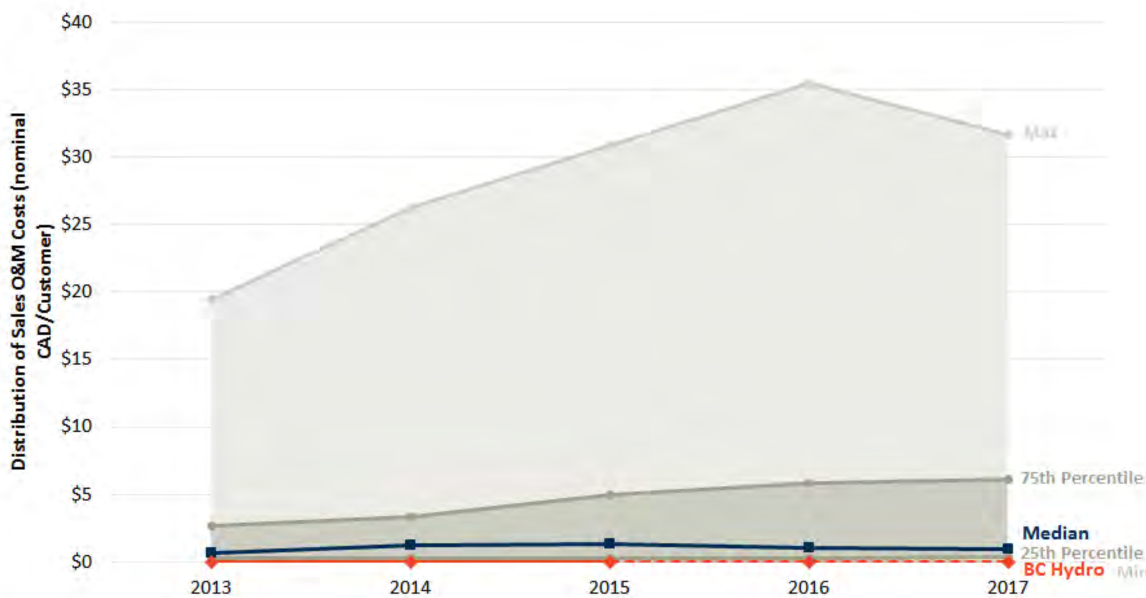
Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (p. 323) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

Figure D11: Sales O&M Cost Benchmarking ($ per Delivered MWh)



Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (p. 323) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

Figure D12: Sales O&M Cost Benchmarking ($ per Customer)



Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (p. 323) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

9. A closer look at the Customer-Facing accounts indicates that several utilities in the panel (as well as BC Hydro) record very little or no expenses to the Customer Service and Informational and/or Sales functional cost areas. Expenses appear to be more consistently reported for Customer Accounts, which includes the costs of meter

reading, customer records and collection, and uncollectible accounts.[7] Figures D7 and D8 indicate that BC Hydro's Customer Accounts O&M costs, which in BC Hydro's case represent the largest portion of the Customer-Facing O&M costs, are within the range of the first quartile on both a $ per delivered MWh and $ per customer basis. For example, in 2015 BC Hydro's per delivered MWh cost in this functional area was $1.31/MWh, between the peer group minimum of $1.01/MWh and the 25th percentile of $1.60/MWh.[8]

10. Figures D9 and D10 show that BC Hydro is just below the minimum of the peer group with respect to Customer Service and Informational O&M costs on both a $ per delivered MWh and $ per customer basis. For example, in 2015 BC Hydro's per delivered MWh cost in this functional area was $0.10/MWh, whereas the peer group minimum was $0.11/MWh.[9] Finally, with respect to Sales O&M, BC Hydro does not classify any costs in these accounts, though it is not alone in doing so; six of the peer group utilities either failed to report costs in these accounts or reported costs so low that they amounted to less than $0.01 per delivered MWh.[10]

D. Administrative and General O&M Costs

11. Figures D13 and D14 show BC Hydro's Administrative and General O&M costs compared to those of the selected U.S. peer panel for 2013 to 2017 on a $ per delivered MWh and $ per customer basis. Administrative and General O&M accounts for roughly 41% of BC Hydro's total NFOM costs. The O&M expenses that are included in the Administrative and General functional category used in this benchmarking

7 These cover USoA accounts 901–905.

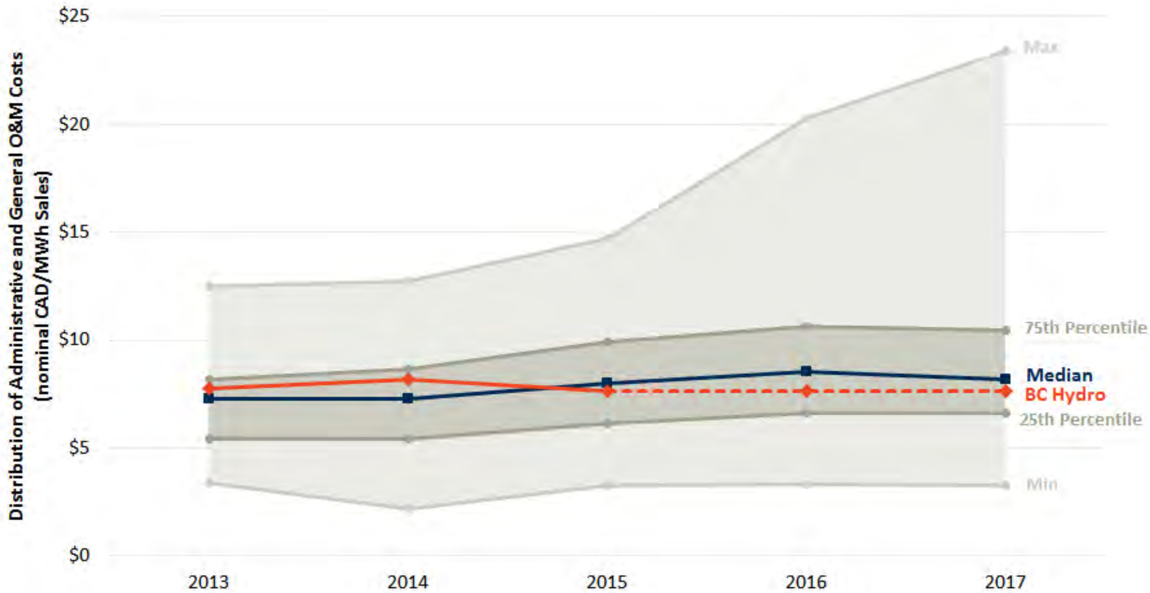
8 For both BC Hydro and the vast majority of the peer utilities, the largest of the Customer Accounts is Account 903 – Customer Records & Collection Expenses. In 2015, BC Hydro spent $27M in this account. However, the majority of U.S. peer utilities spent more; the peer group median was $35M. Similarly, many U.S utilities spent considerably more in Account 904 – Uncollectible Accounts. This is consistent with one of the possible explanations offered by BC Hydro for their stellar performance in this area; namely, that BC Hydro's unusually high smart meter penetration allows for remote service disconnection and reconnection, which facilitates better collections. Note that I have not independently compared BC Hydro's smart meter penetration with that of the U.S. peer group.

9 For the majority of peer group utilities, the account within Customer Service and Informational Expenses O&M that has the largest costs is Account 908 – Customer Assistance Expenses.

10 For the majority of peer group utilities, the account within Sales O&M that has the largest costs is Account 912 – Demonstrating and Selling Expenses.

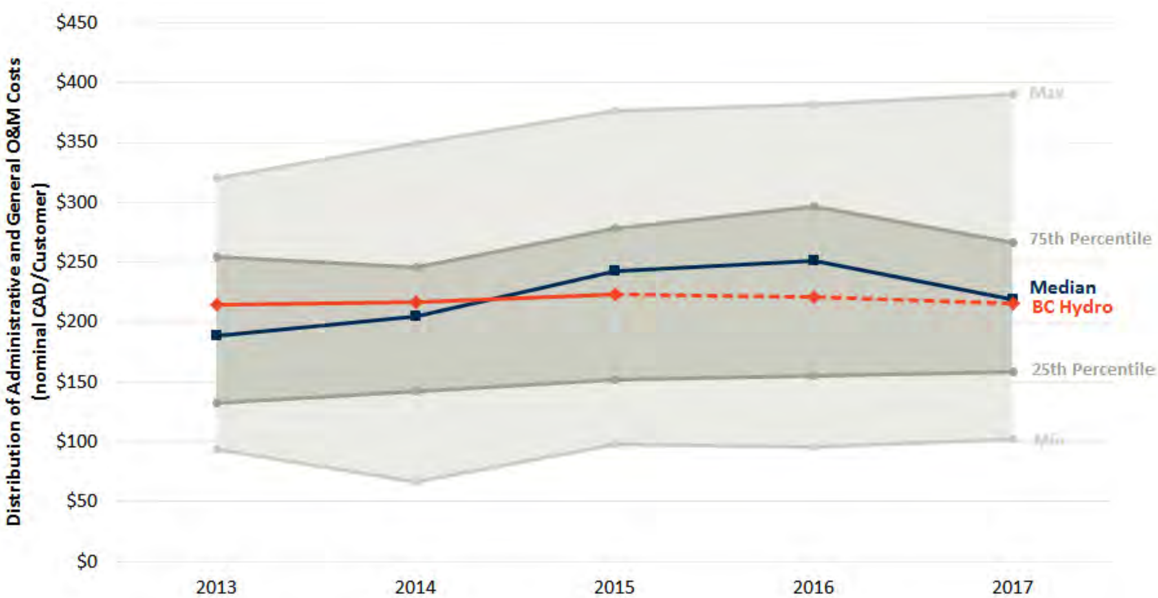
analysis include most of the O&M expenses in the USoA Administrative and General account.[11]

Figure D13: Administrative and General O&M Cost ($ per Delivered MWh)



Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (p. 323) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

Figure D14: Administrative and General O&M Cost ($ per Customer)



Sources: Calculations by The Brattle Group. Values for BC Hydro are based on 2013–2015 USoA data, 2016–2017 total NFOM data, and 2013/14–2017/18 Annual Reports provided by BC Hydro. Values for the U.S. peer panel are based on 2013–2017 FERC Form 1 data (p. 323) and EIA 861 Schedule 4 data, downloaded from Velocity Suite.

[11] This includes USoA accounts 920–926, 928–929, 930.1–930.2, 931, and 935. The only excluded account is 927, which reports costs associated with franchise requirements.

12. BC Hydro’s Administrative and General costs are fairly comparable with those of the peer group, i.e., costs in this category have been similar to the median of the peer group. BC Hydro moved from the third quartile to the second quartile of the peer group in 2015.

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix U

Internal Review of Operating Costs at Comparable Canadian Utilities

BC Hydro - Operating Cost Comparability to Canadian Utilities
Actual Results
($ million)

BC Hydro [1]	Fiscal Year	Operating Costs ($ million) [1, 2]	Sales (GWh) (Domestic) [1]	$/unit of sales (MWh)	Customers (Domestic)[1]	$/customer
	F2018	932	57,173	**16.30**	2,018,044	**461.80**
	F2017	868	57,652	**15.05**	1,987,963	**436.45**
	F2016	829	57,300	**14.47**	1,960,555	**422.99**
	F2015	798	51,213	**15.57**	1,935,068	**412.19**
	F2014	755	53,018	**14.24**	1,914,549	**394.40**

1. Per BC Hydro Annual Report (excludes Powerex and Powertech O&M costs). Manually adjusted to exclude Subsidiary OM costs based on internal financial data. Operating costs also tie to Schedule 5.0 line 15 of Appendix A.
2. Operating costs are reported on a net basis, i.e., does not include regulatory account transfers.
3. Results based on fiscal year reporting under IFRS.

Manitoba Hydro [1]	Fiscal Year	Operating Costs ($ million) [1, 2]	Sales (GWh) (Domestic + Extraprovincial) [1,3]	$/unit of sale (MWh)	Customers (Domestic)[1]	$/customer
	F2018	549	31,953	**17.18**	580,262	**946.12**
	F2017	567	33,238	**17.06**	573,438	**988.77**
	F2016	574	31,935	**17.97**	567,634	**1,011.21**
	F2015	563	32,269	**17.45**	561,869	**1,002.01**
	F2014	491	32,875	**14.94**	555,760	**883.47**

1. Per Manitoba Hydro's Annual Report (above data reported for electric business area including subsidiaries). IFRS based financial statement except for fiscal 2014 (CGAAP).
2. Operating & Administrative Costs have been restated to net view for comparability, based on the information available. (Maintenance costs along with technology, consulting costs, DSM expenditures, restructuring and miscellaneous costs are included within the consolidated amount for "Other Expenses" on the I/S; these costs have either been included/excluded, based on best effort, in order to provide comparability to BC Hydro operating costs).
3. Extraprovincial sales includes Canadian and US export sales (export contracts and sales based on excess energy).
4. Results based on fiscal year reporting.

Hydro Quebec [1,2]	Calendar Year	Operating Costs ($ million) [1,3]	(Domestic + Export) [1,4]	$/unit of sale (MWh)	Customers (Domestic)[1]	$/customer
	2018			-		-
	2017	2,342	205,638	**11.39**	4,279,496	**547.26**
	2016	2,438	201,989	**12.07**	4,244,541	**574.38**
	2015	2,527	201,127	**12.56**	4,214,721	**599.57**
	2014	2,366	200,847	**11.78**	4,179,850	**566.05**

1. Per Hydro Quebec's Annual Report. Includes subsidiary costs.
2. Financial Statements are prepared using US GAAP in Canadian dollars.
3. Operating Costs reported on a net basis. Includes operations expenditures net of 'other components of employee future benefit costs'. However, detail breakdown of these costs is not available in the annual report, hence may include costs other than operating, maintenance and administrative costs. Adjustments, based on best effort, have been made to provide costs that are comparable to BC Hydro's operating costs.
4. Export sales includes sales to New England 57%, New York 23%, Ontario 15%, New Brunswick 6% and Other 4%.
5. Results based on calendar year reporting.

FortisBC Inc. (electricity) [1,2]	Calendar Year	Operating Costs ($ million) [3]	Sales (GWh) [1,5]	$/unit of sale (MWh)	Customers[1,4]	$/customer
	2018			-		-
	2017	64	3,305	**19.36**	136,000	**470.59**
	2016	64	3,121	**20.44**	133,550	**477.72**
	2015	65	3,153	**20.58**	131,883	**492.10**
	2014	67	3,213	**20.74**	130,572	**510.45**

1. Per FortisBC Inc's Management Discussion & Analysis, Annual Information Form, Consolidated Financial Statements. (Benchmark Utility).
2. Financial Statements are prepared using US GAAP in Canadian dollars.
3. Operating Costs reported on a net basis.
4. Electricity sales to direct customers.
5. Sales from regulated and unregulated business
6. Results based on calendar year reporting.

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix V

Electricity Rate Comparison Report No. 11

Ken Peterson
Executive Chair
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

Via email: MEM.Minister@gov.bc.ca

December 11, 2018

Hon. Michelle Mungall
Minister of Energy and Mines and
Petroleum Resources
PO Box 9060 Stn Prov Govt
Victoria BC V8W 9E3

Dear Minister Mungall:

**RE: British Columbia Hydro and Power Authority (BC Hydro)
Electricity Rate Comparison Annual Report No. 11**

BC Hydro writes to file its Electricity Rate Comparison Annual Report (**Report**) which provides a comparison of BC Hydro's monthly bills and average prices for residential, commercial and industrial customers with other North American utilities as of April 1, 2018 (**Attachment A**). The comparison includes BC Hydro's 3.0 per cent rate increase that was effective on that date. The report is prepared in response to *Clean Energy Act* section 8(4), which states that:

> "The authority must provide to the minister, in accordance with the regulations, an annual report comparing the electricity rates charged by the authority with electricity rates charged by public utilities in other jurisdictions in North America, including an assessment of the extent to which the authority's electricity rates continue to be competitive with those other rates."

This Report adheres to the Province of British Columbia's Rate Comparison Regulation (Ministerial Order No. M167) (**Attachment B**). The Rate Comparison Regulation requires that the Report provide a comparison of BC Hydro's monthly electricity bills with at least one public utility in each of at least 15 other North American jurisdictions, including all of the following: the provinces of Alberta, Quebec, Ontario and Manitoba; and the states of Washington, Oregon and California. The comparison uses the previous year's applicable rates for residential, commercial and industrial customers in Canadian funds. In addition, it provides the previous five years of applicable rates for BC Hydro.

The Report consists of information taken from the Hydro-Quebec rate survey report titled "*Comparison of Electricity Prices in Major North American Cities*". The Hydro-Quebec report is prepared each year. Monthly bills and average prices are calculated and submitted to Hydro-Quebec by the participating utilities, including

BC Hydro, using the rates that are in place as of April 1 of that current year. Accordingly, some of the rates used may be interim rates that are approved and in effect at that time.

The 2018 Report indicates that BC Hydro's monthly bills and average prices for all power categories are in the first (i.e., lowest rate) quartile of the public utilities surveyed. On average, BC Hydro's residential rates are third lowest. BC Hydro's small power rates (defined as less than 100 kilowatts (**kW**)) are fifth lowest, medium power rates (defined as 100 kW to 5,000 kW) are fourth lowest, and large power rates (defined as greater than 5,000 kW) are fifth lowest. Applicable BC Hydro rates for each category are listed in Table 11 of Attachment A.

For further information, please contact Fred James at 604-623-4317 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Ken Peterson
Executive Chair

ls/rh

Enclosure

Copy to:

British Columbia Utilities Commission
Attention: Mr. Patrick Wruck
Commission Secretary
Commission.secretary@bcuc.com

Ministry of Energy and Mines
Electricity & Alternative Energy Division
Attention: Les MacLaren
Assistant Deputy Minister
Les.MacLaren@gov.bc.ca

Ministry of Energy and Mines
Deputy Minister's Office
Attention: Dave Nikolejsin
Deputy Minister
Dave.Nikolejsin@gov.bc.ca

BC Hydro Electricity Rate Comparison
Annual Report

Report No. 11

Attachment A

Rates as at April 1, 2018

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List of Tables

Monthly Bills and Average Prices as at April 1, 2018

This is the eleventh Electricity Rate Comparison Annual Report (**Report**) prepared by BC Hydro in response to the Rate Comparison Regulation, issued by Ministerial Order No. M167 under the *Clean Energy Act* on June 28, 2011.[1] The Report provides a comparison of BC Hydro's monthly bills and average prices for residential, commercial and industrial customers with other North American utilities, including those in Alberta, Quebec, Ontario, Manitoba, Washington, Oregon and California in Canadian funds.[2]

Each year BC Hydro participates in the Hydro-Quebec rate comparison survey, submitting bill calculations based on electricity prices that are in place as of April 1 of the current year, and which may reflect approved interim rate increases. Hydro-Quebec compiles the information and provides the monthly bills and average prices for 12 Canadian utilities and 10 American utilities in an annual report. The Report provides survey information taken from the Hydro-Quebec report entitled *Comparison of Electricity Prices in Major North American Cities*.[3]

The Hydro-Quebec report provides the monthly bills, excluding taxes and non-utility levies, calculated for specific consumption points for four different customer segments: residential, small power, medium power and large power. The average price is also calculated, for each customer segment and specific consumption point, by dividing the monthly bill by the amount of monthly energy consumption. For example, if an electric bill for 1,000 kWh was calculated to be a monthly amount of $50, the average price would be $50 divided by 1,000 kWh, or 5 cents/kWh.

1 The first Electricity Rate Comparison Annual Report was issued on June 10, 2009 in response to Ministerial Order No. M114, which was subsequently replaced by Ministerial Order No. M167.

2 Monthly bills and average prices for American utilities have been converted to Canadian dollars using the exchange rate as at 12 p.m. Eastern on April 1, 2018 of $0.7747 (C$1 = US$0.7747). The Canadian dollar had depreciated by 3.74 per cent relative to the U.S. dollar since April 1, 2017.

3 [Hydro Quebec Comparison of Electricity Prices in Major North American Cities Report.]

The monthly bills for customers are presented in Table 1, Table 2, Table 3 and Table 4. The average prices for customers are presented in Table 5, Table 6, Table 7 and Table 8. BC Hydro's monthly bills and average prices over the past five years are summarized in Table 9 and Table 10.

The Hydro-Quebec residential segment includes calculations for BC Hydro's residential customers. The Hydro-Quebec small power segment includes calculations for BC Hydro's general service under 100 kW customers, while the medium power segment includes calculations for BC Hydro's general service 100 kW to 5,000 kW customers. Lastly, the Hydro-Quebec large power segment includes calculations for BC Hydro's general service and transmission service customers who are 5,000 kW and over. Table 11 shows the specific BC Hydro rate schedules that have been included in each Hydro Quebec segment. Table 12 summarizes BC Hydro's relative rankings in each rate class during the last five years of participation in the survey.

Based on the data from the Hydro-Quebec survey, BC Hydro's monthly bills and average prices for the residential, small, medium and large power categories are in the first (i.e., lowest rate) quartile of the public utilities surveyed. These low rates provide a competitive advantage to these customer segments in BC Hydro's service area. The rankings of the top five participating utilities, including BC Hydro, with the lowest monthly bills and average prices are noted in Tables 1 to 8. Of the 22 utilities providing data, BC Hydro's monthly bills and average price rankings against the other utilities are as follows:

Rate Class & Usage	Ranking at April 1, 2018
Residential	
Residential - 625 kWh	3
Residential - 750 kWh	3
Residential - 1,000 kWh	3
Residential - 2,000 kWh	7
Residential - 3,000 kWh	8
Small Power	
Small Power - 750 kWh/6 kW	8
Small Power - 2,000 kWh/14 kW	6
Small Power - 10,000 kWh/40 kW	5
Small Power - 14,000 kWh/100 kW	5
Small Power - 25,000 kWh/100 kW	6
Medium Power	
Medium Power - 100,000 kWh/500 kW	4
Medium Power - 200,000 kWh/500 kW	3
Medium Power - 200,000 kWh/1,000 kW	4
Medium Power - 400,000 kWh/1,000 kW	4
Medium Power - 1,170,000 kWh/2,500 kW	4
Large Power	
Large Power - 2,340 MWh/5,000 kW/25 kV	4
Large Power - 3,060 MWh/5,000 kW/25 kV	3
Large Power - 5,760 MWh/10,000 kW/120 kV	4
Large Power - 17,520 MWh//30,000 kW/120 kV	5
Large Power - 23,400 MWh/50,000 kW/120 kV	5
Large Power - 30,600 MWh/50,000 kW /120 kV	5

Table 1 Residential Monthly Bills

Hydro-Quebec Electricity Prices Comparison Report – Residential
Monthly Bills as of April 1, 2018
CDN $/Month

Utility	City	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Hydro-Quebec	Montreal, QC	(1st) 49	(1st) 57	(1st) 71	(1st) 160	(1st) 251
Manitoba Hydro	Winnipeg, MB	(2nd) 59	(2nd) 70	(2nd) 90	(2nd) 172	(2nd) 254
BC Hydro	Vancouver, BC	(3rd) 64	(3rd) 79	(3rd) 114	(7th) 253	(8th) 393
Newfoundland Power[2]	St. John's, NL	(4th) 81	(4th) 94	(4th) 120	(4th) 225	(4th) 329
Hydro Ottawa	Ottawa, ON	83	(5th) 96	(5th) 122	(3rd) 224	(3rd) 325
NB Power	Moncton, NB	89	103	130	238	346
Florida Power and Light[1]	Miami, FL	(5th) 82	96	125	266	407
Toronto Hydro[1]	Toronto, ON	94	107	132	(5th) 234	(5th) 335
EPCOR Energy	Edmonton, AB	99	114	143	263	382
CenterPoint Energy[1]	Houston, TX	101	118	138	268	399
Pacific Power and Light[1]	Portland, OR	92	108	140	307	474
Seattle City Light	Seattle, WA	86	107	150	321	493
Nashville Electric Service[1]	Nashville, TN	105	122	155	289	422
Enmax	Calgary, AB	108	125	158	291	423
Nova Scotia Power	Halifax, NS	107	126	164	317	471
SaskPower	Regina, SK	112	130	165	307	450
Maritime Electric[1]	Charlottetown, PE	114	132	168	312	426
Commonwealth Edison[1]	Chicago, IL	113	131	167	313	458
DTE Electric[1]	Detroit, MI	131	157	209	416	623
Consolidated Edison[1]	New York, NY	198	233	305	589	873
NSTAR Electric & Gas	Boston, MA	200	239	315	621	928
Pacific Gas and Electric[1]	San Francisco, CA	154	199	297	759	1,318

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

Note: Bill calculations exclude taxes and levies. BC Hydro's bill calculation includes the deferral account rate rider. The top five participating utilities with the lowest monthly bills are ranked in the table above, from lowest to highest. The sort order indicates the utility's overall ranking in the category.

Table 2 Small Power Monthly Bills

Hydro-Quebec Electricity Prices Comparison Report – Small Power
Monthly Bills as of April 1, 2018
CDN $/Month

Utility	City	6 kW 750 kWh 17% load factor	14 kW 2,000 kWh 20% load factor	40 kW 10,000 kWh 35% load factor	100 kW 14,000 kWh 19% load factor	100 kW 25,000 kWh 35% load factor
Manitoba Hydro	Winnipeg, MB	(2nd) 86	(1st) 194	(1st) 883	(1st) 1,764	(1st) 2,310
Hydro-Quebec	Montreal, QC	(1st) 86	(2nd) 209	(2nd) 993	(3rd) 1,820	(3rd) 2,694
Seattle City Light	Seattle, WA	(3rd) 93	(5th) 247	1,237	(2nd) 1,784	(5th) 2,826
Newfoundland Power[2]	St. John's, NL	(4th) 100	258	(3rd) 1,102	1,939	(4th) 2,751
BC Hydro	Vancouver, BC	(8th) 103	(6th) 257	(5th) 1,172	(5th) 1,872	(6th) 2,919
Florida Power and Light[1]	Miami, FL	(5th) 101	(4th) 246	1,233	2,328	3,033
Hydro Ottawa	Ottawa, ON	103	(3rd) 245	(4th) 1,153	2,310	3,639
Enmax	Calgary, AB	150	319	1,208	(4th) 1,869	(2nd) 2,652
CenterPoint Energy[1]	Houston, TX	102	351	1,295	2,322	3,196
NB Power	Moncton, NB	121	284	1,349	2,347	3,366
Toronto Hydro[1]	Toronto, ON	125	277	1,244	2,408	3,745
EPCOR Energy	Edmonton, AB	118	288	1,380	2,534	3,501
Pacific Power and Light[1]	Portland, OR	133	316	1,421	2,384	3,493
SaskPower	Regina, SK	134	305	1,398	2,688	3,650
Nova Scotia Power	Halifax, NS	123	300	1,544	2,715	3,860
DTE Electric[1]	Detroit, MI	133	332	1,582	2,207	3,927
Commonwealth Edison[1]	Chicago, IL	178	378	1,422	2,385	3,484
Maritime Electric[1]	Charlottetown, PE	157	378	1,754	3,021	4,290
Nashville Electric Service[1]	Nashville, TN	174	381	1,606	3,428	4,352
Pacific Gas and Electric[1]	San Francisco, CA	233	598	2,857	4,788	6,866
Consolidated Edison[1]	New York, NY	247	784	2,734	5,182	6,743
NSTAR Electric & Gas	Boston, MA	230	597	3,145	6,009	8,296

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

Note: Bill calculations exclude taxes and levies. BC Hydro's bill calculation includes the deferral account rate rider. The top five participating utilities with the lowest monthly bills are ranked in the table above, from lowest to highest. The sort order indicates the utility's overall ranking in the category.

Table 3 Medium Power Monthly Bills

Hydro-Quebec Electricity Prices Comparison Report – Medium Power
Monthly Bills as of April 1, 2018
CDN $/Month

Utility	City	500 kW 100,000 kWh 28% load factor	500 kW 200,000 kWh 56% load factor	1000 kW 200,000 kWh 28% load factor	1000 kW 400,000 kWh 56% load factor	2500 kW[1] 1,170,000 kWh 65% load factor
Manitoba Hydro	Winnipeg, MB	(1st) 9,773	(1st) 13,717	(1st) 19,323	(1st) 27,211	(1st) 67,203
Hydro-Quebec	Montreal, QC	(5th) 12,100	(2nd) 17,210	24,200	(2nd) 31,969	(2nd) 79,252
Newfoundland Power[4]	St. John's, NL	(2nd) 11,228	(4th) 18,177	(2nd) 21,349	(3rd) 35,112	(3rd) 96,510
BC Hydro	Vancouver, BC	(4th) 12,025	(3rd) 17,979	(4th) 24,042	(4th) 35,949	(4th) 97,827
Enmax	Calgary, AB	12,456	19,159	(5th) 24,170	37,574	101,887
Commonwealth Edison[2]	Chicago, IL	13,294	(5th) 18,652	26,402	(5th) 37,118	(5th) 101,681
Seattle City Light	Seattle, WA	(3rd) 11,766	21,279	(3rd) 23,108	42,125	119,712
Florida Power and Light[2]	Miami, FL	14,433	20,248	28,767	40,397	108,464
Pacific Power and Light[2]	Portland, OR	14,298	22,073	27,272	42,113	106,630
EPCOR Energy[3]	Edmonton, AB	15,496	22,917	28,666	43,509	117,902
DTE Electric[2]	Detroit, MI	15,650	22,515	31,281	44,670	108,402
CenterPoint Energy[2]	Houston, TX	14,793	22,736	32,170	48,056	123,343
NB Power	Moncton, NB	14,499	23,769	28,994	47,534	134,588
SaskPower	Regina, SK	16,348	24,022	32,680	48,028	117,239
Hydro Ottawa	Ottawa, ON	14,830	25,082	29,460	49,963	144,276
Toronto Hydro[2]	Toronto, ON	15,946	26,192	31,513	51,800	143,874
Nova Scotia Power	Halifax, NS	17,146	25,764	34,291	51,527	142,408
Nashville Electric Service[2]	Nashville, TN	18,743	26,573	37,222	52,882	148,733
Maritime Electric[2]	Charlottetown, PE	18,317	29,857	36,572	59,652	168,655
Consolidated Edison[2]	New York, NY	29,924	44,122	59,786	88,183	178,585
Pacific Gas and Electric[2]	San Francisco, CA	33,718	47,396	65,518	91,227	189,921
NSTAR Electric & Gas	Boston, MA	34,047	53,428	67,887	106,650	297,316

1) Supply voltage of 25 kV, customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power rates.

Note: Bill calculations exclude taxes and levies. BC Hydro's bill calculation includes the deferral account rate rider. The top five participating utilities with the lowest monthly bills are ranked in the table above, from lowest to highest. The sort order indicates the utility's overall ranking in the category.

Table 4 Large Power Monthly Bills

Hydro-Quebec Electricity Prices Comparison Report – Large Power
Monthly Bills as of April 1, 2018
CDN $000/Month

Utility	City	5,000 kW 2,340,000 kWh 25 kV 65% load factor	5,000 kW 3,060,000 kWh 25 kV 85% load factor	10,000 kW 5,760,000 kWh 120 kV 80% load factor	30,000 kW 17,520,000 kWh 120 kV	50,000 kW 23,400,000 kWh 120 kV	50,000 kW 30,600,000 kWh 120 kV
Manitoba Hydro	Winnipeg, MB	(1st) 131.9	(1st) 158.6	(1st) 261.2	(1st) 791.7	(1st) 1,125.7	(1st) 1,366.3
Hydro-Quebec	Montreal, QC	(2nd) 135.1	(2nd) 158.6	(2nd) 288.5	(2nd) 873.3	(2nd) 1,265.9	(2nd) 1,501.3
Newfoundland Power[4]	St. John's, NL	(3rd) 190.2	(4th) 239.8	448.7	(3rd) 941.7	(3rd) 1,356.5	(3rd) 1,620.8
Commonwealth Edison[2]	Chicago, IL	202.5	241.0	(3rd) 373.9	(4th) 1,112.0	(4th) 1,566.5	(4th) 1,951.4
BC Hydro	Vancouver, BC	(4th) 195.6	(3rd) 237.9	(4th) 378.5	(5th) 1,147.5	(5th) 1,622.0	(5th) 1,982.7
EPCOR Energy[3]	Edmonton, AB	213.8	260.9	(5th) 406.1	1,219.6	1,750.9	2,091.3
Florida Power and Light[2]	Miami, FL	216.6	256.4	423.1	1,275.8	1,843.1	2,192.5
NB Power	Moncton, NB	202.5	(5th) 240.5	440.2	1,333.1	1,920.3	2,294.7
SaskPower	Regina, SK	225.1	274.8	446.7	1,339.5	1,873.1	2,313.0
DTE Electric[2]	Detroit, MI	216.3	251.3	468.7	1,416.5	2,084.4	2,427.0
Enmax	Calgary, AB	(5th) 201.3	254.5	481.5	1,460.4	2,005.6	2,536.7
Pacific Power and Light[2]	Portland, OR	211.8	258.9	482.4	1,456.2	2,072.8	2,510.1
Service[2]	Nashville, TN	296.3	354.1	422.1	1,245.2	1,812.0	2,136.5
Seattle City Light	Seattle, WA	239.6	307.7	534.3	1,622.9	2,202.1	2,824.1
CenterPoint Energy[2]	Houston, TX	243.9	301.0	541.8	1,640.1	2,276.0	2,842.2
Maritime Electric[2]	Charlottetown, PE	239.6	291.0	556.3	1,685.9	2,395.8	2,909.8
Nova Scotia Power	Halifax, NS	255.0	314.1	598.6	1,815.6	2,550.4	3,140.8
Hydro Ottawa	Ottawa, ON	315.5	330.5	638.2	1,889.1	3,017.5	3,167.5
Toronto Hydro[2]	Toronto, ON	311.5	326.2	647.4	1,938.7	3,103.6	3,258.4
Consolidated Edison[2]	New York, NY	357.0	423.4	813.3	2,461.8	3,568.3	4,231.9
Pacific Gas and Electric[2]	San Francisco, CA	376.5	454.6	867.6	2,623.6	3,742.5	4,522.7
NSTAR Electric & Gas	Boston, MA	575.6	711.2	1,354.3	4,107.3	5,752.9	7,109.0

1) Customer-owned transformer
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

Note: Bill calculations exclude taxes and levies. BC Hydro's bill calculation includes the deferral account rate rider. The top five participating utilities with the lowest monthly bills are ranked in the table above, from lowest to highest. The sort order indicates the utility's overall ranking in the category.

Table 5 Residential Average Prices

Hydro-Quebec Electricity Prices Comparison Report – Residential
Average Prices as of April 1, 2018
CDN ¢/kWh

Utility	City	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Hydro-Quebec	Montreal, QC	(1st) 7.86	(1st) 7.54	(1st) 7.13	(1st) 8.00	(1st) 8.37
Manitoba Hydro	Winnipeg, MB	(2nd) 9.49	(2nd) 9.27	(2nd) 9.00	(2nd) 8.60	(2nd) 8.47
BC Hydro	Vancouver, BC	(3rd) 10.28	(3rd) 10.58	(3rd) 11.42	(7th) 12.67	(8th) 13.09
Newfoundland Power	St. John’s, NL	(4th) 12.98	(4th) 12.56	(4th) 12.03	(4th) 11.24	(4th) 10.97
Hydro Ottawa	Ottawa, ON	13.33	(5th) 12.81	(5th) 12.16	(3rd) 11.18	(3rd) 10.85
NB Power	Moncton, NB	14.27	13.69	12.97	11.89	11.53
Florida Power and Light	Miami, FL	(5th) 13.13	12.85	12.51	13.29	13.55
Toronto Hydro	Toronto, ON	15.09	14.26	13.24	(5th) 11.69	(5th) 11.18
EPCOR Energy	Edmonton, AB	15.79	15.15	14.35	13.15	12.75
CenterPoint Energy[1]	Houston, TX	16.23	15.70	13.75	13.40	13.28
Pacific Power and Light[1]	Portland, OR	14.80	14.44	13.99	15.35	15.80
Seattle City Light	Seattle, WA	13.76	14.32	15.02	16.07	16.42
Nashville Electric Service	Nashville, TN	16.84	16.26	15.53	14.44	14.08
Enmax	Calgary, AB	17.30	16.63	15.79	14.53	14.10
Nova Scotia Power	Halifax, NS	17.06	16.77	16.41	15.87	15.69
SaskPower	Regina, SK	17.87	17.27	16.51	15.37	14.99
Maritime Electric[1]	Charlottetown, PE	18.30	17.65	16.83	15.60	14.21
Commonwealth Edison	Chicago, IL	18.09	17.49	16.75	15.63	15.25
DTE Electric	Detroit, MI	20.95	20.91	20.86	20.79	20.76
Consolidated Edison[1]	New York, NY	31.67	31.13	30.46	29.44	29.11
NSTAR Electric & Gas	Boston, MA	32.06	31.82	31.52	31.07	30.92
Pacific Gas and Electric[1]	San Francisco, CA	24.67	26.58	27.95	37.93	43.93

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.

Note: The top five participating utilities with the lowest average prices are ranked in the table above, from lowest to highest. The sort order indicates the utility’s overall ranking in the category.

Table 6 Small Power Average Prices

Hydro-Quebec Electricity Prices Comparison Report – Small Power
Average Prices as of April 1, 2018
CDN ¢/kWh

Utility	City	6 kW 750 kWh 17% load factor	14 kW 2,000 kWh 20% load factor	40 kW 10,000 kWh 35% load factor	100 kW 14,000 kWh 19% load factor	100 kW 25,000 kWh 35% load factor
Manitoba Hydro	Winnipeg, MB	(2nd) 11.53	(1st) 9.70	(1st) 8.83	(1st) 12.60	(1st) 9.24
Hydro-Quebec	Montreal, QC	(1st) 11.45	(2nd) 10.43	(2nd) 9.93	(3rd) 13.00	(3rd) 10.77
Seattle City Light	Seattle, WA	(3rd) 12.39	(5th) 12.39	12.39	(2nd) 12.73	(5th) 11.32
Newfoundland Power	St. John's, NL	(4th) 13.27	12.92	(3rd) 11.02	13.85	(4th) 11.01
BC Hydro	Vancouver, BC	(8th) 13.77	(6th) 12.86	(5th) 11.72	(5th) 13.37	(6th) 11.67
Florida Power and Light[1]	Miami, FL	(5th) 13.41	(4th) 12.32	12.33	16.63	12.13
Hydro Ottawa	Ottawa, ON	13.73	(3rd) 12.25	(4th) 11.53	16.50	14.56
Enmax	Calgary, AB	20.06	15.94	12.08	(4th) 13.35	(2nd) 10.61
CenterPoint Energy[1]	Houston, TX	13.59	17.57	12.95	16.59	12.78
NB Power	Moncton, NB	16.10	14.21	13.49	16.76	13.46
Toronto Hydro[1]	Toronto, ON	16.71	13.83	12.44	17.20	14.98
Pacific Power and Light[1]	Portland, OR	17.15	15.23	13.73	16.44	13.49
EPCOR Energy	Edmonton, AB	15.70	14.42	13.80	18.10	14.00
SaskPower	Regina, SK	17.82	15.23	13.98	19.20	14.60
Nova Scotia Power	Halifax, NS	16.35	14.99	15.44	19.39	15.44
DTE Electric[1]	Detroit, MI	17.76	16.58	15.82	15.77	15.71
Commonwealth Edison	Chicago, IL	23.78	18.92	14.22	17.04	13.94
Maritime Electric[1]	Charlottetown, PE	20.95	18.90	17.54	21.58	17.16
Nashville Electric Service	Nashville, TN	23.26	19.05	16.06	24.49	17.41
Pacific Gas and Electric[1]	San Francisco, CA	30.59	29.53	28.86	34.70	27.79
Consolidated Edison[1]	New York, NY	32.99	39.18	27.34	37.01	26.97
NSTAR Electric & Gas	Boston, MA	30.63	29.84	31.45	42.92	33.18

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.

Note: The top five participating utilities with the lowest average prices are ranked in the table above, from lowest to highest. The sort order indicates the utility's overall ranking in the category.

Table 7 Medium Power Average Prices

Hydro-Quebec Electricity Prices Comparison Report – Medium Power
Average Prices as of April 1, 2018
CDN ¢/kWh

Utility	City	500 kW 100,000 kWh 28% load factor	500 kW 200,000 kWh 56% load factor	1000 kW 200,000 kWh 28% load factor	1000 kW 400,000 kWh 56% load factor	2500 kW[1] 1,170,000 kWh 65% load factor
Manitoba Hydro	Winnipeg, MB	(1st) 9.77	(1st) 6.86	(1st) 9.66	(1st) 6.80	(1st) 5.74
Hydro-Quebec	Montreal, QC	(5th) 12.07	(2nd) 8.58	(5th) 12.07	(2nd) 7.97	(2nd) 6.76
Newfoundland Power	St. John’s, NL	(2nd) 11.23	(4th) 9.09	(2nd) 10.67	(3rd) 8.78	(3rd) 8.25
BC Hydro	Vancouver, BC	(4th) 12.03	(3rd) 8.99	(4th) 12.02	(4th) 8.99	(4th) 8.36
Enmax	Calgary, AB	12.46	9.58	12.09	9.39	8.71
Commonwealth Edison	Chicago, IL	13.29	(5th) 9.33	13.20	(5th) 9.28	(5th) 8.69
Seattle City Light	Seattle, WA	(3rd) 11.77	10.64	(3rd) 11.55	10.53	10.23
Florida Power and Light[2]	Miami, FL	14.43	10.12	14.38	10.10	9.27
Pacific Power and Light[2]	Portland, OR	14.30	11.04	13.64	10.53	9.11
EPCOR Energy[3]	Edmonton, AB	15.50	11.46	14.33	10.88	10.08
DTE Electric[2]	Detroit, MI	15.65	11.26	15.64	11.17	9.27
CenterPoint Energy[2]	Houston, TX	14.79	11.37	16.09	12.01	10.54
NB Power	Moncton, NB	14.50	11.88	14.50	11.88	11.50
SaskPower	Regina, SK	16.35	12.01	16.34	12.01	10.02
Hydro Ottawa	Ottawa, ON	14.83	12.54	14.73	12.49	12.33
Toronto Hydro[2]	Toronto, ON	15.95	13.10	15.76	12.95	12.30
Nova Scotia Power	Halifax, NS	17.15	12.88	17.15	12.88	12.17
Nashville Electric Service	Nashville, TN	18.74	13.29	18.61	13.22	12.71
Maritime Electric[2]	Charlottetown, PE	18.32	14.93	18.29	14.91	14.41
Consolidated Edison[2]	New York, NY	29.92	22.06	29.89	22.05	15.26
Pacific Gas and Electric[2]	San Francisco, CA	33.72	23.70	32.76	22.81	16.23
NSTAR Electric & Gas	Boston, MA	34.05	26.71	33.94	26.66	25.41

1) Supply voltage of 25 kV, customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.

Note: The top five participating utilities with the lowest average prices are ranked in the table above, from lowest to highest. The sort order indicates the utility’s overall ranking in the category.

Table 8 Large Power Average Prices

Hydro-Quebec Electricity Prices Comparison Report – Large Power
Average Prices as of April 1, 2018
CDN ¢/kWh

Utility[1]	City	5,000 kW 2,340,000 kWh 25 kV 65% load factor	5,000 kW 3,060,000 kWh 25 kV 85% load factor	10,000 kW 5,760,000 kWh 120 kV 80% load factor	30,000 kW 17,520,000 kWh 120 kV	50,000 kW 23,400,000 kWh 120 kV	50,000 kW 30,600,000 kWh 120 kV
Manitoba Hydro	Winnipeg, MB	(1st) 5.64	(1st) 5.18	(1st) 4.54	(1st) 4.52	(1st) 4.81	(1st) 4.47
Hydro-Quebec	Montreal, QC	(2nd) 5.77	(1st) 5.18	(2nd) 5.01	(2nd) 4.98	(2nd) 5.41	(2nd) 4.91
Newfoundland Power[4]	St. John's, NL	(3rd) 8.13	(4th) 7.84	7.79	(3rd) 5.37	(3rd) 5.80	(3rd) 5.30
Commonwealth Edison	Chicago, IL	8.66	7.88	(3rd) 6.49	(4th) 6.35	(4th) 6.69	(4th) 6.38
BC Hydro	Vancouver, BC	(4th) 8.36	(3rd) 7.77	(4th) 6.57	(5th) 6.55	(5th) 6.93	(5th) 6.48
EPCOR Energy[3]	Edmonton, AB	9.14	8.53	(5th) 7.05	6.96	7.48	6.83
Florida Power and Light[2]	Miami, FL	9.26	8.38	7.35	7.28	7.88	7.17
NB Power	Moncton, NB	8.66	(5th) 7.86	7.64	7.61	8.21	7.50
SaskPower	Regina, SK	9.62	8.98	7.76	7.65	8.00	7.56
DTE Electric[2]	Detroit, MI	9.24	8.21	8.14	8.08	8.91	7.93
Enmax	Calgary, AB	(5th) 8.60	8.32	8.36	8.34	8.57	8.29
Pacific Power and Light[2]	Portland, OR	9.05	8.46	8.37	8.31	8.86	8.20
Nashville Electric Service	Nashville, TN	12.66	11.57	7.33	7.11	7.74	6.98
Seattle City Light	Seattle, WA	10.24	10.05	9.28	9.26	9.41	9.23
CenterPoint Energy[2]	Houston, TX	10.42	9.84	9.41	9.36	9.73	9.29
Maritime Electric[2]	Charlottetown, PE	10.24	9.51	9.66	9.62	10.24	9.51
Nova Scotia Power	Halifax, NS	10.90	10.26	10.39	10.36	10.90	10.26
Hydro Ottawa	Ottawa, ON	13.48	10.80	11.08	10.78	12.90	10.35
Toronto Hydro[2]	Toronto, ON	13.31	10.66	11.24	11.07	13.26	10.65
Consolidated Edison[2]	New York, NY	15.26	13.83	14.12	14.05	15.25	13.83
Pacific Power and Light[2]	San Francisco, CA	16.09	14.85	15.06	14.97	15.99	14.78
NSTAR Electric & Gas	Boston, MA	24.60	23.24	23.51	23.44	24.59	23.23

1) Customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

Note: The top five participating utilities including BC Hydro with the lowest average prices are ranked in the table above, from lowest to highest. The sort order indicates the utility's overall ranking in the category.

Table 9 BC Hydro Monthly Bills Summary

BC Hydro Monthly Bills Summary for the Previous Five Years CDN$/Month					
Vancouver, BC	**April 1, 2014 [1]**	**April 1, 2015 [2]**	**April 1, 2016 [3]**	**April 1, 2017 [4]**	**April 1, 2018 [5]**
Residential					
625 kWh	55	58	60	62	64
750 kWh	67	72	74	77	79
1,000 kWh	97	103	107	111	114
2,000 kWh	215	228	238	246	253
3,000 kWh	334	354	368	381	393
Small Power					
750 kWh/6 kW	86	92	95	100	103
2,000 kWh/14 kW	219	233	242	250	257
10,000 kWh/40 kW	1,015	1,075	1,120	1,138	1,172
14,000 kWh/100 kW	1,734	1,836	1,912	1,818	1,872
25,000 kWh/100 kW	2,510	2,658	2,769	2,834	2,919
Medium Power					
100,000 kWh/500 kW	10,207	10,794	11,256	11,660	12,025
200,000 kWh/500 kW	15,310	16,181	16,884	17,443	17,979
200,000 kWh/1,000 kW	20,534	21,720	22,643	23,328	24,042
400,000 kWh/1,000 kW	30,740	32,493	33,889	34,878	35,949
1,170,000 kWh/2,500 kW	83,763	88,570	92,439	94,890	97,827
Large Power					
2,340 MWh/5,000 kW/25 kV	167,643	177,269	185,006	231,493	195,646
3,060 MWh/5,000 kW/25 kV	203,833	215,470	224,920	276,242	237,877
5,760 MWh/10,000 kW/120 kV	322,044	341,362	355,023	463,887	378,505
17,520 MWh//30,000 kW/120 kV	976,368	1,034,937	1,076,363	1,399,442	1,147,546
23,400 MWh/50,000 kW/120 kV	1,380,070	1,462,863	1,521,420	2,013,159	1,622,025
30,600 MWh/50,000 kW /120 kV	1,686,954	1,788,148	1,859,722	2,407,246	1,982,713

1) Rates used reflect a 9.00 per cent approved increase effective April 1, 2014.
2) Rates used reflect a 6.00 per cent approved increase effective April 1, 2015.
3) Rates used reflect a 4.00 per cent proposed increase effective April 1, 2016.
4) Rates used reflect a 3.50 per cent proposed increase effective April 1, 2017.
5) Rates used reflect a 3.00 per cent proposed increase effective April 1, 2018.

Note: Bill calculations exclude taxes and levies and include the deferral account rate rider.

Table 10 BC Hydro Average Prices Summary

BC Hydro Average Prices Summary for the Previous Five Years CDN¢/kWh					
Vancouver, BC	**April 1, 2014 [1]**	**April 1, 2015 [2]**	**April 1, 2016 [3]**	**April 1, 2017 [4]**	**April 1, 2018 [5]**
Residential					
625 kWh	8.75	9.27	9.64	12.10	10.28
750 kWh	9.00	9.54	9.92	11.68	10.58
1,000 kWh	9.71	10.29	10.70	11.15	11.42
2,000 kWh	10.77	11.42	11.88	10.36	12.67
3,000 kWh	11.12	11.80	12.27	10.10	13.09
Small Power					
750 kWh/6 kW	11.53	12.23	12.72	13.37	13.77
2,000 kWh/14 kW	10.97	11.63	12.09	12.49	12.86
10,000 kWh/40 kW	10.15	10.75	11.19	11.38	11.72
14,000 kWh/100 kW	12.39	13.12	13.66	12.99	13.37
25,000 kWh/100 kW	10.04	10.63	11.07	11.34	11.67
Medium Power					
100,000 kWh/500 kW	10.21	10.79	11.26	11.66	12.03
200,000 kWh/500 kW	7.66	8.09	8.44	8.72	8.99
200,000 kWh/1,000 kW	10.27	10.86	11.32	11.66	12.02
400,000 kWh/1,000 kW	7.69	8.12	8.47	8.72	8.99
1,170,000 kWh/2,500 kW	7.16	7.57	7.90	8.11	8.36
Large Power					
2,340 MWh/5,000 kW/25 kV	7.16	7.58	7.91	8.11	8.36
3,060 MWh/5,000 kW/25 kV	6.66	7.04	7.35	7.54	7.77
5,760 MWh/10,000 kW/120 kV	5.59	5.93	6.16	6.38	6.57
17,520 MWh//30,000 kW/120 kV	5.57	5.91	6.14	6.36	6.55
23,400 MWh/50,000 kW/120 kV	5.90	6.25	6.50	6.73	6.93
30,600 MWh/50,000 kW /120 kV	5.51	5.84	6.08	6.29	6.48

1) Rates used reflect a 9.00 per cent approved increase effective April 1, 2014.
2) Rates used reflect a 6.00 per cent approved increase effective April 1, 2015.
3) Rates used reflect a 4.00 per cent proposed increase effective April 1, 2016.
4) Rates used reflect a 3.50 per cent proposed increase effective April 1, 2017.
5) Rates used reflect a 3.00 per cent proposed increase effective April 1, 2018.

Table 11 Corresponding BC Hydro Rate Schedules included in each Segment of the Hydro-Quebec Rate Survey

Hydro Quebec Segment	Corresponding BC Hydro Rate Schedule
Residential	
625 kWh	RS 1101
750 kWh	RS 1101
1,000 kWh	RS 1101
2,000 kWh	RS 1101
3,000 kWh	RS 1101
Small Power	
750 kWh/6 kW	RS 1300
2,000 kWh/14 kW	RS 1300
10,000 kWh/40 kW	RS 1500
14,000 kWh/100 kW	RS 1500
25,000 kWh/100 kW	RS 1500
Medium Power	
100,000 kWh/500 kW	RS 1600
200,000 kWh/500 kW	RS 1600
200,000 kWh/1,000 kW	RS 1600
400,000 kWh/1,000 kW	RS 1600
1,170,000 kWh/2,500 kW	RS 1611
Large Power	
2,340,000 kWh/5,000 kW/25 kV	RS 1611
3,060,000 kWh/5,000 kW/25 kV	RS 1611
5,760,000 kWh/10,000 kW/120 kV	RS 1823
17,520,000 kWh/30,000 kW/120 kV	RS 1823
23,400,000 kWh/50,000 kW/120 kV	RS 1823
30,600,000 kWh/50,000 kW/120 kV	RS 1823

Table 12 BC Hydro Rankings Summary in Hydro-Quebec Rate Surveys, Out of 22 Utilities Surveyed

BC Hydro Rates Comparisons Ranking Summary for Previous Years

Vancouver, BC	April 1, 2014	April 1, 2015	April 1, 2016	April 1, 2017	April 1, 2018
Residential					
625 kWh	3	3	3	3	3
750 kWh	3	3	3	3	3
1,000 kWh	3	3	5	5	3
2,000 kWh	5	7	8	9	7
3,000 kWh	7	8	9	9	8
Small Power					
750 kWh/6 kW	5	5	6	7	8
2,000 kWh/14 kW	4	6	6	7	6
10,000 kWh/40 kW	4	6	8	7	5
14,000 kWh/100 kW	5	5	5	5	5
25,000 kWh/100 kW	4	6	7	8	6
Medium Power					
100,000 kWh/500 kW	3	4	4	4	4
200,000 kWh/500 kW	3	3	4	5	3
200,000 kWh/1,000 kW	3	4	5	5	4
400,000 kWh/1,000 kW	4	4	5	5	4
1,170,000 kWh/2,500 kW	4	4	5	6	4
Large Power					
2,340 MWh/5,000 kW/25 kV	4	4	6	6	4
3,060 MWh/5,000 kW/25 kV	3	5	7	6	3
5,760 MWh/10,000 kW/120 kV	3	6	6	5	4
17,520 MWh//30,000 kW/120 kV	4	7	9	7	5
23,400 MWh/50,000 kW/120 kV	4	7	9	8	5
30,600 MWh/50,000 kW /120 kV	4	7	9	8	5

BC Hydro
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BC Hydro Electricity Rate Comparison
Annual Report

Report No. 11

Attachment B

Ministerial Order No. M 167

PROVINCE OF BRITISH COLUMBIA

REGULATION OF THE MINISTER OF ENERGY AND MINES
AND MINISTER RESPONSIBLE FOR HOUSING

Clean Energy Act

Ministerial Order No. M 167

I, Rich Coleman, Minister of Energy and Mines and Minister Responsible for Housing, order that the Rate Comparison Regulation, B.C. Reg. 140/2009, is repealed, and the following Rate Comparison Regulation is made.

RATE COMPARISON REGULATION

Definition

1 In this regulation:

"Act" means the *Clean Energy Act*;

"applicable rates" means, with respect to a public utility's electricity rates, the average monthly bill for electricity, but not any other terms and conditions of those rates.

Report requirements

2 In a report to be provided to the minister under section 8 (4) of the Act, the authority must do all of the following:

(a) include a comparison with at least one public utility in each of at least fifteen other jurisdictions in North America, including all of the following:

(i) the provinces of Alberta, Quebec, Ontario and Manitoba;

(ii) the states of Washington, Oregon and California;

(b) compare the previous year's applicable rates for residential, commerical and industrial customers with similar rates of the public utilities referred to in paragraph (a);

(c) express the monetary comparisons in Canadian currency;

(d) provide the authority's previous 5 years of applicable rates.

DEPOSITED
JUN 2 8 2011
B.C. REG. 119/2011

JUN 2 8 2011
Date

Minister of Energy and Mines and Minister Responsible for Housing

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Clean Energy Act*, S.B.C. 2010, c. 22, s. 37 (f)

Other: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s. 125.1 (4) (c); M114/2009

June 9, 2011 Resub R/77/2011/27

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Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix W

BC Hydro Reliability Indices

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Fred James
Chief Regulatory Officer
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bchydroregulatorygroup@bchydro.com

May 11, 2018

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Annual Reporting of Reliability Indices
Annual Response to Directive 26 of Commission Decision on F2005/F2006 Revenue Requirements Application (F05/F06 RRA)

BC Hydro writes as required by Directive 26 of the Commission's decision on our F05/F06 RRA to provide an annual reporting of reliability indices.[1]

Directive 26 states that BC Hydro is expected to present reliability indices (SAIFI, SAIDI, CAIDI, ASAI, SARI, MAIFI, generation forced outages, availability, and generation outage rates) both combined and disaggregated (where applicable) on an annual basis with comparisons to Canadian Electricity Association (**CEA**) averages.

In this filing, BC Hydro is providing reliability indices for distribution, transmission and generation performance through F2018. As in previous years, BC Hydro reliability statistics are provided on a fiscal year basis and compared with the CEA calendar year data.

Distribution and Transmission Update

The most recent annual CEA reports for distribution and transmission are the 2016 Annual Service Continuity data on Distribution System Performance in Electrical Utilities and the Bulk Electricity System. CEA data on distribution and transmission

[1] BC Hydro submitted its initial distribution and generation reliability indices compliance filing in September 2005, and subsequently reported the available reliability indices in May 2006 as part of the F2007/F2008 RRA. Starting in May 2007, BC Hydro began filing annual reports with the Commission on these reliability indices. Transmission system reliability indices for the years prior to F2012 were provided separately by the British Columbia Transmission Corporation (**BCTC**) in its Transmission System Capital Plan filings. BC Hydro provided the transmission system reliability indices starting in F2012, subsequent to the integration of BC Hydro and BCTC in F2011.

performance for the 2017 calendar year are not yet available. The comparative reliability indices, both combined and disaggregated for BC Hydro's distribution and transmission systems, are presented in Attachment 1, in tabular and graphical form through to F2018.

Generation Performance Update

The most recent annual CEA report on generation performance is the 2016 Generation Equipment Status Annual Report. CEA data on generation performance for the 2017 calendar year are not yet available. The comparative reliability indices, both combined and disaggregated for BC Hydro's generation system are presented in Attachment 2, in tabular and graphical form for the ten-year period ending F2018.

For further information, please contact Chris Sandve at 604-974-4641 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

(for) Fred James
Chief Regulatory Officer

ls/ma

Enclosures (2)

F05/F06 Revenue Requirements Application

Annual Response to Directive 26 of BCUC Decision

F2018 Annual Reporting of Reliability Indices

Attachment 1

Distribution and Transmission Reliability Indices

This section includes the following distribution and transmission indices:

SAIFI	a measure of the number of sustained interruptions (longer than one minute) an average distribution customer will experience in a year
T-SAIFI-MI	a measure of transmission interruptions of less than one minute in duration that a delivery point experiences in a year
T-SAIFI-SI	a measure of transmission interruptions of one minute or more that a delivery point experiences in a year
T-SAIDI	a measure of the average total interruption duration, in hours that a delivery point experiences in a year
SAIDI	a measure of the amount of time, in hours, an average distribution customer is without power in a year
CAIDI	a measure of the average interruption, in hours, per interrupted distribution customer in a year
%ASAI	a measure of the percentage of time service is available in the year
CEMI-4	percentage of customers experiencing four or more outages in a year
MAIFI	a measure of the frequency of momentary (less than one minute) interruptions per distribution customer served in a year
DPUI	a measure of overall bulk electricity system performance in terms of a composite index of unreliability expressed in system minutes in a year. It takes into account all forced and planned outages except interruptions attributed to generators
SARI	a measure of the average restoration time, in hours, for each transmission delivery point in a year

As noted in Provision 9x of the F2011 Revenue Requirements Application Negotiated Settlement Agreement, BC Hydro is also reporting its CEMI-4 reliability metric, and SAIFI, SAIDI, CAIDI, ASAI, and CEMI-4 metrics normalized using the IEEE 2.5 Beta method. CEMI-4 is not benchmarked externally as utilities are at varying stages in their development of this metric.

Table 1 Reliability Indices – BC Hydro Overall and CEA Overall (All-Event Indices, Not Normalized)

Year	BC Hydro Overall				CEA Overall			
	SAIFI	SAIDI	CAIDI	%ASAI	SAIFI	SAIDI	CAIDI	%ASAI
F1996	1.40	3.04	2.17	99.965	2.80	3.06	1.09	99.965
F1997	1.43	2.95	2.03	99.966	2.39	2.86	1.20	99.967
F1998	1.13	2.00	1.76	99.977	2.35	3.70	1.57	99.958
F1999	1.50	4.23	2.82	99.952	2.40	3.32	1.38	99.962
F2000	1.21	2.28	1.88	99.974	2.59	4.31	1.67	99.951
F2001	1.18	2.51	2.13	99.971	2.26	3.23	1.43	99.963
F2002	1.41	3.60	2.55	99.959	2.41	3.67	1.52	99.958
F2003	1.45	3.77	2.60	99.957	2.33	4.06	1.74	99.954
F2004	1.63	4.51	2.77	99.949	2.67	10.65	3.99	99.878
F2005	1.47	3.96	2.69	99.955	1.98	3.95	2.00	99.955
F2006	1.78	3.82	2.15	99.956	2.13	4.80	2.26	99.945
F2007	2.78	11.40	4.09	99.870	2.53	7.85	3.11	99.910
F2008	1.90	5.68	2.99	99.935	2.32	5.47	2.36	99.938
F2009	1.92	5.24	2.73	99.940	2.34	6.29	2.69	99.928
F2010	1.71	4.25	2.49	99.952	2.01	4.20	2.09	99.952
F2011	1.89	5.28	2.80	99.940	2.20	5.17	2.35	99.941
F2012	1.92	5.08	2.65	99.942	2.63	6.16	2.34	99.930
F2013	1.59	3.70	2.33	99.958	2.54	4.66	1.83	99.947
F2014	1.83	5.19	2.83	99.941	2.72	9.49	3.49	99.892
F2015	1.72	5.11	2.97	99.942	2.39	6.38	2.67	99.927
F2016	2.29	10.69	4.66	99.878	2.32	5.08	2.19	99.942
F2017	2.17	5.50	2.53	99.937	3.10	5.65	1.82	99.936
F2018	2.13	6.56	3.08	99.913	n/a	n/a	n/a	n/a

Table 2 Reliability Indices – BC Hydro (Distribution) and CEA (Distribution) (All-Event Indices, Not Normalized)

Year	BC Hydro (Distribution)				CEA (Distribution)			
	SAIFI	SAIDI	CAIDI	%ASAI	SAIFI	SAIDI	CAIDI	%ASAI
F1996	0.95	2.66	2.78	99.970	1.85	2.51	1.35	99.971
F1997	0.88	2.35	2.64	99.973	1.74	2.39	1.38	99.973
F1998	0.70	1.60	2.28	99.982	1.70	3.21	1.87	99.963
F1999	1.02	3.61	3.54	99.959	1.69	2.82	1.67	99.968
F2000	0.65	1.80	2.78	99.979	1.93	3.80	1.97	99.957
F2001	0.73	1.98	2.72	99.977	1.77	2.83	1.60	99.968
F2002	0.86	2.94	3.43	99.966	1.86	3.19	1.71	99.964
F2003	0.89	3.18	3.59	99.964	1.74	3.55	2.03	99.960
F2004	1.21	3.50	2.89	99.960	1.89	5.69	3.01	99.935
F2005	1.06	3.57	3.35	99.959	1.56	3.49	2.24	99.960
F2006	1.25	3.27	2.61	99.963	1.74	4.33	2.49	99.951
F2007	2.29	10.49	4.58	99.880	2.11	7.35	3.49	99.916
F2008	1.45	5.01	3.44	99.943	1.86	4.94	2.66	99.944
F2009	1.42	4.54	3.21	99.948	1.88	5.65	3.01	99.936
F2010	1.21	3.61	2.98	99.959	1.59	3.63	2.28	99.959
F2011	1.43	4.77	3.34	99.946	1.74	4.65	2.67	99.947
F2012	1.37	4.40	3.22	99.950	2.09	5.59	2.68	99.936
F2013	1.06	3.08	2.92	99.965	1.86	4.13	2.22	99.953
F2014	1.45	4.66	3.20	99.947	2.05	8.59	4.19	99.902
F2015	1.34	4.44	3.31	99.949	1.79	5.67	3.16	99.935
F2016	1.91	10.13	5.30	99.884	1.79	4.54	2.53	99.948
F2017	1.74	4.83	2.77	99.945	2.44	5.08	2.08	99.942
F2018	1.69	5.82	3.44	99.934	n/a	n/a	n/a	n/a

Table 3 Reliability Indices – BC Hydro Overall – Normalized using IEEE 2.5 Beta Method

Year	BC Hydro Overall – Normalized using IEEE 2.5 Beta method				
	SAIFI	SAIDI	CAIDI	CEMI-4 (%)	%ASAI
F2010	1.52	3.50	2.29	13.18	99.960
F2011	1.61	3.83	2.38	15.26	99.956
F2012	1.67	3.89	2.34	15.37	99.956
F2013	1.46	3.33	2.28	10.45	99.962
F2014	1.68	4.14	2.46	12.52	99.953
F2015	1.35	3.37	2.49	10.13	99.962
F2016	1.60	3.42	2.14	14.00	99.961
F2017	1.88	4.37	2.33	16.43	99.950
F2018	1.67	3.94	2.36	14.55	99.955

Table 4 Reliability Indices – BC Hydro CEMI-4 Overall (All-Event Indices, Not Normalized)

Year	BC Hydro Overall
	CEMI-4 %
F2010	15.22
F2011	19.26
F2012	17.43
F2013	12.88
F2014	15.10
F2015	15.15
F2016	23.77
F2017	19.45
F2018	20.87

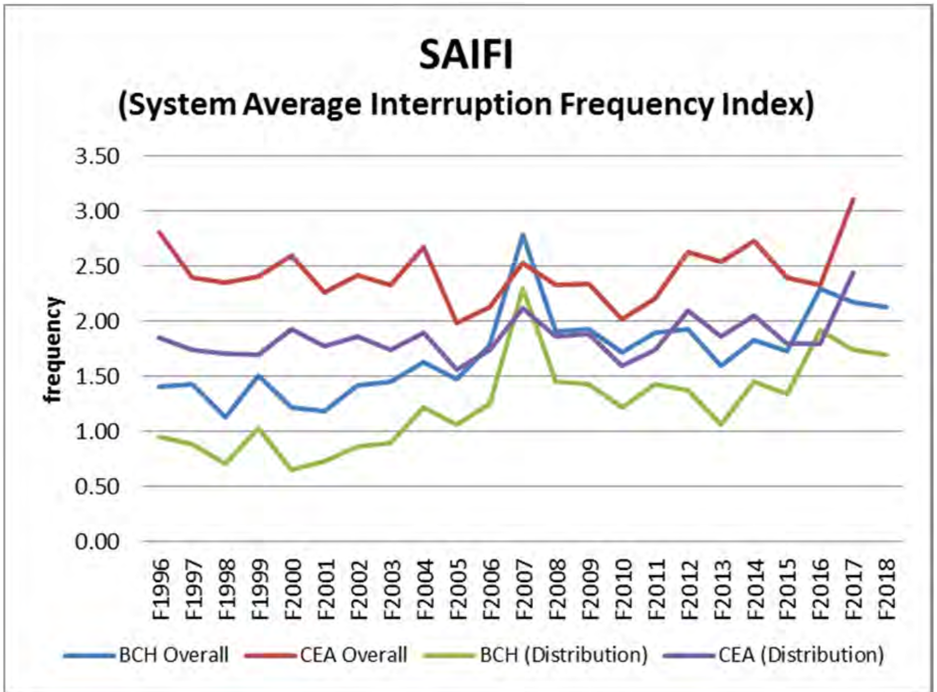
Note: CEA does not survey for CEMI-4 or IEEE 2.5 Beta.

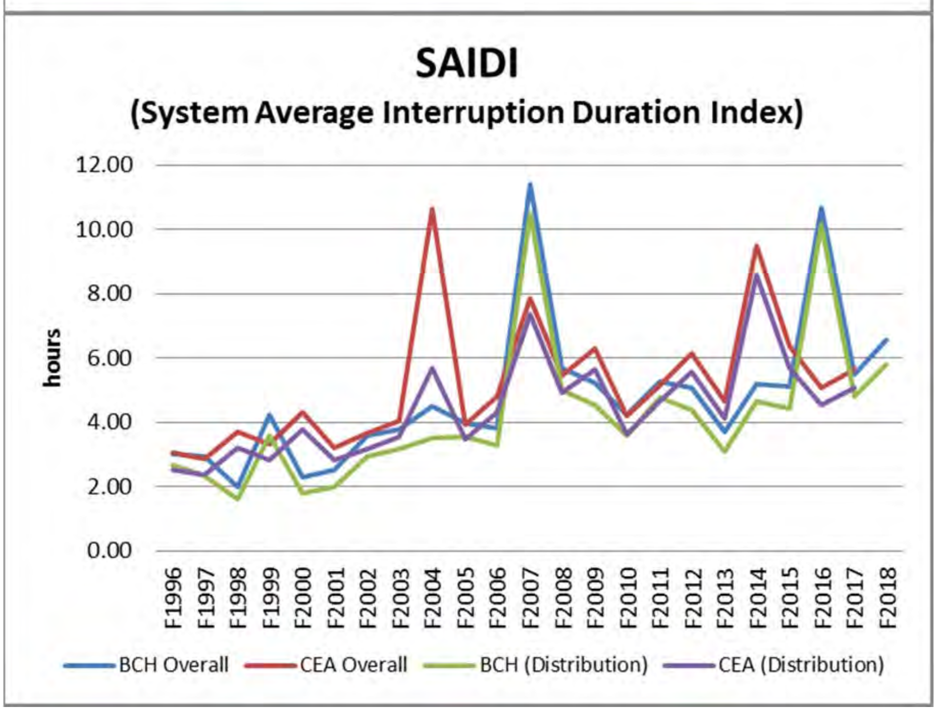
Table 5 Reliability Indices – BC Hydro (Transmission) and CEA (Transmission) (Forced Data) (All-Event Indices, Not Normalized)

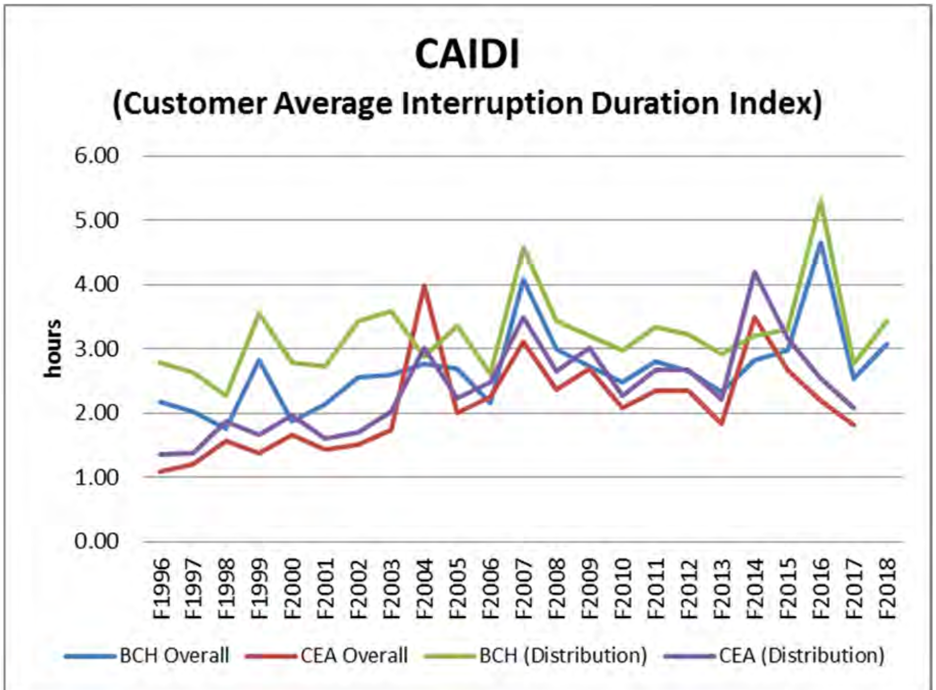
Year	BC Hydro (Transmission) (Forced)					CEA (Transmission) (Forced)				
	T-SAIFI-MI	T-SAIFI-SI	T-SAIDI	DPUI	SARI	T-SAIFI-MI	T-SAIFI-SI	T-SAIDI	DPUI	SARI
F2005	0.90	0.82	1.68	18.02	1.96	0.67	0.85	1.51	21.00	1.65
F2006	0.75	0.91	1.73	25.31	1.87	0.81	0.85	1.29	32.00	1.52
F2007	1.26	1.11	3.80	47.16	1.87	0.91	0.79	1.54	25.51	1.52
F2008	0.87	0.83	2.11	50.54	3.40	0.87	0.74	1.30	18.82	1.94
F2009	0.65	0.72	1.93	35.13	2.42	0.64	0.75	1.23	21.48	1.64
F2010	0.72	1.02	2.31	26.99	2.44	1.01	0.71	1.41	24.98	1.98
F2011	0.38	0.71	1.30	11.31	1.83	0.54	0.64	1.39	13.22	2.16
F2012	0.43	0.86	1.55	19.39	1.81	0.84	0.81	1.73	23.35	2.13
F2013	0.56	0.74	1.64	17.16	2.19	0.84	0.90	4.48	51.18	4.98
F2014	0.74	0.87	2.57	25.18	3.01	0.86	0.83	2.59	27.07	3.11
F2015	0.83	0.74	2.11	26.41	2.86	0.72	0.83	2.56	19.24	3.10
F2016	0.79	0.63	2.46	27.77	3.90	0.85	0.74	2.15	15.60	2.90
F2017	0.63	0.61	2.52	33.61	4.13	0.70	0.75	1.93	22.33	2.58
F2018	0.30	0.69	2.50	30.13	3.62	n/a	n/a	n/a	n/a	n/a

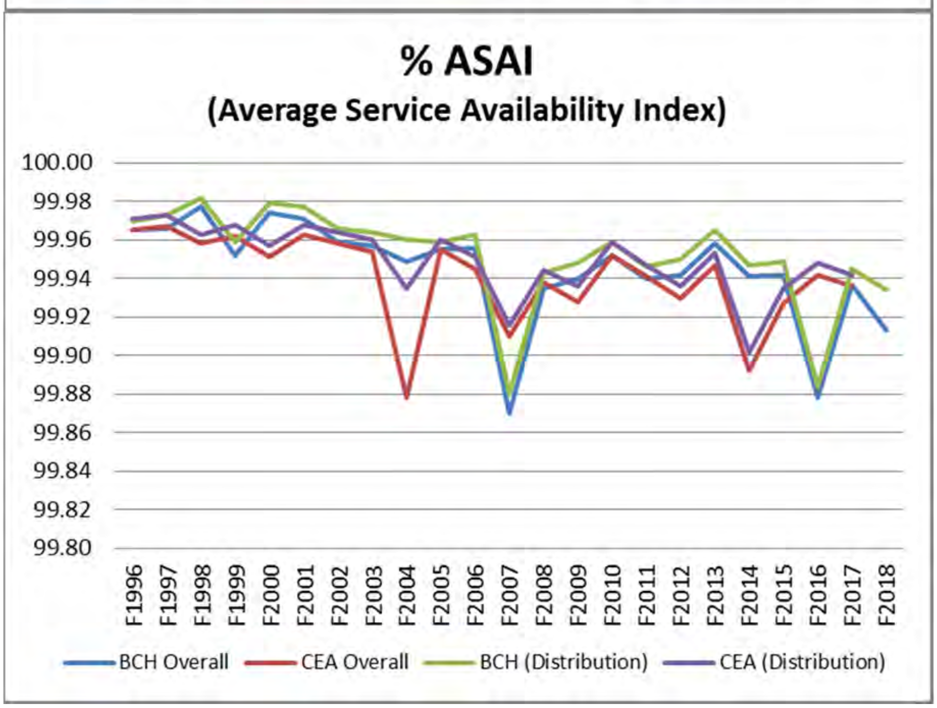
Note: The CEA Bulk Electricity Study program reports only on forced outage results as not all the participating utilities report planned outages.

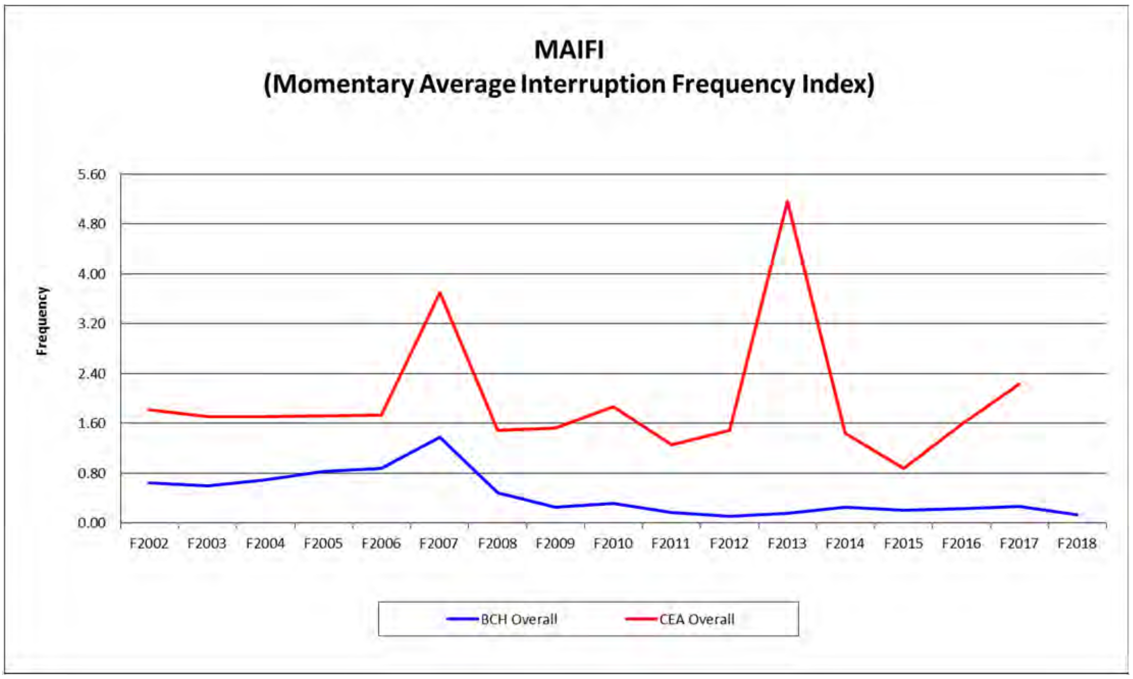
Distribution Graphs





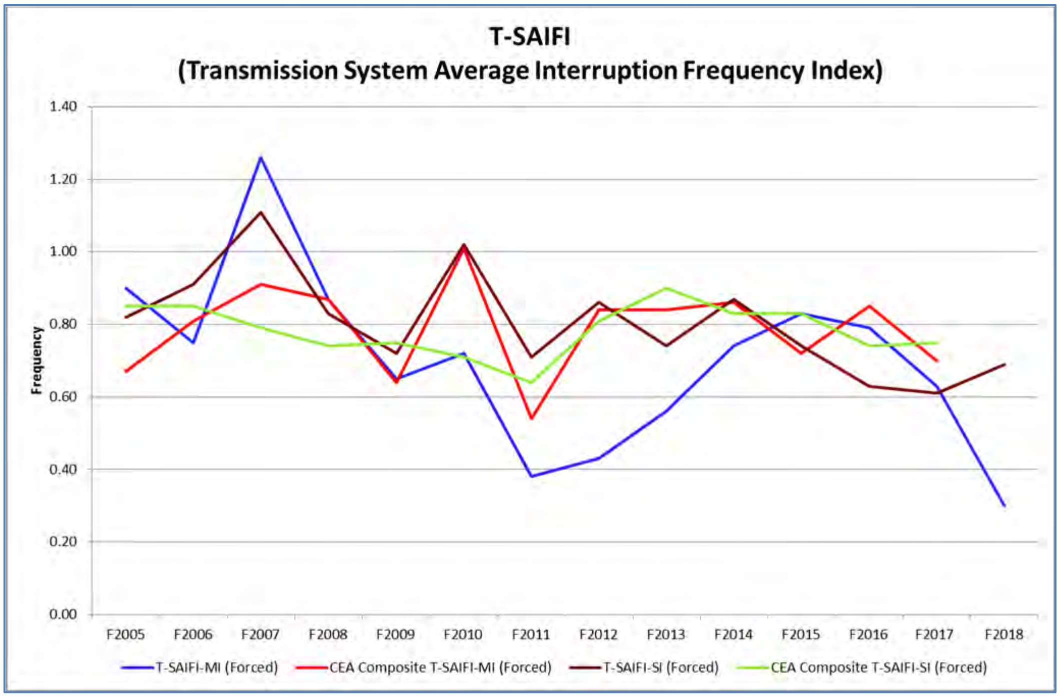

CAIDI
(Customer Average Interruption Duration Index)
hours
6.00
5.00
4.00
3.00
2.00
1.00
0.00
F1996 F1997 F1998 F1999 F2000 F2001 F2002 F2003 F2004 F2005 F2006 F2007 F2008 F2009 F2010 F2011 F2012 F2013 F2014 F2015 F2016 F2017 F2018
BCH Overall
CEA Overall
BCH (Distribution)
CEA (Distribution)

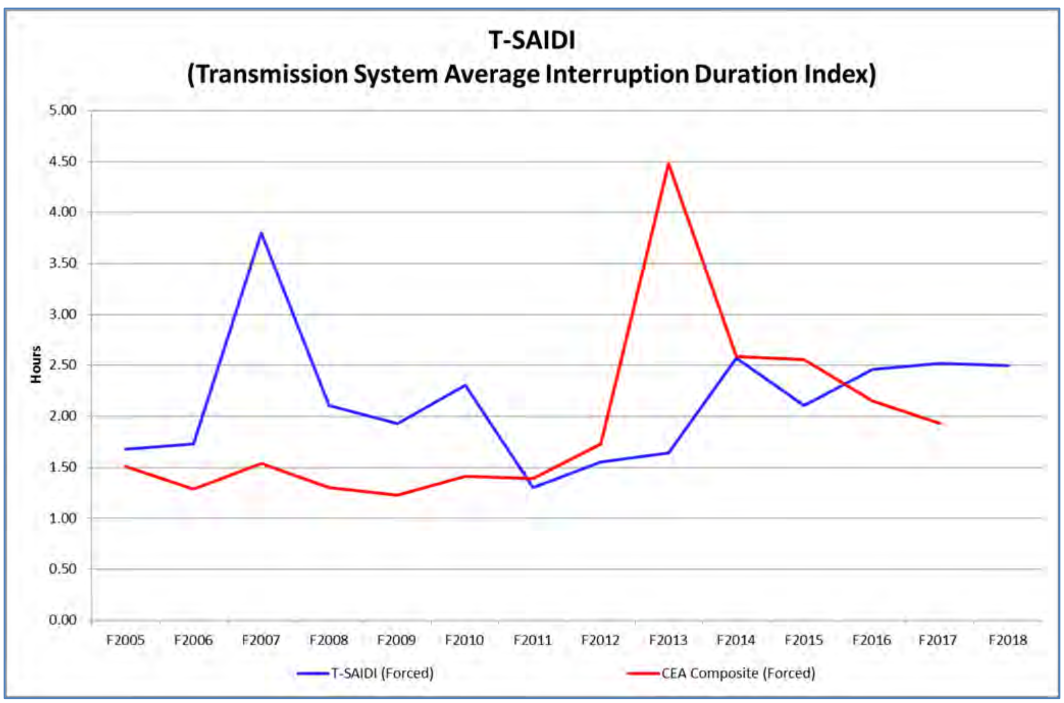

% ASAI
(Average Service Availability Index)
100.00
99.98
99.96
99.94
99.92
99.90
99.88
99.86
99.84
99.82
99.80
F1996 F1997 F1998 F1999 F2000 F2001 F2002 F2003 F2004 F2005 F2006 F2007 F2008 F2009 F2010 F2011 F2012 F2013 F2014 F2015 F2016 F2017 F2018
BCH Overall
CEA Overall
BCH (Distribution)
CEA (Distribution)

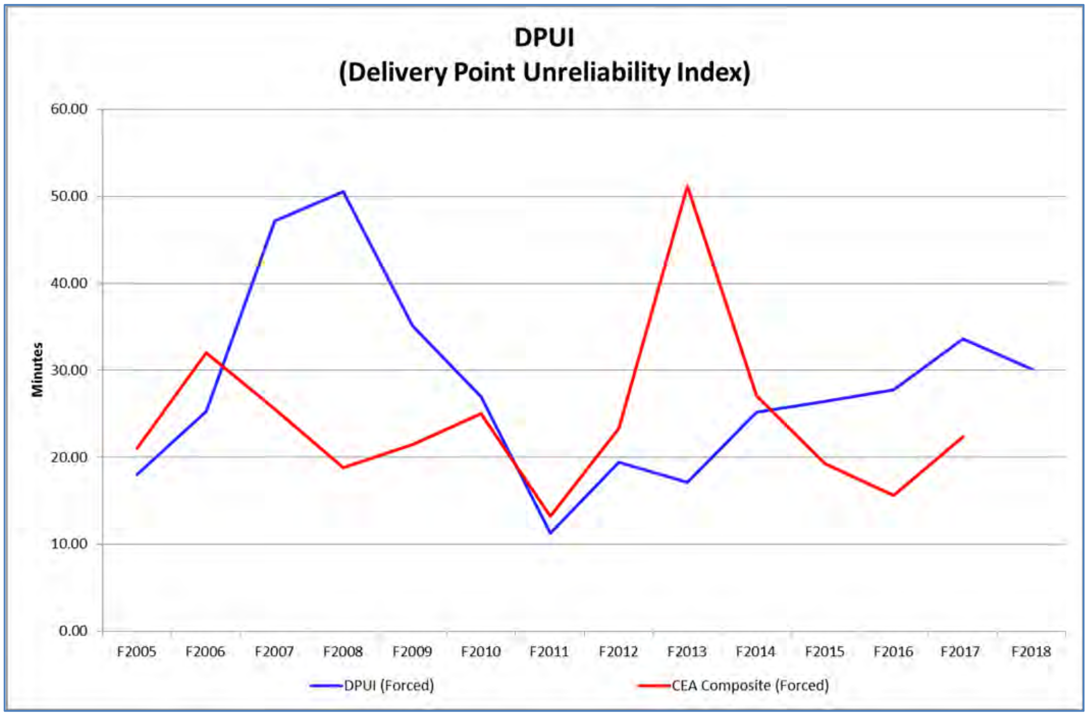


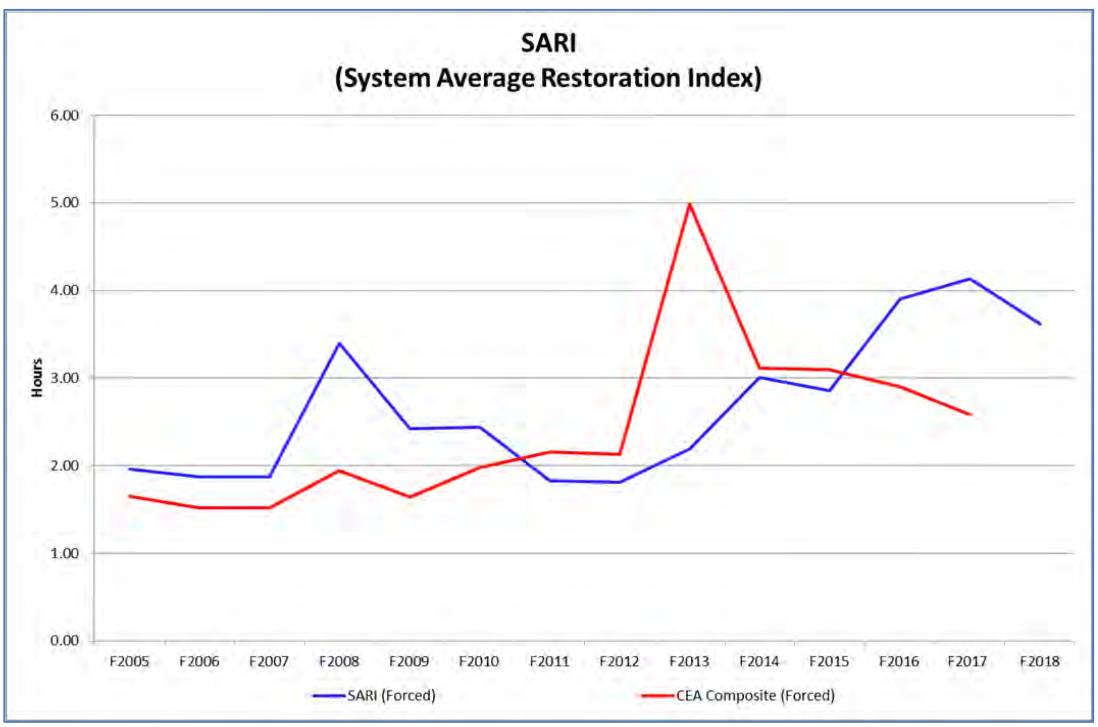
Note: The customer momentary interruptions and the resulting MAIFI may not apply to the utility's total customer population in the CEA comparison. Momentary outages are any interruptions on the feeders of less than one minute duration, caused by disturbance on the distribution, substation or transmission system.

Transmission Graphs






DPUI
(Delivery Point Unreliability Index)
Minutes
60.00
50.00
40.00
30.00
20.00
10.00
0.00
F2005
F2006
F2007
F2008
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
F2017
F2018
DPUI (Forced)
CEA Composite (Forced)


SARI
(System Average Restoration Index)
Hours
6.00
5.00
4.00
3.00
2.00
1.00
0.00
F2005
F2006
F2007
F2008
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
F2017
F2018
SARI (Forced)
CEA Composite (Forced)

BC Hydro
Power smart

F05/F06 Revenue Requirements Application
Annual Response to Directive 26 of BCUC Decision

F2018 Annual Reporting of Reliability Indices

Attachment 2

Generation Reliability Indices

	BC Hydro Hydroelectric Units						CEA Hydroelectric Units				
Fiscal Year	Average Availability Factor (%)	Average Operating Factor (%)	Average Forced Outage Count (Including starting failures) (Internal) Note 1	Average Forced Outage Factor (%) (Including starting failures) (Internal) Note 1	Failure Rate	Calendar Year	Average Availability Factor (%)	Average Operating Factor (%)	Average Forced Outage Count (Including starting failures) (Internal) Note 1	Average Forced Outage Factor (%) (Including starting failures) (Internal) Note 1	Failure Rate
F2009	85.6	71.3	2.0	5.2	2.1	C2008	93.5	80.0	2.5	2.0	2.1
F2010	84.7	68.7	2.1	2.2	2.3	C2009	91.8	77.1	2.4	1.4	2.0
F2011	81.9	68.0	2.0	5.1	1.9	C2010	90.4	70.3	2.2	3.0	1.9
F2012	82.2	69.8	2.4	5.0	2.7	C2011	88.4	72.5	2.5	3.9	2.2
F2013	82.7	72.6	2.0	3.4	2.3	C2012	89.2	72.0	2.5	3.8	2.3
F2014 Note 2	80.5	64.7	2.5	4.7	2.7	C2013	87.9	74.0	2.4	3.9	2.1
F2015 Note 3	81.1	65.1	2.4	3.7	2.9	C2014	87.5	73.5	2.4	5.0	2.1
F2016 Note 3	82.2	65.9	2.0	4.1	2.4	C2015	87.9	70.4	3.2	6.2	2.1
F2017 Note 3	81.7	67.6	1.8	4.4	1.9	C2016	86.7	71.7	3.1	6.2	1.9
F2018 Note 3	80.5	65.5	1.7	2.6	2.0	C2017	n/a	n/a	n/a	n/a	n/a

Definitions

Availability Factor = Operating Time + Available-But-Not-Operating Time / In Commercial Service Time Note 4

Forced Outage Count = Average Number of Forced Outages / Unit / Year (including Starting Failures)(Internal)

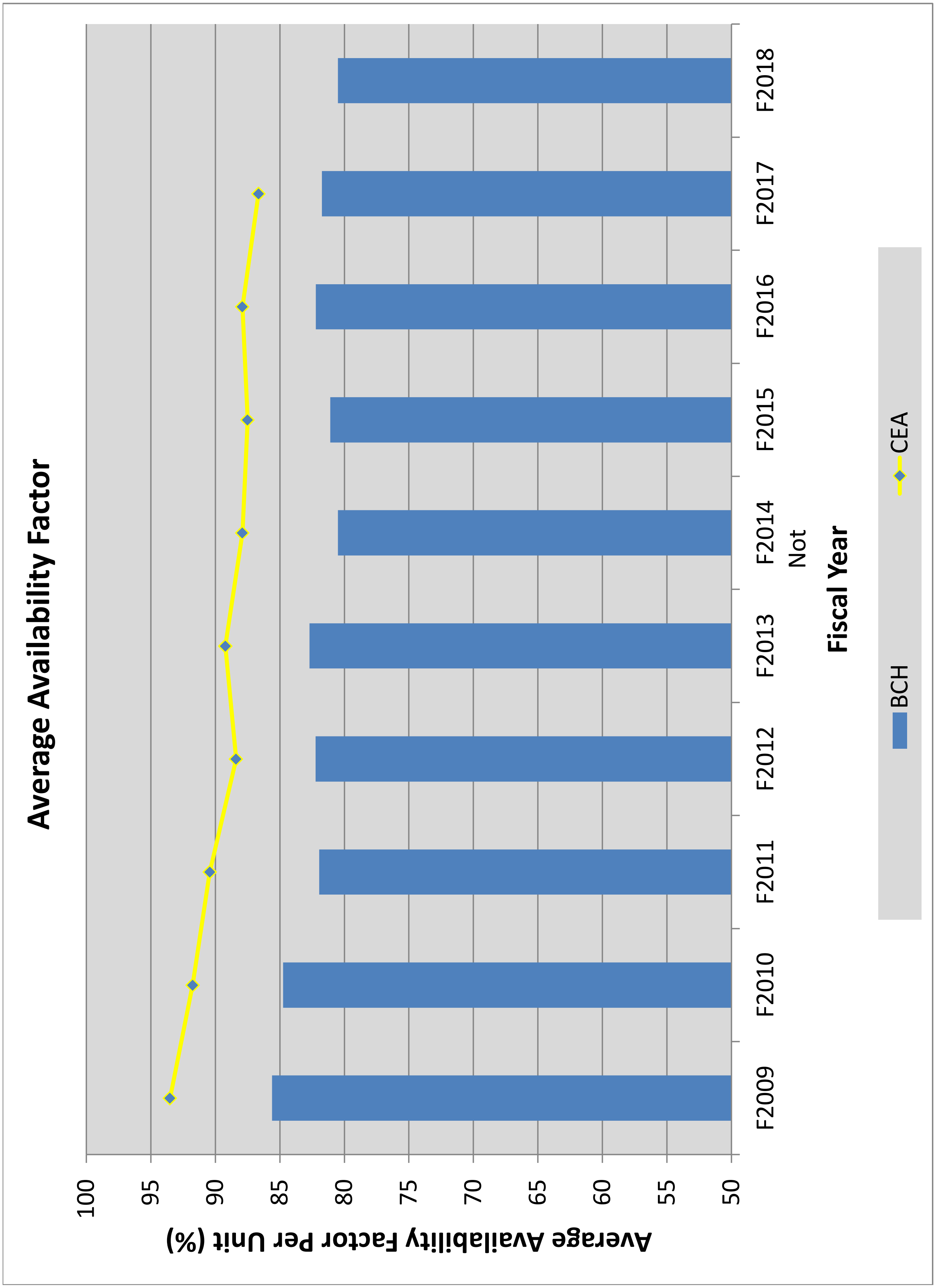
Forced Outage Factor = Forced Outage Time (including Starting Failures)(Internal) / In Commercial Service Time Note 4

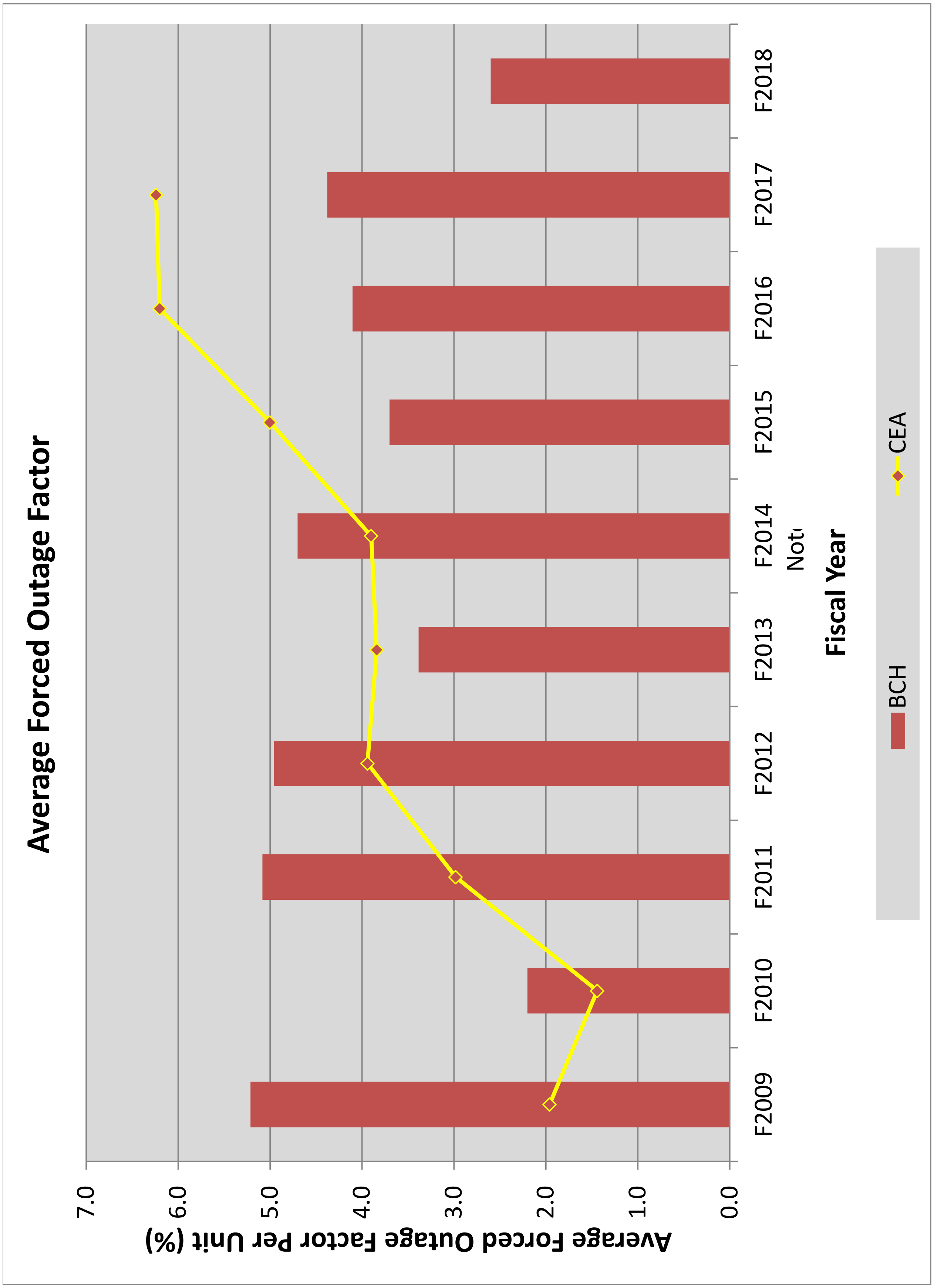
Failure Rate = Forced Outage Count (excluding Starting Failures)(Internal) / Operating Time X In Commercial Service Time Note 4

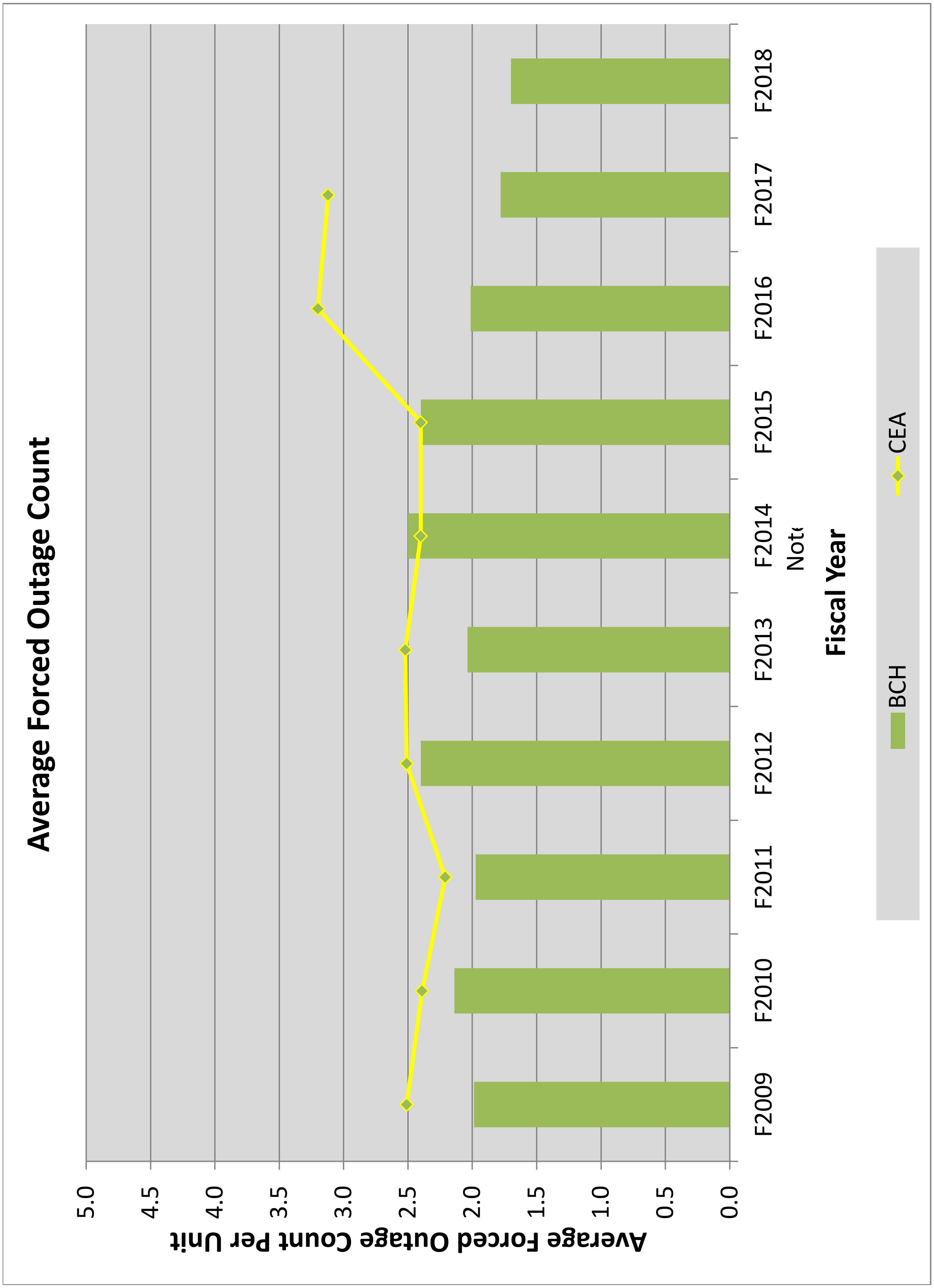
Notes

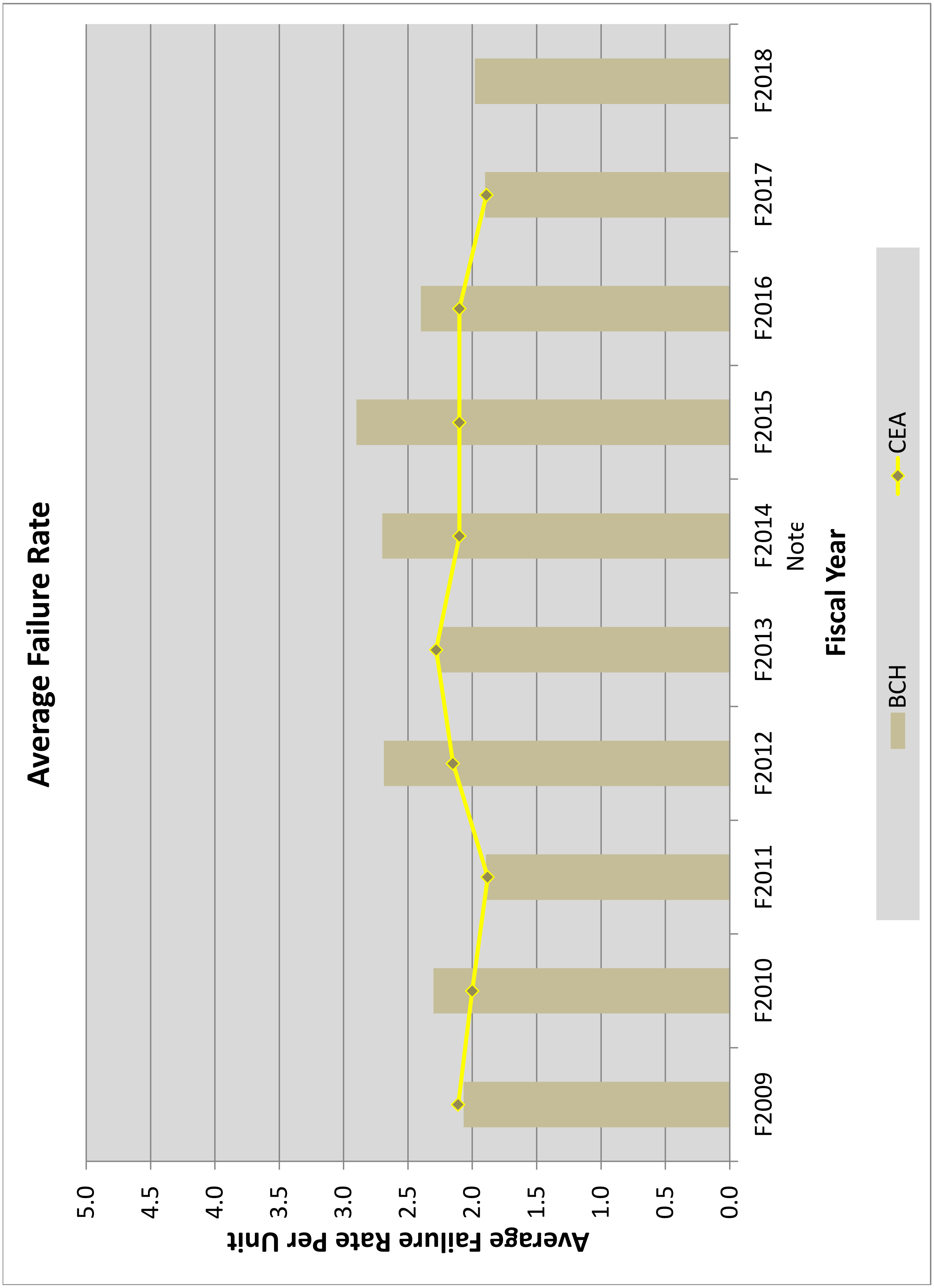
1. Outages with causes that were external to Generation, such as Transmission System forced outages, are excluded from this measure.
2. Data excludes ALU Unit 1 and SHU Unit 1, which have been forced out of service for an extended period.
3. Data excludes ALU Unit 1, SHU Unit 1 and ELK Units 1 and 2 which have been forced out of service for an extended period.
4. In Commercial Service Time represents the number of hours in the measurement period that the unit(s) were considered part of the active fleet.

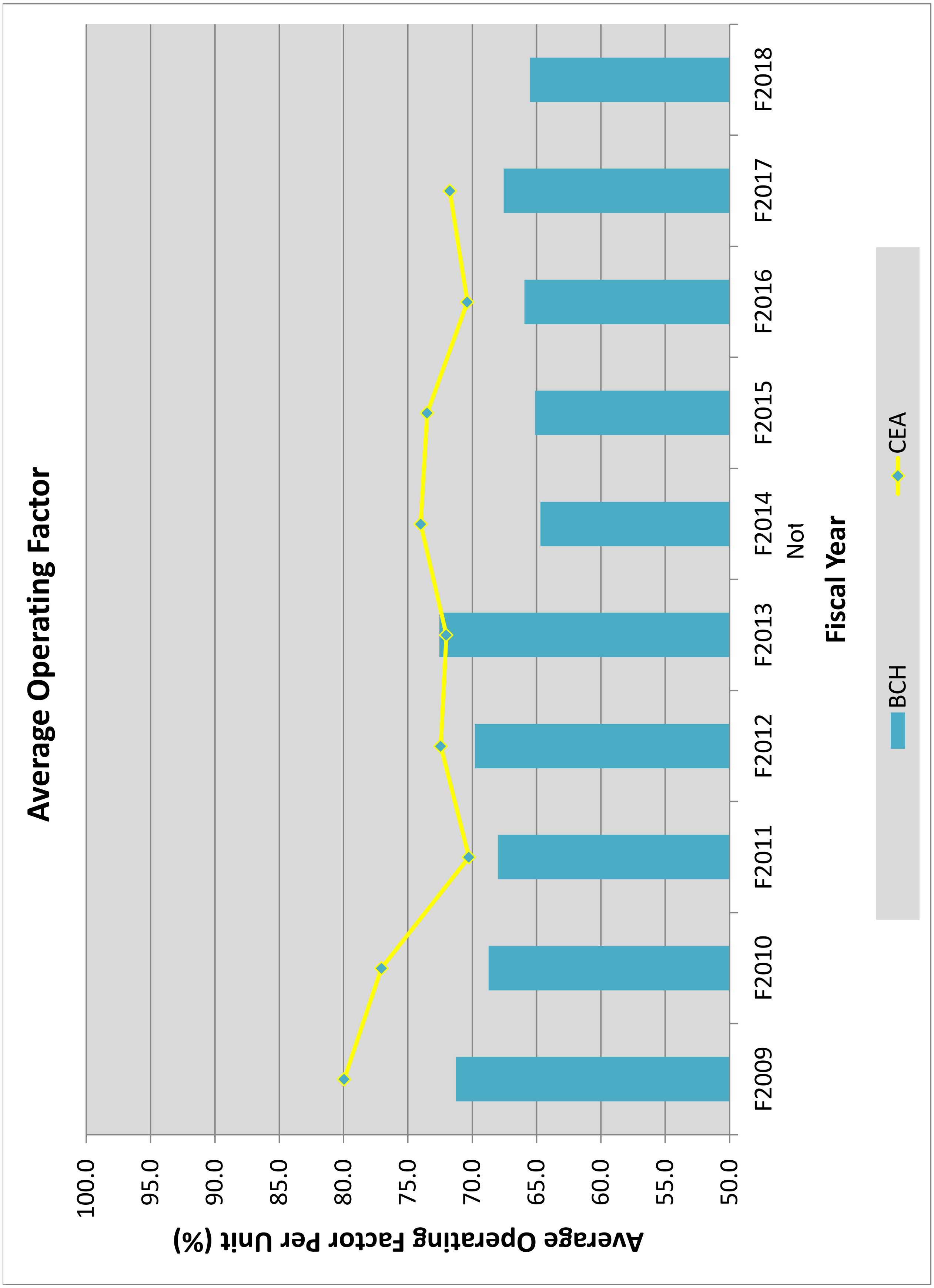
CEA Data taken from table 6.1.1 "All Units"


Average Availability Factor
Average Availability Factor Per Unit (%)
100
95
90
85
80
75
70
65
60
55
50
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
F2017
F2018
Not
Fiscal Year
BCH
CEA


Average Forced Outage Factor
Average Forced Outage Factor Per Unit (%)
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
F2017
F2018
Fiscal Year
BCH
CEA


Average Forced Outage Count
Average Forced Outage Count Per Unit
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
F2017
F2018
Fiscal Year
BCH
CEA


Average Failure Rate
Average Failure Rate Per Unit
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
F2017
F2018
Note
Fiscal Year
BCH
CEA


Average Operating Factor
Average Operating Factor Per Unit (%)
100.0
95.0
90.0
85.0
80.0
75.0
70.0
65.0
60.0
55.0
50.0
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
F2017
F2018
Not
Fiscal Year
BCH
CEA

BC Hydro
Power smart

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix X

Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan

Conservation and Energy Management

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List of Tables

Appendices

1 Demand-Side Management Plan Overview

This section provides an overview of the Demand-Side Management Plan covering the fiscal 2020 to fiscal 2022 period, and provides details of the requested expenditures.

The Plan includes energy-savings tools – programs (energy and capacity), codes and standards and rate structures as well as supporting initiatives to support the Plan's success. Most of the initiatives in the Plan are a continuation of existing activities and build upon knowledge gained in previous years.

The business plan is presented in the following sections:

- Section 1 provides an overview of the Plan and the evolution that has taken place over the past year;
- Section 2 describes the framework used in developing the Plan, and the changes made to respond to customer needs and expectations;
- Section 3 provides more details on the expenditures, energy and capacity savings, other benefits, and cost-effectiveness of the Plan;
- Section 4 demonstrates that the Plan is managed in a comprehensive manner, including assessing ongoing risk factors and management oversight and reporting;
- Section 5 provides the overall sector strategy, descriptions of the individual programs, and cost-effectiveness results for the residential sector
- Section 6 provides the overall sector strategy, descriptions of the individual programs, and cost-effectiveness results for the commercial sector
- Section 7 provides the overall sector strategy, descriptions of the individual programs, and cost-effectiveness results for the industrial sector;
- Section 8 provides a description of the planned capacity-focused trials and pilots
- Section 9 provides a description of codes and standards initiatives which drive and support energy efficiency code and standard development by governments;
- Section 10 provides a description of conservation rates, and

- Section 11 describes the public awareness and administrative activities which support the overall Plan effort.

1.1 Energy-Focused Programs

The Plan includes a suite of programs that deliver a mix of information, access to technology and services, technical assessment and support, and financial assistance to all customer classes to address barriers to cost-effective demand-side management. The programs are designed to capture additional demand-side management potential that remains beyond that obtained from codes and standards and rate structures. In addition, programs are designed to complement rates structures and are critical in setting the stage for changes to codes and standards. The programs are flexible and have been designed to allow for the addition of new technologies or offers including those that might emerge around capacity or low-carbon electrification.

Per the Demand-Side Measures Regulation, a new stand-alone energy management program category called Energy Management Activities has been created in each sector. This was a relabelling of current activities within existing programs that assist customers to optimize energy use and does not represent new activities. This is further discussed in section 2.1.

This plan focuses on demand-side management activities, yet provides the flexibility to efficiently leverage the existing program and operations structure to other initiatives such as low-carbon electrification. This expansion would achieve efficiencies and make it easier for customers to do business with us.[1]

Even as our customers undertake low-carbon electrification activities, it will continue to be important for BC Hydro to help our customers reduce their electricity use through conservation and efficiency, thereby optimizing the electrical system capacity and allowing for further electrification to address climate change. We also need to create opportunities to help our customers shift the timing of when they use electricity to optimize our grid and reduce costs and constraints across BC Hydro's system. Combining the low-carbon

[1] Any expansion into low-carbon electrification activities will come with incremental funding, outside of the expenditures identified in this Business Plan. Such expenditure requests will come forward separately.

electrification initiatives with our traditional demand-side management initiatives will facilitate this focus.

1.2 Capacity-Focused Offers

The Plan continues to include capacity focused pilot and trial offers that were identified in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. The budget has subsequently been extended over a longer period of time, but the total amount of the required budget over fiscal 2017 to fiscal 2021 has been reduced by 12 per cent. Over the fiscal 2020 to fiscal 2022 period, this initiative will identify opportunities to use customer-based, demand-side measures as a resource to manage capacity constraints on the grid. These activities include trials looking at localized demand-side management, behavioural shifting during peak periods, direct control of various technologies, and exploration into the emerging area of Connected Homes and Buildings.

1.3 Codes and Standards

Codes and standards refer to a range of government policy instruments that influence the use of energy, including product/equipment regulations, building codes, tax measures. BC Hydro supports the development of these codes and standards and also works with communities on municipal zoning/building permitting processes, as well as enhanced approaches for Indigenous and remote communities. The Demand-Side Measures Regulation requires codes and standards support initiatives to be undertaken by BC Hydro. The Plan supports and relies upon government implementation of a suite of changes to codes and standards. As a result, BC Hydro does not claim to be exclusively responsible for these savings; however BC Hydro support plays an important role in the achievement of savings. BC Hydro's codes and standards initiatives are coordinated with programs to help drive efficient technologies and practices.

1.4 Rate Structures

Rate structures are changes to the design of electricity rates to provide more economically efficient price signals to customers which encourage conservation. BC Hydro currently has conservation rate structures in place for residential[2] and large industrial (transmission voltage) customers.

1.5 Supporting Initiatives

Supporting initiatives include public engagement and awareness activities and general management and infrastructure. Public engagement and awareness activities are designed to address two specific barriers to demand-side management participation: awareness of ways to increase energy conservation and energy efficiency including through BC Hydro's demand-side management programs, and acceptance of those programs in order to increase participation and seek out energy savings opportunities. General management and infrastructure supports the design, development and implementation of the Plan.

1.6 Plan Overview

In its decision on BC Hydro's Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, the Commission Panel accepted BC Hydro's DSM expenditure schedule.[3] In that proceeding, the Commission examined three different levels of demand-side management, and concluded that BC Hydro had found an appropriate balance. The selected level of demand-side management represents a moderation compared to the level of demand-side management recommended in the 2013 Integrated Resource Plan. This moderation strategy arose in response to the identification of an extended period of surplus electricity and the need to address rate increase pressures. In addition to accepting the overall funding level, the Commission provided findings and directives on a few elements of the Demand-Side Management Plan which have been reflected in this Business Plan.

In developing the F2020-F2022 Demand-Side Management Plan, Conservation and Energy Management has continued with the moderation strategy and its funding envelope, given the continued period of surplus electricity and need to address rate increase pressure. The F2020-F2022 Demand-Side Management Plan also reflects changes in the external and internal considerations outlined in sections 2.1 and 2.2. This has resulted in reductions in

[2] The most recent Residential Inclining Block evaluation report (Evaluation of the Residential Inclining Block Rate F2013-F2017, April 2018) finds that no new incremental savings are anticipated in future years. However, the current pricing signal continues to encourage customers to maintain savings.

[3] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Decision and Order no. G-47-18, March 1, 2018, page 75 of 118.

commercial and industrial expenditures to better align with expected future program spending, and increased expenditures in the residential sector and non-integrated communities to address affordability. The other major change to the Plan was the re-packaging of Energy Management Activities into a new energy management program category.

BC Hydro expects to be working with the Government of B.C. to support a roadmap for the future of B.C. energy. This roadmap along with the completed Conservation Potential Review study will subsequently inform the development of the next Integrated Resource Plan.

Until the energy roadmap and the next Integrated Resource Plan are available, it is reasonable to maintain the current funding envelope for demand-side management, and be prepared to respond when new directions are signaled. The current Demand-Side Management Plan maintains broad access to demand-side management programs and bill savings opportunities, continues to meet the at least 66 per cent target of the *Clean Energy Act*, supports government policy initiatives, and maintains the ability to ramp up in the future.

As a result, the Demand-Side Management Plan presented in this Business Plan provides an appropriate level of investment and savings over the next three years.

The following table summarizes the Plan's contents.

Table 1 Demand-Side Management Tools and Initiatives

Tools	Initiatives	
Programs	Residential	
	• Low Income (with an Indigenous customer offer launching fiscal 2020 or Q4 fiscal 2019) • Non-Integrated Areas (Launching fiscal 2020 or Q4 fiscal 2019)	• Retail • Home Renovation Rebate • Residential Energy Management Activities[4]
	Commercial	
	• Leaders in Energy Management, Commercial • New Construction	• Non-Integrated Areas (combined with residential offer) • Commercial Energy Management Activities[2]
	Industrial	
	• Leaders in Energy Management, Industrial	• Industrial Energy Management Activities[2] • Thermo-Mechanical Pulp
Capacity Focused DSM	• Localized demand-side management – geographically targeted, all sectors • Demand Response – Large Commercial & Small Industrial • Demand Response - Residential appliances, electric vehicle chargers, & devices • Peak Saver - Residential • Connected buildings – Residential, Commercial & Industrial	
Codes and Standards	Product and Equipment Standards	
	• Lighting • Residential appliances	• Residential electronics • Commercial/Industrial Equipment
	Building Codes	
	• B.C. Building Code (Residential and Commercial)	• City of Vancouver Building By-law (Residential and Commercial)
	Codes and Standards Strategy	
	• Sustainable Communities • Codes and Standards Investigation • Residential New Construction support	• Indigenous Communities Policy Support (completing Trial work in fiscal 2019, policy assistance ongoing)
Rate Structures	• Residential Inclining Block	• Transmission Service
Supporting Initiatives	• Public Awareness	• Indirect Support

[4] Per the Demand-Side Measures Regulation, a new program category of "Energy Management" has been established, and existing initiatives which fit into that new categorization have simply been repackaged. This is further discussed in section 2.1.

The following table summarizes planned Demand-Side Management expenditures over the three-year period.

Table 2 Planned Demand-Side Management Expenditure Summary ($ million)

	F2020 Plan	F2021 Plan	F2022 Plan	Total
Codes and Standards	5.2	5.3	5.4	16.0
Rate Structures	0.5	0.5	0.5	1.4
Programs (excluding TMP)	63.7	64.1	64.6	192.4
Capacity-focused	6.9	4.3	0	11.1
Supporting Initiatives	14.6	14.9	15.0	44.4
Total	90.8	89.1	85.5	265.4
Thermo-Mechanical Pulp	0	27.2	0	27.2
Total with Thermo-Mechanical Pulp	90.8	116.2	85.5	292.6

The following table summarizes the cost-effectiveness of the fiscal 2020 to fiscal 2022 demand-side management expenditures (detailed results are presented in section 3.4).

The cost-effectiveness results for the three years of activities (fiscal 2020 to fiscal 2022) are positive as shown in the table below.

Table 3 Benefit Cost Ratios and Net Levelized Costs for Fiscal 2020 to Fiscal 2022 Activities ($/MWh)[5]

	Benefit-Cost Ratios		Net Levelized Costs ($/MWh)[6]	
	Utility Cost Test (Market Price at $30 per MWh)	Modified Total Resource Cost Test (LRMC at $105 per MWh)	Utility Cost Test ($)	Total Resource Cost Test ($)
Codes and Standards	n/a	n/a	n/a	n/a
Rate Structures	11.1	1.4	(4)	73
Programs (including TMP)	1.7	3.6	12	(11)
Rate Structure and Programs (Including TMP)[7]	1.1	2.5	27	14

5 Cost-effectiveness results do not include capacity-focused demand-side management trials and pilots or Codes and Standards benefits.

6 A negative Net Levelized Cost indicates that other non-energy specific benefits such as capacity benefits and customer non-energy benefits (which are characterized as negative costs in the levelized cost formula) exceed the total costs.

7 Also includes Energy Management Activities, Supporting Initiatives and Codes and Standards costs.

1.7 Plan Updates

The Demand-Side Management Plan aligns with relevant requirements in the *Clean Energy Act* and the Demand-Side Measures Regulation. In general, the fiscal 2020 to fiscal 2022 expenditures are consistent with the demand-side management plan previously reviewed by the Commission (F2017-F2019 RRA DSM Plan[8]), with some subsequent expenditure re-allocations made to align with the April 18, 2018 Government Mandate letter and the BCUC Decision recommending more demand-side management programs directed at residential customers. These re-allocations included reductions in commercial and industrial expenditures to better align with expected program spending going forward, and expansions of the Low Income program, Home Renovation Rebate program, and the Non-Integrated Areas program to address affordability.

Overall Plan expenditures, including TMP, are $22.2 million (8.2 per cent) higher over fiscal 2020 to fiscal 2022 compared to the F2017-F2019 RRA Demand-Side Management Plan ($292.6 million vs. $270.4 million), while the sum of the new incremental savings over fiscal 2020 to fiscal 2022 are 9 GWh (0.4 per cent) lower (2,121 GWh vs. 2,130 GWh).

The table below shows the annual expenditures variance between the fiscal 2020-fiscal 2022 Demand-Side Management Plan and the Demand-Side Management Plan in BC Hydro's Fiscal 2017 to Fiscal 2019 Revenue Requirement Application over fiscal 2020 to fiscal 2022. The net increases are primarily due to the spread of expenditures for capacity-focused demand-side management activities over a longer period of time (to fiscal 2021), and an update in the timing of the TMP projects.

Table 4 Utility Costs in F2017-F2019 RRA DSM Plan and F2020-F2022 DSM Plan ($ million)

	F2020	F2021	F2022	Total
F2017-F2019 RRA DSM Plan	85.7	98.4	86.3	270.4
F2020-F2022 DSM Plan	90.8	116.2	85.5	292.6
Variance	5.1	17.9	(0.8)	22.2

[8] Including the updates as per BC Hydro's response to BCUC IR 2.314.3 from the Fiscal 2017 to Fiscal 2019 Revenue Requirement Application.

In addition to these net increases, funding reductions made in the commercial and industrial sectors allowed for the increase in residential affordability initiatives and the introduction of the Non-Integrated Areas program.

The table below compares the expected new incremental energy savings between the F2020-F2022 Demand-Side Management Plan and the Demand-Side Management Plan in BC Hydro's Fiscal 2017 to Fiscal 2019 Revenue Requirement Application over fiscal 2020 to fiscal 2022. Savings were eliminated for the Residential Inclining Block Rate, reduced for commercial programs, increased for residential programs, and updated for existing codes and standards regulations as well including new regulations; and a shift in the savings for general service lamp regulation as new information indicates that it is taking longer than expected for this regulation to drive a turnover in the stock of lamps in BC.

Table 5 New Incremental Energy Savings in F2017-F2019 RRA DSM Plan and F2020-F2022 DSM Plan (GWh/yr)

	F2020	F2021	F2022
F2017-F2019 RRA DSM Plan	632	888	610
F2020-F2022 DSM Plan	700	853	568
Variance	69	(36)	(42)

2 Demand-Side Management Plan Development

This section describes how the Demand-Side Management Plan was developed.

2.1 External Considerations

Development of the Demand-Side Management Plan takes into account a variety of external considerations.

2.1.1 Legislation and Regulation

First and foremost is the provincial legislation and regulation that governs demand-side management in B.C. The Demand-Side Management Plan meets the following legislated or regulated requirements:

- The *Clean Energy Act's* requirement that demand-side measures reduce BC Hydro's expected increase in demand for electricity by at least 66 per cent by the year 2020;
- The adequacy requirements in the Demand-Side Measures Regulation under the *Utilities Commission Act*:
  - ▶ A low income program targeted to low income households;
  - ▶ Measure to improve the energy efficiency of rental accommodations;
  - ▶ An education program for students enrolled in schools;
  - ▶ Education initiatives in post-secondary institutions;
  - ▶ Resources for standards-making bodies to support the development of or compliance with standards; and
  - ▶ Initiatives to encourage the adoption by local government and Indigenous Communities of a building step code and more stringent requirements within a building step code; and
- The Demand-Side Measures Regulation also specifies the various metrics to use in determining that the Plan programs are cost-effective.

The latest update to the Demand-Side Measures Regulation[9] established a new specified demand-side measure, an "energy management program". As defined, an energy management program is "a program to assist customers to optimize energy use". For Conservation and Energy Management, this categorization does not represent new demand-side management activities, but rather encompasses a number of our current initiatives that assist customers to optimize their energy use. For this plan, we have re-packaged those existing energy management related activities into the new specified demand-side measures category for greater transparency with respect to the Demand-Side Measures Regulation. An energy management program has been identified for each of the residential, commercial and industrial sectors, which provides assistance to customers to implement energy savings projects through programs and other initiatives.

2.1.2 Government of B.C. Mandate Letter

The Government of B.C.'s mandate letter to BC Hydro provides another set of considerations in the development of the Demand-Side Management Plan. Each of the government's key priorities articulated in the mandate letter are reflected in our demand-side management initiatives, as identified in the 2018/19 to 2020/21 BC Hydro Service Plan.

Government Priorities	Demand-Side Management Aligns with These Priorities by:
Making life more affordable	This has been accomplished by expanding the Low Income and Home Renovation Rebate programs, and launching the Non-Integrated Areas program. In addition, EE activities generally help to reduce bills for participating customers.
Delivering the services people count on	Supporting customers with initiatives to help them to make smart demand-side management choices through conservation and energy efficiency, capacity reduction and low carbon electrification.
A strong, sustainable economy	We expect to be working with the Government of B.C. in supporting the creation of a roadmap for the future of B.C. energy. Performance measures have been established to achieve new incremental demand-side management savings of 800, 700, and 700 GWh/year, over fiscal years 2019, 2020, and 2021, respectively.

9 B.C. Reg. 117/2017, March 24, 2017

2.1.3 BCUC Decisions

The focus on making life more affordable (with a resulting emphasis on the residential sector) also aligns with Direction 21 from the Commission's decision on BC Hydro's Fiscal 2017 to Fiscal 2019 Revenue Requirements Application,

> "The Panel recommends BC Hydro consider more targeted DSM programs directed at residential customers in the next DSM application"

2.2 Internal Considerations

Development of the Demand-Side Management Plan also takes into account several internal considerations. These include alignment with government and corporate priorities and strategies as described below.

2.2.1 BC Hydro Service Plan

BC Hydro's 2018/19 – 2020/21 Service Plan outlines four strategic goals that guide our actions, each supported by corresponding strategies, performance measures, and targets. Our demand-side management initiatives contribute to each of the strategic goals.

Goal 1 – Set the Standard for Reliable and Responsive Service	This goal is addressed through the strategy of supporting customers with initiatives that help them to make smart demand-side management choices through conservation and energy efficiency, capacity reduction and low-carbon electrification.
Goal 2 - Help Make Electricity More Affordable for our Customers	To address this goal, program expenditures have been increased in the residential sector and a new non-integrated areas program launched, all of which provide additional opportunities for customers to reduce their electricity consumption, and make their bills more affordable.
Goal 3 - Continue British Columbia's Leading Commitment to Renewable Clean Power	This goal is addressed through the strategy of implementing our energy conservation and energy management plan, which will exceed the *Clean Energy Act* requirements to meet at least 66 per cent of future demand growth by 2020. Performance measures have been established for the achievement of new incremental demand-side management savings in each year.
Goal 4 - Safety Above All	This goal is a core value at BC Hydro, and demand-side management activities (in particular, field visits to customer sites) are implemented consistent with this core value.

2.2.2 Conservation and Energy Management Objectives

Conservation and Energy Management's objectives are to provide a broad platform of cost-effective energy management products and services to our customers, and to deliver them efficiently. The Demand-Side Management Plan covers activities focused on energy savings in the residential, commercial and industrial sectors, as well as some initial activities to pursue capacity-focused demand-side management. With incremental funding, Conservation and Energy Management is also able to leverage its capabilities to broaden into low-carbon electrification offers.

An important principle in the design of the Demand-Side Management Plan is the emphasis on building trusted partnerships and transforming marketplaces. Almost every solution works with one or many of the following entities: all levels of government (municipal, regional districts, provincial, and federal), retailers, manufacturers, third-party customer energy analytic providers, and a wide variety of demand-side management service providers that through our guidance and support provide expertise to our customers. This principle helps Conservation and Energy Management drive forward with innovative ideas and keeps pace with a rapidly changing environment.

2.2.3 Development Framework

The Demand-Side Management Plan was also assessed against customer and strategic objectives, along the lines of the framework used in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application:

- Cost effectiveness (Total Resource Cost and Utility Cost perspectives, see section 3.4);
- Flexibility to ramp activities and expenditures up or down, as required
- Support for other BC Hydro or Government initiatives (e.g., Rates Plan);
- Customers broad access to demand-side management programs, and
- Missed demand-side management project opportunities.

2.2.4 Marketplace Information and Conservation Potential Review

Finally, the development of the Demand-Side Management Plan considered the results of the conservation potential review study that was completed in partnership with FortisBC. This review study prepared a conservation potential estimate for electricity and natural gas across all of British Columbia over a 20-year forecast horizon from 2016 to 2035. The review objective was to assess the energy efficiency potential in the residential, commercial, and industrial sectors by analyzing energy efficiency and peak-load-reduction measures, defining operational and maintenance activities to keep existing devices or equipment in good working order, and improving end-user behaviors to reduce energy consumption.

This review has provided both a long-term conservation potential assessment and confirmed the potential for technologies already included in the Plan. Given our current moderation strategy, the conservation potential review study will primarily be used to inform future planning exercises such as the Integrated Resource Plan and the government roadmap for the future of B.C. energy.

2.3 Demand-Side Management Plan Evolution

Conservation and Energy Management has made a numbers of changes to the Demand-Side Management Plan to address the external and internal considerations outlined above, including:

- Launching a new Non-Integrated Areas program to increase support for these remote and predominantly Indigenous communities;
- Increasing participation in the Low-Income program by including Crisis Fund participants in program outreach, and providing Energy Savings Kits at pre-qualified events (e.g., foodbanks, and Indigenous community events) which will not require a BC Hydro account number to receive a kit, introduction of an Indigenous offer within the Low Income Program for customers connected to the integrated BC Hydro electrical system;
- Reducing the budget for commercial and industrial programs to better align with expected future program spending, thus allowing for the expansion of residential initiatives while staying within the overall portfolio funding envelope;

- Aligning the energy management initiatives and sector enabling activities within each sector into an energy management program configuration consistent with the Demand-Side Measures Regulation;
- The Home Renovation Rebate budget was augmented to increase incentives for some measures (e.g., insulation) as well as expand the number of measures (e.g., heat pumps) for electrically heated customers; and
- The Leaders in Energy Management – Commercial program has also launched a new Social Housing Retrofit Support Offer for Multi-Unit Residential, providing an opportunity for qualifying social housing providers to minimize their operating costs and improve whole building performance.

These changes will allow Conservation and Energy Management to continue to respond to customer needs and expectations.

3 Demand-Side Management Plan Expenditures, Savings, Benefits and Cost-Effectiveness

This section provides a more detailed view of the expenditures, energy and capacity savings, other benefits and cost-effectiveness of the fiscal 2020 to fiscal 2022 demand-side management activities.

3.1 Expenditures

The following table summarizes fiscal 2020 to fiscal 2022 demand-side management expenditures.

Table 6 Demand Side Management Expenditure Summary ($ million)

	F2020 Plan	F2021 Plan	F2022 Plan	Total
Codes and Standards	5.2	5.3	5.4	16.0
Rate Structures	0.5	0.5	0.5	1.4
Programs				
Residential	18.4	19.7	21.0	59.1
Commercial	18.9	17.5	17.2	53.7
Industrial	26.5	26.9	26.3	79.7
Total Programs (excluding TMP)	63.7	64.1	64.6	192.4
Capacity-focused	6.9	4.3	0	11.1
Supporting Initiatives	14.6	14.9	15.0	44.4
Total	90.8	89.1	85.5	265.4
Thermo-Mechanical Pulp	0	27.2	0	27.2
Total with Thermo-Mechanical Pulp	90.8	116.2	85.5	292.6

Appendix A provides expenditures at the initiative level by incentive and non-incentive cost. Appendix A also provides a savings forecast to fiscal 2022 at the initiative level.

3.2 Energy and Capacity Savings

A breakdown of forecast energy and associated capacity savings from fiscal 2020 - fiscal 2022 demand-side management activities are provided in the following table. [10]

[10] Capacity savings from capacity-focused demand-side management activities have not been quantified or included.

Table 7 New Incremental Energy Savings and Associated Capacity Savings

	F2020 Plan	F2021 Plan	F2022 Plan
New Incremental Energy Savings (GWh/yr)			
Codes and Standards	356	411	282
Rate Structures	117	118	114
Programs			
Residential	36	36	36
Commercial	59	52	44
Industrial	132	136	92
Thermo-Mechanical Pulp	0	100	0
Total Programs	227	324	172
Total New Incremental Energy Savings	700	853	568
New Incremental Associated Capacity Savings (MW)			
Codes and Standards	79	88	54
Rate Structures	14	14	13
Programs			
Residential	10	10	10
Commercial	9	8	7
Industrial	16	16	11
Thermo-Mechanical Pulp	0	12	0
Total Programs	35	46	28
Total New Incremental Capacity Savings	128	147	95

3.3 Other Benefits

3.3.1 Reduction in Revenue Requirements

The fiscal 2020 to fiscal 2022 total portfolio of the Demand-Side Management Plan is forecast to have a net levelized Utility Cost of $27 per MWh (fiscal 2019 value), which is less than the B.C. border sell price forecast (approximately $30 per MWh).

Using these price forecasts, the demand-side management expenditures (at a net levelized Utility Cost of $27 per MWh) will reduce BC Hydro's revenue requirements, all else being equal. This also results in lower customer bills, on an aggregate basis.

3.3.2 Economic Development Benefits

The implementation of the Demand-Side Management Plan will continue to generate significant economic activity and jobs within the province. These jobs include direct employment through the purchase of labour and materials, spin-off jobs from business activity in the supply chain and the spending of wages, and jobs created by customers spending of energy bill savings from demand-side management. Demand-Side management actions undertaken by customers also make them more competitive through the better use of electricity, creating expanded economic development.

Conservation and Energy Management has updated a study completed by the Deetken Group (Economic Impact Study of BC Hydro's DSM Plan: fiscal 2017-fiscal 2026) which assessed the economic development benefits of the F2017 - F2026 Demand-Side Management Plan that was included in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. For the fiscal 2020 to fiscal 2029 10-year period, economic impacts expressed in terms of GDP, employment and provincial tax revenues are as follows:[11]

- GDP impacts of $1.1 billion;
- Employment of 11,600 full-time equivalent positions; and
- Provincial tax revenue of $115 million.

3.3.3 Environmental Benefits

BC Hydro's electricity is clean, but demand-side management avoids the environmental impacts associated with the construction and operation of new electricity infrastructure. Continued energy efficiency efforts will enable the increased use of BC Hydro's clean electricity and its associated environmental benefits, stretching availability for new electrification opportunities.

3.3.4 Additional Customer Benefits

The implementation of demand-side management initiatives provide customers with additional benefits such as reduced waste generation or product losses, reduced

[11] These values exclude the economic development benefits from codes and standards.

maintenance costs in commercial and industrial facilities, and extended equipment life. These are referred to as customer non-energy benefits, and where they can be quantified, are included in the Total Resource Cost Test.

3.4 Cost Effectiveness

In assessing the Demand-Side Management Plan, BC Hydro included consideration of the cost-effectiveness of demand-side management initiatives using two tests:

- The Utility Cost Test: For the purposes of determining the cost-effectiveness of the fiscal 2020 to fiscal 2022 demand-side management expenditures, BC Hydro relied on the Utility Cost Test, using the market price of electricity to value the energy savings. This test is used to understand the impact of a demand-side management investment on BC Hydro's revenue requirement. Having a positive Utility Cost test result using BC Hydro's market price forecast would provide assurance that even surplus energy resulting from demand-side management would have a positive impact on BC Hydro's revenue requirements; and
- The Total Resource Cost Test: In accordance with the *Demand-Side Measures Regulation*, BC Hydro uses the Total Resource Cost Test as a determinant of whether an individual demand-side management initiative and the demand-side management portfolio as a whole are cost-effective, using the long-run marginal cost of electricity. The Total Resource Cost Test helps BC Hydro to assess how the cost of demand-side management compares to the cost of other supply-side resource options.

The cost-effectiveness of demand-side management initiatives is expressed in terms of three metrics (benefit-cost ratio, levelized cost and net present value). For benefit-cost ratios, higher is better and a ratio of greater than 1.0 means that benefits exceed costs. For levelized costs, lower is better. A negative net levelized cost indicates that non-energy benefits, such as capacity benefits or customer non-energy benefits, exceed the demand-side management costs. A larger negative value is better than a smaller negative value or any positive value. Levelized costs of demand-side management can be compared to the forecast prices of electricity such as the market price or long run marginal cost (LRMC).

The fiscal 2020 to fiscal 2022 demand-side management activities are expected to produce electricity savings at a lower cost than the market price or new supply. As discussed in Chapter 10, the LRMC is out of date, but the net levelized TRC of $14 per MWh indicates that the total portfolio would still be cost-effective against a range of values considerably less than $105 per MWh. The next table presents benefit-cost ratios and net levelized cost for the Demand-Side Management Plan from fiscal 2020 to fiscal 2022 for the two standard demand-side management cost tests: the Utility Cost Test and the Total Resource Cost Test.

Table 8 Benefit Cost Ratios and Net Levelized Costs ($/MWh)

	Benefit-Cost Ratios		Net Levelized Costs ($/MWh)	
	Utility Cost Test (Market Price at $30 per MWh)	Modified Total Resource Cost Test (LRMC at $105 per MWh)	Utility Cost Test ($)	Total Resource Cost Test ($)
Codes and Standards	n/a	n/a	n/a	n/a
Rate Structures	11.1	1.4	(4)	73
Programs (including TMP)[12]	1.7	3.6	12	(11)
Total Portfolio (including TMP)	1.1	2.5	27	14

Appendix A contains more detailed cost test results and the levelized resource costs of individual initiatives.

[12] In previous business plans, a prorated amount of costs from supporting initiatives was added to the cost of each program to assess cost effectiveness of the program per a 2004 BCUC directive. In this table, the allocation of support initiative costs onto programs has not been added, consistent with directions from the Demand-Side Measures Regulation. BC Hydro believes that the Demand-Side Measures Regulation has priority over the 2004 BCUC directive, and during the next Revenue Requirements Application we will be requesting that the directive be rescinded.

4 Demand-Side Management Plan Implementation

This section describes how the Demand-Side Management Plan is implemented by Conservation and Energy Management.

4.1 Governance and Change Process

4.1.1 Governance:

The Demand-Side Management Plan will be managed through the structure and controls built in the Conservation and Energy Management governance process, which is managed by the Conservation and Energy Management Steering Committee.

The Conservation and Energy Management Steering Committee monitors the performance of programs and initiatives on an ongoing basis and approves adjustments as required to ensure their appropriate performance. The primary performance metrics for the Demand-Side Management Plan are energy savings and costs.

4.1.2 Change Process

The Demand-Side Management Plan are reviewed and approved by the appropriate authority before implementation. Any subsequent deviations from the approved Plan will be managed through consultation, review, and approval from the appropriate parties.

4.1.3 Monitoring & Reporting:

The Management Steering Committee will monitor performance of the Demand-Side Management Plan on an ongoing basis, and report the performance to its stakeholders as required. The stakeholders include, but are not limited to the People, Customer & Corporate Affairs Management Team, BC Hydro Executive team and the BC Hydro Board.

4.2 Risk Management

Conservation and Energy Management's approach to demand-side management performance management is informed by the identification and assessment of related risks and the development of mitigation measures at various stages in the demand-side management process, from initiative design through implementation to evaluation. Risks are assessed and managed at the portfolio, initiative, and project level. This section describes the material risks that have been identified and key risk mitigation tactics undertaken for the three demand-side management tools and the Demand-Side Management Plan as a whole.

4.2.1 Codes and Standards Risks and Mitigation

The principal risks as they relate to codes and standards are:

- **Approval Risk:** Planned codes and standards are not approved by Government, or not approved at the planned time;
- **Coverage Risk:** Codes and standards do not cover as many technologies or building types as expected or prescribe less efficient standards than expected; and
- **Compliance Risk:** The level of compliance with a code or standard is less than expected.

A key aspect of codes and standards risk mitigation is that Conservation and Energy Management does not have direct control over the implementation of codes and standards and relies on the action of governments to deliver these savings. Thus there is uncertainty regarding the timing, coverage and efficiency level of codes and standards outlined in the Demand-Side Management Plan. These risks are mitigated in part by Conservation and Energy Management using its influence to support the implementation of codes and standards through its demand-side management programs and codes and standards supporting initiative.

In addition, Conservation and Energy Management monitors government approval of codes and standards and uses the best available information, including results from completed evaluations, to estimate codes and standards savings. As new information becomes available, Conservation and Energy Management incorporates this information into its estimates of codes and standards savings. If it becomes apparent that codes and standards savings might be less than planned, Conservation and Energy Management can respond in a number of ways, for example: Consider expanded demand-side management programs to capture some of the savings expected from a code or standard.

4.2.2 Rate Structure Risks and Mitigation

The principal risk as it relates to rate structures is:

- Customer Response Risk: The customer response to the rate structure is lower than expected.

As discussed in BC Hydro's 2015 Rate Design Application, this risk materialized with the Large General Service and Medium General Service rate structures, where evaluations found that energy savings from these rates were considerably less than planned.

BC Hydro mitigates this risk in several ways during design and implementation. First, BC Hydro has a rate design process that includes customer consultations, and culminates in a transparent public review of BC Hydro's rate design application by the British Columbia Utilities Commission. Second, the customer response to rate structures is forecasted using the best available information. As new information becomes available, BC Hydro incorporates this information into its estimates of rate structure savings. Third, in implementing rate structures, BC Hydro provides information to customers to educate them on the rate structure and how they can respond to it and achieve bill savings. Finally, BC Hydro's demand-side management programs are designed to complement and support the rate structure and customer response to price signals.

If rate structure savings are lower than planned, BC Hydro can take the following actions:

- Redesign rate structures;
- Increase customer communication and support effort related to rate structures; and
- Expand other demand-side management initiatives to achieve additional savings if needed and cost-effective.

4.2.3 Program Risks and Mitigation

The principal risks as they relate to programs are:

- Participation Risk: demand-side management programs do not achieve the expected level of participation;

- Savings Risk: The savings per participant in demand-side management programs is lower than expected; and
- Cost Risk: Program costs are higher than expected.

To minimize the risk of lower participation than planned, demand-side management programs are designed to address barriers to energy efficiency and elicit customer participation using information from BC Hydro customers, trade allies and other jurisdictions. Conservation and Energy Management also recognizes that changing customer expectations over time will mean that programs may need to adapt to achieve desired participation levels. Conservation and Energy Management also undertakes market and technical research into current and future demand-side management opportunities to develop the most effective initiative designs. In addition, conservation rate structures complement programs.

Programs also face a risk of delivering lower savings per participant than planned. This risk is mitigated by using a variety of sources on unit savings to forecast overall program savings, including market research, technical reviews of projects, measurement and verification results and program evaluations. In addition, if measurement and verification results indicate that less energy savings were received than the amount stated in the demand-side management incentive agreement, the incentive amount can be adjusted per the incentive agreement so that BC Hydro is not overpaying for reduced energy savings. In these agreements, BC Hydro has a mechanism to ensure that it is paying for verified savings. This linkage between measurement and verification results and incentive payments is not common among demand-side management programs in other jurisdictions.

If demand-side management program electricity savings or budget are not tracking to plan, BC Hydro can respond by:

- Modifying program advertising;
- Modifying the program application process or eligibility criteria;
- Modifying program incentives;
- Modifying the program approach; and

- Revising the list of qualifying products.

The flexibility of programs also provides a greater ability to adjust programs in response to savings shortfalls in other demand-side management tools. These mitigation measures, however, have limitations in the event a large, complex project (such as thermal-mechanical pulp) is delayed or cancelled.

4.2.4 Portfolio Risks and Mitigation

The portfolio risks are managed through the flexibility of adjusting the demand-side management plan as required based on the ongoing monitoring of plan performance. For instance, if performance falls below plan in one sector or initiative, Conservation and Energy Management can reallocate costs or resources between initiatives or sectors to improve the performance.

4.3 Electricity Savings Confirmation

Reliably estimating demand-side management electricity savings, upon which financial decisions are made and progress towards targets are reported, is a key aspect of managing demand-side management performance. Depending on the demand-side management initiative, there can be up to four distinct areas of activity that ultimately contribute to the confirmation of demand-side management savings estimates: technical review, site inspection, measurement and verification, and evaluation. Results from each area are used in project and contract management to ensure that BC Hydro receives the expected project benefits for its incentive payments. Conservation and Energy Management is selective in the use of these processes, and focuses its efforts where warranted to improve the accuracy of savings estimates and reduce exposure to the risks described above.

- **Technical Review:** The purpose of the technical review is to ensure that energy savings are adequately described and supported by appropriate engineering calculations. For residential initiatives and prescriptive measures in the commercial and industrial customer sectors, the technical review is typically used to assess energy savings as part of the program design. For the commercial and industrial sectors, the technical review is done before and shortly after a measure is implemented, and ensures that the following elements are in place for a specific measure: a description of the measure; a defined and quantified baseline condition; a system boundary; explicit engineering calculations of the electricity savings achieved; and documented and referenced assumptions that align with common industry standards and practices;

- **Site Inspection:** The inspection is conducted to confirm that the project is complete, was implemented as agreed with BC Hydro and to confirm or adjust the variables and assumptions used to estimate the energy savings during the technical review. Site inspection is performed on a sample of projects;
- **Measurement and Verification:** This is the quantification of individual project energy savings through analysis of actual project operating and performance data. On-site measurement and data collection, utility billing data and computer modelling may be used to analyze and confirm the energy and demand savings from individual projects. Conservation and Energy Management conducts measurement and verification on a sample of customer projects. At the initiative level, measurement and verification analysis is used to measure and confirm program assumptions such as hours of equipment usage or product specifications. In carrying out its measurement and verification work, Conservation and Energy Management is guided by an internationally accepted protocol for measurement and verification of energy saving projects; and
- **Evaluation:** Conservation and Energy Management evaluates demand-side management initiatives through studies and activities aimed at determining its effects. Evaluations use measurement and verification results and may also trigger additional measurement and verification activities to confirm technical assumptions on projects. In carrying out its evaluation activities, Conservation and Energy Management is guided by the California Evaluation Framework and Protocols and the U.S. Department of Energy Uniform Methods Project Protocols, which are generally regarded as the leading protocols for demand-side management evaluation in North America. Evaluation reports are reviewed by external demand-side management evaluation advisors and reviewed and approved by a cross-BC Hydro committee. This ensures the evaluation reports align with industry best practice. BC Hydro also files an annual report to the British Columbia Utilities Commission with Executive Summaries of the previous year's evaluation reports. Conservation and Energy Management periodically

updates reported demand-side management savings to reflect new information stemming from the steps outlined above, which provides a comprehensive process for estimating demand-side management savings.

5 Residential Sector Programs

5.1 Residential Sector Overview

BC Hydro's residential sector has over 1.7 million customer accounts and sales to this sector total approximately 17,350 GWh annually[13], representing 35 per cent of BC Hydro's annual load. The average residential account consumes about 10,000 kWh annually, although this varies widely with the type of home and the type of heating fuel used.

5.1.1 Residential Sector Strategic Approach

Programs are offered focusing on specific customer segments as well as specific products. These programs are designed to take into consideration: the opportunities identified in research, through program benchmarking, and feedback from the marketplace; reducing the barriers that exist for customers to adopt those technologies or behavioural changes; and finally partnerships that can be leveraged to successfully bring these programs to market.

Initiatives implemented to date have typically been through partnerships with both the private and public sectors, to ensure market impact. Rather than competing with existing channels, BC Hydro has leveraged the BC Hydro Power Smart brand and customer relationships in order to move customers towards existing channels that offer opportunities for electricity savings, while improving the ability of those channels to better meet our customers' needs. This approach has ensured a more sustainable impact on the channels that we are working through than could be achieved if BC Hydro sought to control a channel more directly. BC Hydro has leveraged additional funds from channel partners and other government sources, thereby improving the impact and cost effectiveness of different program offers.

BC Hydro has focused over the past several years on customers' evolving needs and how programs can be tailored or positioned to best resonate with people. The use of customer

[13] Sales by Revenue, April 2018.

analytics to better target customers who are more likely to participate in certain offers helps to ensure that the right message, reaches the right customer, via the right channel. Messaging will typically drive customers to the BC Hydro website where customers can find more detailed information and/or apply for programs.

Finally, these approaches and key partnerships can be used in the development of offers beyond conservation, such as capacity focused, low-carbon electrification[14], and the connected home. Many of the existing programs can be platforms for delivering these new offers to our customers and they also support codes and standards implementation by providing market intelligence about existing products and working to ensure that products are available and accepted by British Columbians prior to introducing a code or standard, thereby minimizing pushback from industry and the public.

5.2 Low Income Program

5.2.1 Overview

The Low Income program helps BC Hydro's lower income customers to reduce their energy consumption and lower their BC Hydro bills with an encompassing and free energy efficiency program offer. The Low Income program addresses the capital, awareness, education and other barriers that often prevent our lower income customers from improving the efficiency of their home. Low income households in both owner-occupied and rental accommodations are eligible. There are two key components to this program, seeking to address both the breadth and depth of our lower income customers' needs: Energy Savings Kits and the Energy Conservation Assistance Program.

Over fiscal 2020 to fiscal 2022, the Low Income program has increased expenditures to help BC Hydro's lower income customers with electricity bill affordability (see section 5.2.2 for more details). The program has had participation from Indigenous customers over much of the life of the program, and based on that experience and a trial in fiscal 2017 to fiscal 2018, a new approach to working with these communities will be introduced to better meet their needs.

[14] Low-carbon electrification is not included in this plan, incremental internal expenditure approval will be sought separately.

Since 2010, BC Hydro has partnered with FortisBC Energy Inc. to reduce costs and improve the effectiveness of providing this program to low income customers across the province. FortisBC Inc. is running a similar program modelled after the BC Hydro Low Income program in their electric territory. BC Hydro is also coordinating with Pacific Northern Gas in their service territory on delivery of the Low Income program.

Annual Plan	**$ million**	**GWh/yr**
F2020	5.8	9
F2021	6.9	9
F2022	7.8	9
Target Market	Lower Income Residential Customers (Statistics Canada's Low Income Cut-off threshold +30 per cent). Both owner occupied and renters.	
Key Components	Energy Saving Kits	
	Energy Conservation Assistance Program	
	Indigenous Customers Offer - New	
Cost Effectiveness	**Utility Cost (Market Price at $30 per MWh)**	**Modified Total Resource Cost (LRMC at $105 per MWh)**
Net Levelized Cost ($/MWh)	36	(29)
Net Present Value ($M)	(1)	35
Benefit Cost Ratios	0.9	3.5

Customer Benefits	**Industry Benefits**	**BC Hydro & Shareholder Benefits**
• Utility bill savings • Provides free access to energy efficient technologies and home improvements • Improved home comfort and safety • Increased knowledge of ways to lower energy bills • Supports owners and renters	• Supports B.C.'s home performance retrofit industry	• Generates positive earned media and customer satisfaction • Meet the Demand-Side Measures Regulation • Supports relationships with Indigenous communities • Supports the FortisBC Partnership

5.2.2 Description

	Detailed Description
Energy Saving Kits	The Energy Savings Kit is a package of basic energy saving measures provided at no charge that can be installed by most homeowners or tenants with limited or basic tools. Energy Savings Kits contain lighting-related products, water saving products (e.g., faucet aerators and a high performance showerhead), heat-loss products (e.g., draft proofing material, and window film) and general energy savings tips and brochures. In 2019, the program is expanding to provide participants window film on an annual basis at no cost. Window film is only used for one heating season and then removed. In addition, Energy Saving Kits will be provided at pre-qualified events (e.g., foodbanks, and Indigenous community events) and will not require a BC Hydro account number to receive a kit. Over the past two years, approximately 35 per cent of participants have been renters or tenants.
Energy Conservation Assistance Program	The Energy Conservation Assistance Program provides eligible BC Hydro low income Residential customers with a home evaluation, installation of energy saving products and education on what customers can do around their homes to save energy. There is no charge for the products or services provide through the program. Some of the energy saving products that may be installed include energy saving light bulbs, low-flow showerheads and faucet aerators, pipe wrap, draft proofing (e.g., door sweeps), an Energy Star refrigerator, a high-efficiency gas furnace (in conjunction with FortisBC Energy Inc.), and insulation for attics, walls and crawlspaces. Program criteria are being revised to enable more homes to receive weatherization upgrades and expanding the refrigerator replacement offer to apartments run by non-profits and co-op housing providers. Over the past two years, approximately 75 per cent of participants have been renters or tenants.
Indigenous Customers Offer	For customers on the integrated electricity system the Indigenous Customers offer, planned for late fiscal 2019, will partner with communities to support and encourage them to include energy efficiency measures when undertaking home renovations within their communities through their own channels. The program will provide funding for weatherization measures through a rebate model which will enable communities to combine multiple funding sources. The offer will also include a training component for community members on best practices for installing insulation for interested communities. For communities in the non-integrated system areas of the province, BC Hydro will be launching the new Non-integrated Areas program. A final component of Indigenous communities policy support is provided through BC Hydro’s Codes and Standards activities, these will work in conjunction with both customer offers described here.

5.3 Retail Program

5.3.1 Overview

BC Hydro seeks to influence our residential customers to purchase more energy efficient products, and leverages the retail channel to activate these transactions. The Retail

Program aims to advance the adoption of more energy efficient products by working with market partners to have the energy efficient products available on store shelves throughout B.C. at affordable price points, supported by knowledgeable sales staff.

The Retail program reaches large numbers of customers in a channel that they can utilize many times in a year, while offering a variety of low cost options or upgrades for residential customers (owners and renters) to become more energy efficient. Due to the partnerships with retailers (e.g., Home Depot, BestBuy) and manufacturers (e.g., Philips, Samsung), this program is able to leverage additional exposure in the form of flyer advertising, e-newsletters, websites and instore promotion, additional customer sales support from retail sales staff, and further discounting on products funded through manufacturers.

Key manufacturer and retailer channel partners are targeted to influence products stocked, promoted and how they are positioned. These partners represent the largest market share and widest exposure across the province. The program leverages the potential for low-cost and far-reaching public exposure through partner's flyers, promotions and space in-store. Joint utility and municipality collaboration allows for increased rebate offers to customers, operational efficiencies and enhanced customer experience. These partnerships, channels to market, and opportunities to leverage consumer engagement enable a platform for new offers such as connected home technology or demand response capable devices. The program is also designed to increase the market penetration of energy efficient products to set the stage for collaborating with governments and standards agencies to help push changes to energy efficient regulation.

Annual Plan	$ million	GWh/yr
F2020	2.1	6
F2021	2.1	5
F2022	2.2	5
Target Market	Residential customers who purchase product through the retail channel. Can include both owner occupied and renters (for lower cost product investments). Key partnerships are with retailers like Best Buy, Home Depot, Costco and a variety of appliance, lighting, electronics, and home improvement product manufacturers	
Key Components	Channel partnerships	
	Product Incentives	
	Advertising and promotions (often provided by the retailer/manufacturer partners)	
Cost Effectiveness	**Utility Cost (Market Price at $30 per MWh)**	**Modified Total Resource Cost (LRMC at $105 per MWh)**
Net Levelized Cost ($/MWh)	2	(6)
Net Present Value ($M)	6	19
Benefit Cost Ratios	2.0	6.0

Customer Benefits	Channel Partner Benefits	BC Hydro & Shareholder Benefits
• Better accessibility and availability to products • Reduced cost to purchase • Utility bill savings • Other non-energy benefits depending on the appliance/product (e.g., extra features, water savings etc.) • Easy to participate with low cost options for renters and home owners • Education and awareness • Customer satisfaction	• Increase sales with incentives and in-store execution • Campaign promotions and fulfilment educates their customers and drives traffic to their stores • Leverage other program initiatives • Partner satisfaction	• Positive public exposure in partner owned channels by leveraging long-standing relationships • Customer and channel partner satisfaction • Established channels to market can ease the expansion of any future customer offers • Supports Codes and Standards

5.3.2 Description

	Detailed Description
Channel partnerships	The program works with select retailers, manufacturers and supporting partners in order to collaborate on addressing market barriers to purchasing energy efficient products. Aligning with retailers who represent the largest market share, BC Hydro maximizes its resources and its partners' resources to increase participation, awareness and ultimately drive adoption of energy efficient products. Complementary manufacturing partnerships are chosen to further influence the campaign offers, driving participation, awareness and adoption. BC Hydro partners with FortisBC to reduce program costs, increase customer incentives and make it easy for customers to participate. FortisBC leverages the negotiations BC Hydro has developed with its channel partners. BC Hydro runs campaigns through the year that target various end-use categories. This approach to campaign management provides operational efficiencies while maximizing the time that offers are in market and available to assist customers. Partnering with local governments, BC Hydro is able to leverage municipal funding available to reduce water use and GHGs to increase customer incentives, drive participation, and make it easy for customers to do business with us.
Incentives	The program provides different incentives as needed, through various means designed to elicit the best market response. Downstream incentives are offered to residential customers to reduce the cost to purchase energy efficient products, driving awareness and partner engagement. The program provides mid-stream incentives where appropriate to retailers, to position, promote and drive sales of energy efficient products.
Advertising and Promotion	Typically twice a year, BC Hydro manages campaigns and offers at strategic retailers with specific manufacturers. By supporting channel partners through advertising, promotions and program collateral, the program leverages partner flyer exposure and other promotional channels as well as additional incentives from retailers and manufacturers to customers. The exposure that retail partners provide BC Hydro helps to stimulate interest and excitement amongst our customers in ways that we would not be able to achieve on our own. In store events also provide BC Hydro an opportunity to educate customers on energy efficient products and behaviors.

5.4 Home Renovation Rebate

5.4.1 Overview

The Home Renovation Rebate Program focuses on customers with electric heat, who typically have the highest electric bills as heating is normally 50 per cent of a home's energy consumption. The program seeks to motivate these customers to undertake energy efficiency upgrades to their existing homes, primarily focused on lowering their space heating load and hence making their electric bills more affordable. The program promotes upgrades to building envelopes (insulation, windows, draft proofing), space and hot water heating systems, and ventilation, with a combination of rebates for single and multi-upgrade improvements. The Program is jointly administered with FortisBC Energy Inc. and FortisBC Inc., allowing customers to access a single offer regardless of whether their homes are electric or gas heated. The Home Renovation Rebate budget was augmented to increase incentives for some measures (e.g., insulation) as well as expand the number of measures (e.g., heat pumps) for electrically heated customers to improve the affordability of their BC Hydro bills.

In addition to direct incentives, the program communications are aimed at program awareness and participation, and educating consumers on energy efficient home renovations. The program works with contractors, providing program details, training, sales support and recommendations on installation best practices in home energy retrofits to improve the availability and quality of home energy retrofit services in B.C. The program can be a platform for new offers that require expert installation such as demand response capable water heaters, whole home automation/connected home.

Annual Plan	**$ million**	**GWh/yr**
F2020	4.2	8
F2021	4.4	8
F2022	4.6	9
Target Market	Residential customers primarily with electric heating (owner and renter occupied buildings)	
Key Components	Rebates for building envelope improvements, heating systems, ventilation upgrades, and a multi-measure bonus.	
	Coordinated application and partner rebates – FortisBC, Province of BC, Municipalities (in development phase)	
Cost Effectiveness	**Utility Cost (Market Price at $30 per MWh)**	**Modified Total Resource Cost (LRMC at $105 per MWh)**
Net Levelized Cost ($/MWh)	(8)	47
Net Present Value ($M)	15	35
Benefit Cost Ratios	2.3	1.9

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
• Utility bill savings • Improved home comfort • Health, safety, comfort, and building durability as well as other non-energy benefits • Reduced maintenance • Easy access to coordinated utility program offers (one-stop-rebate shop)	• Increased sales of efficient products	• Support electrically heated customers to lower their bills • Align with Provincial interests • Flexible program platform can be leveraged for additional partners and more complex future initiatives including demand response and low-carbon electrification

5.4.2 Description

	Detailed Description
Program Rebates	The incentives are designed to reduce the customer's upfront cost of installing more efficient measures and technologies. Incentives also support consumer awareness of energy efficient technologies.
Partnerships and Coordination	The Program partners with FortisBC to offer a coordinated administrative and application platform for multiple home energy rebates. In addition, in fiscal 2019 the program is expanding to include rebate partnerships with the Province of B.C. and several municipal governments to provide additional rebates for participants by leveraging the existing program platform. This approach has provided internal efficiencies and improved the customer experience in finding and accessing related program rebates.

5.5 Non-Integrated Areas

5.5.1 Overview

This plan includes a deeper focus on energy efficiency activities and offers for customers living in non-integrated areas of BC Hydro's service territory. Reduction of consumption in these areas reduces high-cost electricity production as well as BC Hydro's GHG emissions from diesel generation. The majority of the activities are for residential customers, but there is also a small commercial component. This offer was informed by pilot work conducted in fiscal 2017 to fiscal 2019.

BC Hydro provides electricity to customers in Non-Integrated Areas (**NIA**) through a combination of diesel generating stations owned and managed by BC Hydro and small hydro plants (owned by BC Hydro or Independent Power Producers). NIA customers – including Indigenous customers – struggle to understand and pay their bills, and are often subject to higher bills as a result of poor housing construction and maintenance practices and severe weather conditions in some remote areas.

In our recent regulatory filings (Fiscal 2017 to Fiscal 2019 Revenue Requirements Application), interveners expressed a clear interest in and need for additional BC Hydro efforts to assist NIA communities in implementing DSM activities. Conservation and Energy Management has reflected this feedback in its plan by moving from pilot initiatives to a dedicated program for NIA communities.

This work stream includes new residential and commercial program offers to assist NIA customers in saving electricity, reducing utility bills and improving home comfort, while helping NIA communities to reduce their reliance on diesel generation, thereby reducing GHG emissions.

Annual Plan	**$ million**	**GWh/yr**
F2020	1.2	0
F2021	1.4	1
F2022	1.5	1
Target Market	Indigenous and Non-Indigenous customers living in one of BC Hydro's Non-Integrated communities	
Key Components	Residential rebates	
	Commercial Direct Install	
	Community Support	
Cost Effectiveness	**Utility Cost**	**Modified Total Resource Cost**
Net Levelized Cost ($/MWh)	175	117
Net Present Value ($M)	3	4
Benefit Cost Ratios	1.8	2.2

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
• Increased energy literacy • Improved home comfort and other non-energy benefits • Utility bill savings • Health, safety, and building durability • Reduced maintenance • Local economic development opportunities • Reduced reliance on diesel • Air quality and climate benefits (GHG reductions)	• Small local service providers and/or community members will be utilized where feasible • Local economic development opportunities	• Strengthened relationships and partnerships with Indigenous communities • Reputational benefits • Reduced costs of service • Energy savings and GHG reductions

5.5.2 Description

	Detailed Description
Residential Rebates	Residential opportunity assessments and energy conservation measures (**ECMs**) delivered by Indigenous governments (Bands, Tribal Councils), using local community members and contractors to perform the work. Training will be provided at different points through the project lifecycle to assist Indigenous governments in advancing home energy upgrades and accessing rebates (e.g., how to assess energy saving opportunities in the home, how to install basic energy savings measures, how to prioritize and plan for additional retrofit opportunities, best practices in air sealing and insulation for contractors/trades). ECMs include basic measures such as LED lighting, faucet aerators, basic draft proofing materials (weather-stripping, caulking, outlet gaskets. window film), pipe wrap, dryer rack, CO monitors and smart strips, as well as deeper measures such as windows and doors, insulation, advanced air sealing, ventilation systems, heat pumps and programmable thermostats.
Commercial Direct Install	Basic commercial ECMs (e.g., lighting and some refrigeration measures) are installed in commercial and community/Band-owned buildings by Alliance-approved vendors.
Community Support	Financial and technical support to Indigenous governments

5.6 Residential Energy Management Activities

5.6.1 Overview

The objective of the Residential Energy Management Activities is to provide information and tools that assist customers to optimize their energy use. This is accomplished through support of BC Hydro's residential Demand-Side Management programs, rates, and codes and standards efforts in achieving their respective energy management and market transformation objectives. The three key elements of the energy management activities include a behavior program, industry support, and access to energy data.

The centre-piece of the Residential Energy Management Activities is the Behavioural program designed to encourage residential customers to adopt more energy conscious behaviours and practices that lead to electricity savings and lower bills. The program relies on well-established behavioural change methods such as Feedback and Challenges. Customers don't need to invest in products, they only need to change how they use the products they already own.

Industry support is an important feature to provide customers with access to trained and qualified trade allies/supply-chain partners who can assist them in understanding their energy management options, providing an assessment, and completing their projects/making their purchases. While ensuring quality performance, these partnerships also lead to market push, ultimately resulting in the increased penetration of energy-efficient technologies and energy management solutions.

Providing feedback and energy data is a powerful tactic that results in increased awareness and insights, which in turn lead to adjustments in the operation of a household to optimize energy use. Detailed in-home consumption feedback from smart meter data is offered to all customers through the Energy Visualization Portal (**EVP**) on the BC Hydro website and for more engaged customers in near real-time via home energy monitors. The EVP presents customers with different and customizable views of their electricity consumption patterns (hourly, daily, weekly, monthly, and yearly), as well as comparisons to previous periods, similar homes nearby and average temperatures. Users can also view consumption forecasts, download their data and subscribe to various alerts. Through these different analytics tools in the EVP, the Behavioural program increases awareness and understanding of consumption patterns among BC Hydro's customers.

Annual Plan	$ million	GWh/yr
F2020	5.0	13
F2021	4.9	13
F2022	5.0	12
Target Market	All Residential customers who require assistance to make the best decisions around energy management for their household. Can be utilized by owners and renters	
Key Components	Detailed consumption feedback	
	Energy reduction challenges with membership	
	Energy Management Coaching and Home Assessments	
	BC Hydro Alliance of Energy Professionals (across all sectors)	
	External Workforce Capability Building (across all sectors)	
	Customer Information Support	

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
• Personal, relevant and actionable recommendations and tips • Proactive engagement and guidance from BC Hydro on energy management issues • Opportunity to earn rewards through successful Team Power Smart Challenges • Utility bill savings • Assistance in accessing qualified products and industry expertise • Increased availability of products and expertise, as well as quality within industry • Energy management information, advice, and program access support • Often low cost/ no cost advice for both home owners and renters	• Contests, promotions, and offers driving customers to products and channels that help customers manage their energy use • Promotion of third- party tools that support energy data such as in-home monitors and future mobile applications • Training and support on available BC Hydro programs, technologies, and changes codes and standards • Partners can expand their suite of products and service offerings to customer	• Utilizes smart meter data by presenting customers with rich and timely information • Provides a highly engaged and accessible group of customers for testing new products, services and programs and to act as advocates for energy management and as ambassadors for BC Hydro • Foundational platform from which to launch future new offers • The trade ally network effectively sells and promotes BC Hydro programs to customers • Market and technical insights including technology adoption, new customer opportunities and feedback on Demand-Side Management program effectiveness • Ensuring there are well training trades helps to reduce BC Hydro's risk of poor workmanship and/or unhappy customers • Communication channel with industry, and insight into various firms expertise • The extensive relationships with industry allows for the introduction of new services and solutions in the future.

5.6.2 Description

	Detailed Description
Detailed Energy consumption feedback	Customers receive access to tools that allow them to better understand their household electricity consumption. When they create a MyHydro profile and link their account they can log into BC Hydro's customer portal with their email address and password to access graphs with detailed consumption feedback from their smart meters. These graphs allow them to analyze their hourly, daily, weekly, monthly and yearly consumption patterns. Comparing their consumption to the previous year and to similar homes allows customers to assess whether there are any opportunities to reduce their consumption. They can also see the impact of the outside temperature on their electricity consumption and subscribe to a free email reminder service to help them log-in on a frequent basis. These analytics tools increase customers' awareness of their electricity consumption and it empowers them to look for opportunities to take action to reduce their bill. Home Energy Monitors connect wirelessly to a customer's smart meter and provide real-time energy information from SMI data. These devices are constantly evolving and BC Hydro and Powertech work closely with industry leaders to ensure system compatibility and a seamless and positive customer experience. BC Hydro will start a trial of Home Energy Reports: select customers will receive a print report with consumption graphs and other insights about their electricity consumption, as well as tailored recommendations and actionable tips. The use of Home Energy Reports is a tried and tested behavioural strategy to engage hard-to-reach target segments. It is already successfully deployed by around 100 North American utilities.
Energy Challenges and membership through Team Power Smart	Customers can become a member of Team Power Smart. This provides them several benefits, including the opportunity to enter into a Challenge to reduce their household electricity consumption by 10 per cent or more below the previous year's consumption. If they are successful they will receive a $50-bill credit. A Maintenance Challenge is also available; if they stay at or below the lower consumption level that was accomplished during their successful Reduction Challenge they will receive a $25 bonus. Challenge participants receive proactive reminders from BC Hydro to keep them engaged, status updates on how they are progressing with their Challenge and tips and advice on strategies and actions that can assist them in reaching their goal. Team Power Smart members can participate in members-only contests and benefit from offers; they also receive tailored communications by mail and email including progress updates, practical tips, and motivational stories, etc. This offer benefits both home owners and renters.

	Detailed Description
Energy Management Coaching and Home Assessments	Energy coaches provide personalized support and resources to assist customers in undertaking home energy management upgrades. Coaching can range from advice delivered by phone to personal support for implementing upgrades (such as helping review contractor bids). The program is building on energy coaching related services that were trialed in fiscal 2018 in partnership with six municipalities and the Government of B.C, which includes a coaching hotline and in-person coaching services. Home Energy Assessments (or home energy audits) provide a personalized overview of home energy use and energy saving opportunities. A comprehensive in-home assessment and modelling of home energy use completed by a licensed Energy Advisor is required to access the performance path program bonus for the Home Renovation Rebate program and serves as an important energy management support tool.
BC Hydro Alliance of Energy Professionals	The BC Hydro Alliance of Energy Professionals is a network of contractors, consulting engineers, manufacturers, distributors, retailers, and registered experts that will promote the use of energy management and efficiency solutions to our customers. BC Hydro leverages the Alliance members' ability to sell and promote energy efficient products, services and programs to our customers within the context of demand-side management programs which is a cost-effective approach to minimize program marketing expenditures. BC Hydro delivers training to Alliance members to ensure they are educated on energy management and trained on the details of the available BC Hydro programs. This goal is achieved in part through partnerships with associations for development and delivery of courses and workshops. The BC Hydro Alliance of Energy Professionals also enables Conservation and Energy Management to monitor and assess the quality of work that customers receive from Alliance members, and take remedial action if deficiencies are identified. With constant turnover in the distributor and retail channel, BC Hydro recognizes the need for substantial effort in regular training and education activities with sales associates. A coordinated approach with channel partners allows BC Hydro to take advantage of existing training infrastructure including product road shows, monthly meetings and online training to reach as many sales associates as possible around the province. This approach allows for sales associates to act as ambassadors for the program, as they educate and assist customers and drive sales of energy efficient products.
External Workforce Capability Training	A critical success factor for the Demand-Side Management Plan is that there is an available and accessible qualified installation contractors in place in B.C. BC Hydro plays an important role in identifying and filling skill gaps in the workforce by supporting the development of the professional home energy performance industry in B.C. by working with partners to support third party industry trades groups (e.g., the Home Performance Stakeholder Council), professional contractor training, and development and implementation of contractor accreditation and certification programs.
Customer Energy Information Support	BC Hydro assists our customers to resolve their energy related inquiries and become more educated on how to access our programs and energy saving opportunities. The Customer Support Centre – call centre provides a first call/email option for our customers to find out more about their specific energy inquiries. Additionally they provide, through the Business Help Desk (a group of specialized agents), a channel of support for specific energy management program inquiries.

6 Commercial Sector Programs

6.1 Commercial Sector Overview

BC Hydro's commercial sector, including small and medium businesses to key account managed large commercial customers, has over 95,000[15] customer accounts and sales to this sector total 15,700 GWh annually. The average commercial account consumes 99,000 kWh[16] annually, although there is a wide distribution of consumption among the various customer segments.

6.1.1 Sector Strategic Approach

The Commercial sector provides support and initiatives for customers to address their diverse needs and barriers. Programs are designed to take into consideration the technical and customer segment opportunities, reducing the barriers that exist for customers to adopt those technologies or operational changes, and finally developing partnerships that can be leveraged to successfully bring these programs to market. The suite of offers helps customers identify opportunities, adjust their business operations, and implement capital projects. This approach will achieve cost savings, keep rates low, and support a trusted energy advisor relationship with customers and BC Hydro. All the commercial programs have been designed as flexible platforms that can add new offers and services as customer needs evolve.

For the F2020-F2022 Demand-Side Management Plan, Commercial programs will continue to focus on delivering a variety of solutions that will help customers achieve energy savings, increase their energy literacy, and make it easier to do business with us. This includes:

- Providing customers with energy data information such as having access to tools, graphs, charts and reports that for instance identify unusual building consumption and changes in a building's energy performance;
- Supporting a strategic energy management approach to integrating energy efficiency considerations into ongoing customer business practices and company culture;

[15] Sales by Revenue, April 2018.
[16] 2014 Commercial End-Use Study, page 298.

- Focusing support to customers that require our help the most, such as small and medium businesses and Healthcare, Education, and Government sectors, while still ensuring all customers have an opportunity to participate;
- Raising awareness of the opportunities that exist for customers to save on their electricity bill and integrate best practices in their operations and buildings;
- Working with the BC Hydro Alliance of Energy Professionals who assist business customers find opportunities to save energy, install energy-efficient products, and ensure product availability;
- Providing customers with significant support through training, technical expertise, financing options, and funding to optimize the energy consumption in their buildings; and
- Support growth in market capability by continuing to support industry-driven efforts by creating the appropriate tools and resources and educational opportunities to deliver sustained, high quality services to the marketplace. These efforts help to drive market transformation and assist in the adoption and compliance of building codes.

6.2 Leaders in Energy Management – Commercial (LEM-C)

6.2.1 Overview

The Leaders in Energy Management – Commercial (**LEM-C**) program provides energy efficiency solutions to assist customers with their energy efficiency projects. The program is intricately linked to the Commercial Energy Management Activities to help customers overcome the management and business barriers to energy efficiency. This approach will achieve cost savings, helps with affordability and supports a trusted relationship with customers. This program targets BC Hydro’s commercial segment, including small and medium business to key account managed large commercial customers.

Given the design of the program and the relationship with the customers, it provides an important base to allow the addition of new initiatives as opportunities evolve in areas such as capacity focused DSM offers.

Annual Plan	**$M**	**GWh/yr**
F2020	9.0	51
F2021	9.1	47
F2022	9.2	39
Target Market	Public Sector (Healthcare, Education, Government) and Commercial customers. Small and Medium Business are also a key target.	
Key Components	Project Energy Study	
	Project Implementation Funding	
	Social Housing Retrofit Support Offer	
	BC Hydro Technical Expertise	
Cost Effectiveness	**Utility Cost (Market Price at $30 per MWh)**	**Modified Total Resource Cost (LRMC at $105 per MWh)**
Net Levelized Cost ($/MWh)	4	(39)
Net Present Value ($M)	35	195
Benefit Cost Ratios	2.5	4.0

Customer Benefits	**Industry Benefits**	**BC Hydro & Shareholder Benefits**
• Make smart choices with their power: Providing tools and new technologies, allowing customers to reap the benefits of cost savings. • Bill savings: Reduce customers' electrical operating costs. • Improve corporate culture • Remove financial barrier: Incentives to help overcome customers financial hurdle rates and lower project payback period to an acceptable level. • Other non-energy benefits depending on the end-use/project (e.g., maintenance, enhanced building value etc.) • Supports customers that need assistance in the public sector and small and medium sized businesses	• Support advancement in technology: Increase market demand that supports research and development towards more efficient end uses.	• Demonstrate commitment and support for helping customers to more easily do business with us: Seen as a trusted and credible partner to support customers and industry achieve their goals. • Foundational platform for capacity focused DSM • Retain flexibility: The offer can be adjusted quickly to changing internal and external demands by scaling up or down, adding funding partners or new program measures. • Support towards market transformation: Emphasis on market transformation and education of key stakeholders by providing the right tools and resources. • Support customer service: Ability to integrate customer strategy initiatives as necessary to ensure optimized delivery of offers.

6.2.2 Description

	Detailed Description
Project Energy Study	The Project Energy Study provides customers with detailed technical information, quantified energy information and expected implementation costs for specific projects. The study can be used to determine the most effective energy conservation measure for implementation that best fits the customer's needs. Energy Study eligibility criteria is only available to organizations with BC Hydro sponsored Energy Managers and Energy Manager Associates.
Project Implementation Funding	Project Implementation funding is available to help customers reduce the capital cost of implementing the identified measures. Upon review of the study and subject to adherence to program rules and passing economic cost tests, customers are offered a capital incentive agreement for signature. In addition, Business Energy Saving Incentives is an online process for simple one-to-one retrofits covering a wide range of technologies that is supporting all sizes of customers, particularly small and medium sized businesses. Project Implementation Funding eligibility criteria is only available to organizations with BC Hydro sponsored Energy Managers and Energy Manager Associates.
Social Housing Retrofit Support Offer	Newly introduced for fiscal 2019 is the Social Housing Retrofit Support Offer for Multi-Unit Residential that provides an opportunity for qualifying social housing providers (e.g., BC Housing, and the B.C. Non-Profit Housing Authority) to minimize their operating costs and improve whole building performance of their facilities through the more efficient use of natural gas and electricity. This offer is a partnership between FortisBC Energy Inc., FortisBC Inc., BC Hydro and the Government of B.C. (through Efficiency B.C.) and is offered throughout the British Columbia service territories of the utilities. Customers are allowed to utilize any of the four offers below: Energy study funding to review the potential energy conservation measures. Implementation support that provides engineering design, tendering and project management Rebates for upgrading eligible technologies for lighting, HVAC and commercial kitchen Rebates for low-carbon electrification opportunities
BC Hydro Technical Expertise	BC Hydro will provide project specific internal technical assistance and support to the customer throughout a project to allow for an integrated customer experience. Tools, such as project calculators, are also created to further support the customer that allows for a cost effective support model.

6.3 New Construction Program

6.3.1 Overview

The Commercial New Construction program provides industry training, customer coaching and financial support for the design and implementation of new high performing buildings. The program sets the stage for changes to energy efficiency requirements in Part 3 of the B.C. Building Code. This part of the B.C. Building Code covers large and complex buildings, such as hospitals, schools, and high-rise condo buildings. The activities of the program assist in the transition to more efficient building codes, but to be conservative the program does not take any benefit from the attribution of those codes saving.

The Province has committed to taking incremental steps to increase energy-efficiency requirements in the BC Building Code to make buildings net-zero energy ready by 2032. The BC Energy Step Code-part of the BC Building Code-supports that effort and was enacted in April 2017. It is anticipated that by 2022, there will be widespread voluntary adoption of the BC Energy Step Code by municipalities, and that this will signal the wind down of this phase of the program.

This program will then transition to a codes and standards strategy to most effectively sustain the drive towards more efficient buildings, freeing up resources to potentially focus on providing broader offers to the new construction sector such as low-carbon electrification,[17] demand response capable technologies and advanced connected building systems.

The Commercial New Construction program continues to provide a foundation of energy efficiency support and initiatives for customers, while building capability to transform the new construction market, leveraging new technology capabilities in the marketplace, and adapting to changing customer needs.

The program's key objective is to provide technical expertise and funding in the form of design and modelling support, energy studies, personalized coaching, and advanced training for the design and implementation of cost-effective energy efficiency measures and building systems that exceed building code requirements.

The Commercial New Construction program is also well established to assist in improving compliance levels with the BC Building Code and the Vancouver Building Bylaw given BC Hydro's expertise and interaction with different industry players. The program is playing a role to increase the compliance level of these codes by focusing on industry education and training, building information data sharing and including program requirements for all Whole

[17] Low-carbon electrification is not included in this plan; incremental internal expenditure approval will be sought separately.

Building Design projects to be physically inspected. By continuing to advance aggressive energy efficient building requirements and seizing the "one-time" opportunity to incorporate those measures into design and construction of new commercial buildings, the program also provides both support for the introduction of ongoing more aggressive building codes and the compliance of current codes and standards.

Annual Plan	**$ million**	**GWh/yr**
F2020	3.7	8
F2021	2.4	5
F2022	2.0	5
Target Market	New Construction projects focusing on Healthcare, Education, and Government, as well as support for other Commercial/Multi-unit Residential developers/owners.	
Key Components	Pre-engagement: Design team kick off meeting	
	Energy Study Proposal	
	Energy Study	
	Project Implementation Funding	
	BC Hydro Technical Expertise	
Cost Effectiveness	**Utility Cost (Market Price at $30 per MWh)**	**Modified Total Resource Cost (LRMC at $105 per MWh)**
Net Levelized Cost ($/MWh)	16	17
Net Present Value ($M)	4	34
Benefit Cost Ratios	1.5	3.0

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
• Bill savings: Reduce customers' electrical operating costs via energy efficient construction and operation of buildings. • Make smart choices with their power: Access to energy information and providing tools and new technologies, allowing customers to optimize energy efficiency and construct buildings that are more desirable for occupants. • Other non-energy benefits depending on the project (e.g., enhanced building value and lease rates etc.) • Remove financial barrier: Incentives to help overcome customers' financial hurdle rates and lower project payback period to an acceptable level.	• Platform to support market transformation through energy efficient design: Identify energy savings by promoting and funding the design of energy efficient buildings that exceeds the minimum building code legislation required, providing industry training and education to help condition the market for the introduction of the next building code. Furthermore, this transformation strategy serves to increase the industries' level of compliance with the current building code. • Support advancement in building design, systems and technology: Increase market demand that supports research, demonstration and development towards more efficient buildings and technologies.	• Demonstrate commitment and support for helping customers to more easily do business with us: Seen as a trusted and credible partner to support customers and industry achieve their goals. • Support customer service: Ability to integrate customer strategy initiatives as necessary to ensure optimized delivery of offers. • Retain flexibility: The program focus can be adjusted as the adoption of the BC Energy Step Code progresses, and new opportunities such as low-carbon electrification arise.

6.3.2 Description

	Detailed Description
Pre-engagement: Design team kick off meeting	Conservation and Energy Management will conduct a Design team kick-off meeting in the early stages of building design. It's essential for the success of the potential Energy Study to have a design team kick-off meeting with the customer, design team, and BC Hydro program representatives to ensure a good understanding of program's requirements and deliverables. This step occurs prior to submitting the Energy Modelling Study Proposal. This initial step helps customers and BC Hydro determine if there is a viable opportunity to explore. The Project Workbook contains preliminary building and/or equipment information and estimates for the project as well as relevant contact and project team information.
Energy Study Proposal	After a design kick off meeting is conducted and the project meets program core eligibility requirements, the applicant must complete and submit a complete Energy Study Proposal Workbook to BC Hydro. The purpose of this submission is to document the project details, including design team to be involved in the study with qualification, building baseline, scope of work, and the study cost breakdown for funding approval consideration.
Energy Study	The Energy Study provides customers with detailed technical information, quantified energy information and expected implementation costs. The study can be used to determine the most effective energy conservation measure for implementation. The study along with BC Hydro support includes among other detailed analysis: • Reviewing modelled baseline and proposed energy consumption; • Electrical and Mechanical Systems requirements; • Building Envelope thermal bridging analysis; • Costing; and • Design options, bundled measures along with interactive effects.
Project Implementation Funding	Project Implementation funding is available to help customers reduce the capital cost of implementing the identified measures. Upon review of the study and subject to adherence to program rules and passing economic cost tests, customers are offered a capital incentive agreement for signature.
BC Hydro Technical Expertise	BC Hydro will provide project specific internal technical assistance and support to the customer throughout a project to allow for an integrated customer experience.

6.4 Commercial Energy Management Activities

6.4.1 Overview

The objective of the Commercial Energy Management Activities is to provide information and tools that assist customers to optimize their energy use. These activities also support BC Hydro's commercial Demand-Side Management programs, rates, and codes and standards efforts in achieving their objectives. By encouraging and assisting customers in integrating energy efficiency into their ongoing business practices and company culture through a Strategic Energy Management approach, BC Hydro can both increase the confidence in, and quantity of demand-side management savings.

The Commercial Energy Management Activities provide Strategic Energy Management training and resources (including Commercial Energy Managers), audits, and support required to enable the customer to implement, operate, and maintain facility changes. As part of these, building energy monitoring and optimization are implemented to better understand and use customer energy data to improve their energy performance and increase building efficiency. The flexible design of the activities and the established relationships with the different customer segments establishes a platform to offer new services such as capacity focused demand-side management.

In addition, customers have access to trained and qualified trade allies/supply-chain partners to help them assess facility opportunities, complete their projects, and access energy information support. Customer interest from utilizing energy information generates market pull, while our partnerships (supply-chain and other) can lead to market push, ultimately resulting in the increased penetration of energy-efficient technologies and energy management solutions. These relationships with industry will also allow for a relatively seamless add new efficiency offers in the future.

Annual Plan	$ million	GWh/yr
F2020	6.2	n/a
F2021	6.1	n/a
F2022	6.1	n/a
Target Market	All Commercial customers who require assistance to make the best decisions around energy management for their business. Can be utilized by public sector, small and medium business, and private sector	
Key Components	• Energy Management Assessment and Plan • Energy Managers • Investigative Energy Study & Building Optimization Study • Energy Wise Network / Campaign in a Box • BC Hydro Alliance of Energy Professionals • External Workforce Capability Building • Customer Information Support	

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
• Energy management information, advice, and program access support • Assistance in accessing qualified energy management products and industry expertise • Increased availability of energy management expertise and quality within industry • Reduce customers' electrical operating costs • Improve corporate culture around strategic energy management • Low-cost/ no-cost support is particularly beneficial for the public sector and small and medium businesses	• Energy Management as a career has grown including all the associated support services • Training and support on BC Hydro programs, various technologies, and changes in codes and standards • Business development – Partners are able to expand their suite of products and services to customer • Support advancement in research and development of energy efficient end uses	• Improved communication channel with industry and customers • The trade ally network effectively sells and promotes BC Hydro programs to customers • Market and technical insights including technology adoption and new customer opportunities are more easily surfaced • Market feedback on Demand-Side Management program effectiveness • Risk mitigation by ensuring engineering consultants and contractors are trained and qualified • Foundational platform for future offers to this customer segment such as demand response, low-carbon electrification, or other technology or service

6.4.2 Description

	Detailed Description
Energy Management Assessment and Plan	Energy Management Assessment: A diagnostic workshop with an organization's senior management to review practices and procedures regarding the organizations energy management practices to move them towards best practices and feed into the Strategic Energy Management Plan. Strategic Energy Management Plan: A one to three-year plan that captures strategic (i.e., corporate policies, metrics, targets), enabling (i.e., recognition, behavioural change, organizational structure) and functional (i.e., operating procedure, procurement, reporting) energy management components. The plan captures energy savings opportunities and aligns with corporate budgets and targets.

	Detailed Description
Energy Managers	The Energy Manager represents the critical first step – secure a dedicated energy champion within an organization that can work with the company's senior management team to help create and implement a corporate level strategic energy management program with targets. The Energy Manager also utilizes various tools and resources (i.e., energy data, capital incentives, energy study funding, and behavioural/operational initiatives) to ensure the company's energy policies and long-term goals are met through energy savings initiatives. Energy Manager Associates are available to key account customers without an Energy Manager and help customers take a strategic approach to energy management and create organizational change to reduce energy waste and improve energy intensity. They provide customers with: access to educational and training events, resources and tools to develop Strategic Energy Management Plans, tracking and reporting templates, diagnostic workshops, and mentoring from BC Hydro funded Energy Managers. The Shared Energy Manager and the Business Energy Advisor is an adaptation of the Energy Manager model that is customized for small and medium business. These individuals will target select commercial customers utilizing various marketing techniques (i.e., propensity modelling) and introducing a strategic energy management concept and approach within their organization. Conservation and Energy Management will support and deliver technical training and education events for Energy Managers to further advance the skills and knowledge of best practices related to building systems, technology, and strategic energy management.
Investigative Energy Study and Building Optimization Study	The Investigative Energy Study is used to determine the most effective energy conservation measures for implementation across an entire building or campus. The study also includes financial analysis that includes payback and ROI, based on the recommended energy conservation measure solutions that best fits the customer's needs. The act of increasing building performance through improved operations (as opposed to equipment retrofits) is referred to as recommissioning. Recommissioning studies review the cost, energy savings, and payback of various operational measures (e.g., reducing equipment run time during unoccupied hours). Industry standards and technology advances, particularly in the area of software (e.g., artificial intelligence), are facilitating the development of new types of software tools to improve and optimize building operations. The Strategic Energy Management Hub is an online tool to support customers in the strategic management of their portfolio of buildings aligned with historical and active energy efficient projects with the ability to run energy analytics. Customers can improve building operations by leveraging new tools that access more granular building energy information such as Anomaly Detection and Diagnostics, Cumulative Sum of Saving Tool (shows the cumulative savings from energy management measures implemented in a building relative to a defined baseline), Consumption trends and Energy Use Intensity.

	Detailed Description
Energy Wise Network / Campaign in a Box	Change management includes social marketing and behavioural economic techniques to target end users to ensure a culture of energy management is embedded within the organization which helps to change the behaviours of employees. The Energy Wise Network provides customers with education, campaign toolkits, diagnostic tools, mentoring support, and funding to implement campaigns to engage employees in their organization to use energy wisely. Campaign in a Box provides a scalable version for small and medium businesses to seamlessly adopt within their organization.
BC Hydro Alliance of Energy Professionals	The BC Hydro Alliance of Energy Professionals is a network of contractors, consulting engineers, distributors and registered experts that will promote the use of energy management and efficiency solutions to our customers. BC Hydro leverages the Alliance members' ability to sell and promote energy efficient products, services and programs to assist our customers within the context of demand-side management programs which is a cost-effective approach to minimize program marketing expenditures. BC Hydro delivers training to Alliance members to ensure they are educated on energy management and trained on the details of the available BC Hydro programs. This goal is achieved in part through partnerships with associations for development and delivery of courses and workshops. BC Hydro has developed an online catalogue of energy efficient products that provides contractors, distributors, and manufacturers with easily accessible specifications of products that are supported within BC Hydro programs. The BC Hydro Alliance of Energy Professionals also enables Conservation and Energy Management to monitor and assess the quality of work that customers receive from Alliance members, and take remedial action if deficiencies are identified.
External Workforce Capability Training	A critical success factor for the Demand-Side Management Plan is that there is an available and accessible "energy efficiency skilled" workforce in place in B.C. BC Hydro plays an important role in identifying and filling skill gaps in the workforce by partnering with post-secondary institutions and industry associations who develop and deliver new training and educational programs. The objective of education and training is to develop and build market capacity of individuals that will be qualified to become energy managers and energy champions within customer and industry organizations as well as to grow the pool of qualified individuals who can join trade ally firms. This will support program participation, increase awareness and action and ultimately integrate efficiency into ongoing business processes. This initiative includes integrating energy management modules within targeted disciplines of academic and training institutions as well as the development of materials to educate customers and trade allies. This provides support for students enrolled in post-secondary institutions, addressing the adequacy requirements of the Demand-Side Measures Regulation.
Customer Energy Information Support	BC Hydro assists our customers to resolve their energy related inquiries and become more educated on how to access our programs and energy saving opportunities. The Customer Support Centre (call centre) provides a first call/email option for our customers to find out more about their specific energy inquiries. Additionally they provide, through the Business Help Desk (a group of specialized agents), a channel of support for specific energy management program inquiries.

7 Industrial Sector Programs

7.1 Industrial Sector Overview

BC Hydro's industrial sector is comprised of over 43,000 customer sites, from family-run farms to large mining operations. Sectors that are the most likely to engage in BC Hydro's industrial demand-side management programs include agriculture, manufacturing, transportation, forest products, pulp and paper, and mining.

7.1.1 Sector Strategic Approach

The Industrial programs are designed to capture demand side management energy savings at industrial facilities by helping customers overcome the financial, technical, and business barriers to energy efficiency. By encouraging and assisting customers in integrating energy efficiency into their ongoing business practices and company culture through a Strategic Energy Management (**SEM**) approach, BC Hydro can increase the quantity of demand-side management savings. For new facilities or system retrofits, BC Hydro also helps customers identify efficiency opportunities with education, resources and funding. Where needed, BC Hydro provides incentives to support the implementation of capital projects that would otherwise not happen.

The Industrial sector program is built on the foundation of SEM. Offers are available to all customer segments, with more focus on sectors that offer the largest and most cost-effective opportunities. The suite of offers includes financial resources as well as tools and education to help customers adopt an SEM model, identify and implement capital projects that will result in energy savings, and affect organizational culture to reduce energy waste and improve energy intensity. This approach will achieve cost savings, keep rates low, and support a trusted relationship with customers.

The design and implementation of BC Hydro's industrial demand-side management programs incorporate the following:

- Programs are designed to encourage the adoption of SEM principles, promoting efficiency and contributing to market transformation;

- Programs will be designed to be as flexible as possible, to allow for timely adjustments to meet BC Hydro's needs;
- Program delivery will be as broad as budgets allow, and enhance customer satisfaction with BC Hydro; and
- Programs will foster economic development in B.C., through the support of the energy efficiency industry, and the benefits to customers of lower energy costs.

As customer needs and expectations change and evolve, so will the Industrial sector programs. Placing more emphasis on SEM by leveraging new information and technology will provide customers with better insights on their electricity consumption. SEM also enables them to develop organizational energy efficiency policies and targets. Building relationships with customers centered on energy will allow BC Hydro to further adapt to changing customer needs, and to make informed decisions on potential future programs such as capacity focused demand-side management.

7.2 Leaders in Energy Management – Industrial (LEM-I)

7.2.1 Overview

The Leaders in Energy Management Industrial (**LEM-I**) program is designed to capture demand-side management energy savings at industrial facilities by helping customers overcome the financial barriers to energy efficiency. Customers have access to Energy Efficiency Feasibility Study funding to build the business case for electrical efficiency projects. Customers then have access to project incentives to reduce the payback required to make these projects financially feasible if needed.

The LEM-I program combines previous programs focused on industrial Transmission (Transmission Service Rate) customers and industrial Distribution (General Service Rate) customers separately. The newly combined LEM-I program will allow BC Hydro to find efficiencies in program delivery, maintain flexibility, and communicate with industrial customers in a way that is independent of rate class. Sectors covered are large customer segments with common interests and energy opportunities, including Pulp and Paper, Wood Products, Mining, Oil and Gas, Chemical, Cement, Manufacturing, Food and Beverage and Transportation.

The LEM-I program provides business case support to enable the customer to implement facility changes, and benefit from the Transmission Service Rate or General Service Rates. Customers can also access capital incentives for upgrades to existing plants or to support efficient plant expansions. When combined with the Industrial Energy Management Activities, a company can develop a comprehensive plan to continue saving energy at their facility.

Annual Plan	**$M**	**GWh/yr**
F2020	18.3	132
F2021	18.5	136
F2022	17.9	92
Target Market	Large Industrial (Transmission Service Rate) Customers. Approximately 170 sites. Largest 2,000 Industrial Distribution (General Service Rate) Customers. Approximately 43,000 small industrial customers also have access.	
Key Components	Energy Studies	
	Project Incentives	
	New Plant Design	
Cost Effectiveness	**Utility Cost (Market Price at $30 per MWh)**	**Modified Total Resource Cost (LRMC at $105 per MWh)**
Net Levelized Cost ($/MWh)	12	(22)
Net Present Value ($M)	37	267
Benefit Cost Ratios	1.8	4.4

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
• Bill savings: Reduce customers' electrical operating costs. • Remove financial barriers: Incentives to help overcome customers' financial hurdle rates and lower project payback period to an acceptable level. • Other non-energy benefits depending on the end-use/project (e.g., maintenance savings, enhanced output/product quality etc.)	• Competiveness: Builds more efficient and competitive industrial facilities in B.C. • Support advancement in technology: Increase market demand that supports research and development towards more efficient end uses. • Economic: Creates a need for services to support efficiency studies and equipment installations.	• Demonstrate commitment and support for helping customers to more easily do business with us: Seen as a trusted and credible partner to support customers and industry to achieve their goals. • Retain flexibility: The offer can be adjusted quickly to changing internal and external demands by scaling up or down, adding funding partners or new program measures. .

7.2.2 Description

	Detailed Description
Energy Studies	Conservation and Energy Management has assembled an external team of North America's top energy efficiency engineers/technologists to investigate and quantify energy efficiency opportunities within our customers' facilities. The LEM-I program offers Energy Efficiency Feasibility Studies to quantify opportunities and build the business case for project implementation.
Project Incentives	Incentives provide additional financial assistance to overcome the affordability barriers that have been impeding projects with longer payback periods.
New Plant Design	The New Plant Design initiative offers industry expertise to provide energy base lining and energy-efficiency design support for new or expanding facilities. These findings are combined with project incentives to encourage efficient designs that surpass industry standards.

7.3 Thermo-Mechanical Pulp Program

7.3.1 Overview

The Thermo-Mechanical Pulp Program provides assistance to BC Hydro's thermo-mechanical pulp customers to manage their electricity consumption and complete projects at their facilities. The program targets the six thermo-mechanical pulp sites and provides incentives for projects that help modernize their processes. Order in Council 404, dated July 14, 2015, directs the BCUC to allow BC Hydro to recover expenditures related to the TMP Program through rates to a maximum expenditure of $100 million.

Annual Plan	$ million	GWh/yr
F2020	0	0
F2021	27.2	100
F2022	0	0
Target Market	Thermo-Mechanical Pulp sites: Catalyst Paper, Powell River, Catalyst Paper, Crofton, Catalyst Paper, Port Alberni, West Fraser, Quesnel River Pulp, Canfor Pulp, Taylor	
Key Components	Energy Studies	
	Project Incentives	
Cost Effectiveness	**Utility Cost (Market Price at $30 per MWh)**	**Modified Total Resource Cost (LRMC at $105 per MWh)**
Net Levelized Cost ($/MWh)	23	34
Net Present Value ($M)	5	53
Benefit Cost Ratios	1.2	2.7

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
• Financial incentives for facility improvements. • Access to energy industry professionals. • Improved site viability	• Builds more efficient and competitive thermo-mechanical pulp facilities in B.C. • Creates a need for services to support efficiency studies and equipment installations	• Contributes to the demand-side management plan and reduces future generation costs. • Helps keep mills viable to retain revenue.

7.3.2 Description

	Detailed Description
Energy Studies	The Thermo-Mechanical Pulp program offers Energy Efficiency Feasibility Studies to quantify opportunities and build the business case for project implementation. Goal: Provide access to industry experts who can help industrial customers study facilities and build business cases for energy improvement projects.
Project Incentives	The incentive provides additional financial assistance to overcome the affordability barriers that have been impeding these large projects. Goal: Reduce payback periods and provide access to capital for hard-wired energy improvement projects that would otherwise not be implemented at thermo-mechanical facilities.

7.4 Industrial Energy Management Activities

7.4.1 Overview

The Industrial Energy Management Activities are designed to support industrial facilities by assisting customers overcome the management and business barriers to energy efficiency. By encouraging and assisting customers in integrating energy efficiency into their ongoing business practices and company culture through a Strategic Energy Management (**SEM**) approach, BC Hydro can increase the quantity of demand-side management savings.

Sectors are large customer segments with common interests and energy opportunities, including Pulp and Paper, Wood Products, Mining, Oil and Gas, Chemical, Cement, Manufacturing, Food and Beverage and Transportation.

The Industrial Energy Management Activities provide SEM training and resources including Industrial Energy Managers. Audits and support are provided to enable the customer to implement and maintain facility changes. Through SEM, customers will also benefit from the Transmission Service Rate or General Service Rates. As part of the program, Energy Monitoring and Targeting systems are implemented at customer sites to understand and use customer energy data to improve energy performance and increase operational efficiency. The flexible design and the relationships with the customers create a platform to offer new services such as capacity focused demand-side management.

Annual Plan	$M	GWh/yr
F2020	8.2	n/a
F2021	8.4	n/a
F2022	8.5	n/a
Target Market	Active partnerships with 83 Industrial sites. (Transmission Service Rate) Customers. Approximately 170 sites. Largest 2,000 Industrial Distribution (General Service Rate) Customers.	
Key Components	Strategic Energy Management – Industrial Energy Manager	
	Strategic Energy Management – Cohort Energy Manager	
	Strategic Energy Management – Regional Energy Manager	
	Energy Monitoring and Targeting	
	Energy Audits	
	BC Hydro Alliance of Energy Professionals (across all sectors)	
	External Workforce Capability Building (across all sectors)	

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
• Energy management information, advice, and program access support • Improve corporate culture around SEM: A strategic approach by supporting organizations to develop a sustained corporate level strategic energy management program. • Assistance in accessing qualified energy management products and industry expertise • Energy Monitoring and Targeting: Access to energy data to improve operational efficiency.	• Competiveness: Builds more efficient and competitive industrial facilities in BC. • Industry capacity: Support and grow the energy management industry through the BC Hydro Alliance of Energy Professionals. • Support advancement in technology: Increase market demand that supports research and development towards more efficient end uses. • Economic: Creates a need for services to support efficiency studies and equipment installations.	• Demonstrate commitment and support for helping customers to more easily do business with us: Seen as a trusted and credible partner to support customers and industry achieve their energy management goals. • Foundational platform for future offers to this customer segment: Demand response, low-carbon electrification, or any other technology or service. • Support Customer Service: Ability to integrate customer strategy initiatives as necessary to ensure optimized delivery of offers. • Retain flexibility: The offer can be adjusted quickly to changing internal and external demands by scaling up or down, adding funding partners or new program measures. • Support towards market transformation: Emphasis on market transformation and education of key stakeholders by providing the right tools and resources.

7.4.2 Description

	Detailed Description
Strategic Energy Management: Industrial Energy Manager	The SEM Industrial Energy Manager offer provides funding to industrial customers to embed strategic energy management practices into their organizations. BC Hydro will provide funding for an Industrial Energy Manager who will receive specialized training and knowledge on developing and implementing an SEM plan. The initiative includes energy assessments to assist customers to gain energy insights, build executive support for energy efficiency and define the energy opportunity and value proposition for their company. Industrial Energy Managers have access to additional funding and resources for Employee Awareness initiatives and enhanced Energy Monitoring and Targeting at their organization. The objective is to drive energy improvements through increased SEM practices at large industrial facilities with increased use of energy intelligence, monitoring and reporting, business processes, and awareness.

	Detailed Description
Strategic Energy Management: Cohort	The SEM Cohort Energy Manager offer is intended to build SEM at customer sites that are not large enough to support a dedicated Industrial Energy Manager. We bring together a group of industrial customers to work together and share knowledge related to building energy management in their business. The goal is to translate these insights into changes in daily business operations by using a customer's own energy data to build a facility-wide energy model that will help them to continuously improve their energy performance. Through the systematic use of energy data, operational models are created for small and medium industrial facilities that enable the identification and monitoring of energy improvements.
Strategic Energy Management: Regional Energy Manager	The SEM Regional Energy Manager offer is intended to build SEM at small to medium sized industrial customer sites. Two Regional Energy Managers will help small to medium sized industrial customers to understand SEM and enroll in the Operational Energy Analytics offer. Through Operational Energy Analytics leveraging SMI and MyHydro, the customers will go through an onsite audit and several months of data monitoring to enable operational savings at their facilities.
Energy Monitoring and Targeting	Energy Monitoring and Targeting is designed for SEM participants to identify process anomalies or new projects (operational or capital) that result in operational or hard-wired savings. Customers will also be able to quantify/validate savings through the development of an accurate energy monitoring and targeting model and deployment of reporting capability at the facility or subsystem level
Energy Audits	Conservation and Energy Management has assembled an external team of North America's top energy efficiency engineers/technologists to investigate and quantify energy efficiency opportunities within our customers' facilities. The Industrial Energy Management activities offer Plant-Wide Audits and End Use Assessments to identify energy-saving opportunities at industrial facilities. The objective is to provide access to industry experts who can help industrial customers audit facilities and identify energy improvement projects as part of a corporate strategic energy management plan.
BC Hydro Alliance of Energy Professionals	The BC Hydro Alliance of Energy Professionals is a network of contractors, consulting engineers, distributors and registered experts that will promote the use of energy management and efficiency solutions to our customers. BC Hydro leverages the Alliance members' ability to sell and promote energy efficient products, services and programs to assist our customers within the context of demand-side management programs which is a cost-effective approach to minimize program marketing expenditures. BC Hydro delivers training to Alliance members to ensure they are educated on energy management and trained on the details of the available BC Hydro programs. This goal is achieved in part through partnerships with associations for development and delivery of courses and workshops. The BC Hydro Alliance of Energy Professionals also enables Conservation and Energy Management to monitor and assess the quality of work that customers receive from Alliance members, and take remedial action if deficiencies are identified.

	Detailed Description
External Workforce Capability Training	A critical success factor for the Demand-Side Management Plan is that there is an available and accessible "energy efficiency skilled" workforce in place in B.C. BC Hydro plays an important role in identifying and filling skill gaps in the workforce by partnering with post-secondary institutions and industry associations who develop and deliver new training and educational programs. The objective of education and training is to develop and build market capacity of individuals that will be qualified to become energy managers and energy champions within customer and industry organizations as well as to grow the pool of qualified individuals who can join trade ally firms. This will support program participation, increase awareness and action and ultimately integrate efficiency into ongoing business processes. This initiative includes integrating energy management modules within targeted disciplines of academic and training institutions as well as the development of materials to educate customers and trade allies. This provides support for students enrolled in post-secondary institutions, addressing the adequacy requirements of the Demand-Side Measures Regulation.

8 Capacity Focused Demand-Side Management

8.1 Overview

Capacity-focused demand-side management initiatives were identified as a new area of potential in the 2013 Integrated Resource Plan and are currently being tested in the market to understand the magnitude and dependability of the capacity savings for inclusion in BC Hydro’s planning as potential alternatives to new generation capacity or grid (transmission or distribution) infrastructure. System capacity needs are during the high-demand winter season as well as shoulder months when the load resource balance is tight due to maintenance outages, whereas grid capacity needs depend more on the particular location.

Over the fiscal 2020 to fiscal 2022 period, this initiative will build on the work to date to further explore and identify the opportunity to use customer-based, demand-side measures as a resource to manage capacity constraints on the grid. These trials and pilots include:

- **Residential demand response trials** include the testing for customer acceptance and performance, including smart charging of electric vehicles, specialized charging stations for multi-unit residential buildings, behavioural demand response (Peak Saver), smart water heater controls, home-based storage (batteries), electric thermal storage and other emerging technologies;
- **Commercial and industrial demand response trials** include the use of customer-sited batteries, connected building technologies, building management system integration for demand management purposes, smart charging of electric vehicles (including fleets and employees) and vehicle to grid;
- **Localized demand-side management pilots** will leverage the combination of various demand response technologies tested in demand response trials in conjunction with targeted energy efficiency offers to meet the unique needs of a constrained distribution asset (such as a substation or feeder.) BC Hydro will pursue opportunities in constrained substations utilizing solutions tested in the residential, commercial and industrial demand response trials. BC Hydro plans to test out different solutions in a

number of constrained areas. This will allow BC Hydro to determine whether demand response activities can shift the timing of the peak demand of a local area;

- **Connected Home product trials** are designed to address this emerging market space that could have impacts on the utility in the context of both load management and energy efficiency. This area of investigation includes customer's acceptance and adoption of centralized home hubs and supporting equipment that facilitates new ways for customers to utilize energy in their home. This can include control equipment and portals that can provide more detailed and timely energy intelligence to occupants / homeowners. The goal is to understand how these new technologies could be used to help manage energy use and contribute to reducing the impact on local and system-wide capacity; and
- **Infrastructure Development** – research, analysis and development of core policies, procedures, support infrastructure, benefits and valuation of capacity initiatives, planner needs, and business models for various capacity-focused demand-side management programs including items such as settlement procedures and localized load forecast tool development. A key infrastructure component will be a Distributed Energy Resource Management system to address one of the important lessons learned to date from the various capacity-focused demand-side management activities: the need to have a system in place that can manage the devices, programs, customers and program operation, including direct communication to the end-use. To meet this need, BC Hydro has identified implementing a demand response management/distributed energy resource management system over fiscal 2019 to fiscal 2021.

This portfolio budget has been extended over a longer period of time than originally planned due to the complex nature of the impacts to BC Hydro's system and value streams, the desire to incorporate past learnings into the new activities, the rapidly changing technology landscape, and the long lead times required for some customer projects. The total amount of the required budget over fiscal 2017 to fiscal 2021 has also been reduced by 12 per cent.

Annual Plan	$ million	
F2020	6.9	
F2021	4.3	
F2022	0	
Target Market	All sectors	
Key Components	Residential Demand Response - appliances, electric vehicle chargers, storage, behavioural	
	C&I Demand Response – storage, EV charging, connected building, behavioural and operational	
	Localized demand-side management	
	Connected Buildings	
	Infrastructure Development	
Cost Effectiveness	**Utility Cost (Market Price at $30 per MWh)**	**Modified Total Resource Cost (LRMC at $105 per MWh)**
Net Levelized Cost ($/MWh)	n/a	n/a
Net Present Value ($M)	n/a	n/a
Benefit Cost Ratios	n/a	n/a

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
• Financial incentives for shifting/curtailing load • Access to new controls or information to better manage energy and demand • Defers or eliminates construction in local communities • Improves local reliability • Supports electrification by helping to mitigate costs (e.g., panel management) • Better understanding of capacity opportunities (which is an area of investigation that customers have desired)	• Allows industry players to have more comprehensive solutions to provide customers (energy efficiency plus capacity initiatives) • Creates demand for products and services to support project implementation, such as equipment installations	• Defers generation capacity costs • Defers distribution capacity infrastructure costs • Integrates approach to jointly manage all aspects of electricity usage • Improves system reliability • Creates demand side flexibility • May facilitate electrification and customer connections to the system by addressing capacity constraints

8.2 Description

	Detailed Description
Demand Response	Demand response solutions for residential, commercial and industrial customers can help facilitate a more flexible load on the demand side, potentially creating efficiencies and cost savings for BC Hydro and the customer. This area continues to focus on exploring and developing experience with loads that can respond to conditions on the grid. These areas include: • Managed charging for residential and commercial passenger fleets, forklifts and other vehicles; • Energy storage (batteries, thermal storage); • Interactions and opportunities between energy storage, charging, and the grid; and • Other emerging opportunities for flexible load.
Localized Demand-Side Management	Localized Demand-Side Management projects target capacity constrained substations and distribution assets, through a combination of demand-side measures can be offered to reduce overall peak load and reduce the need for capital investment due to load growth. • Each geographically targeted area would receive a package of energy efficiency and demand response programs targeted towards the specific loads in the area. In the future, this package could also include distributed energy resources and storage. • Includes solutions for all sectors, based on opportunities in the targeted areas. For example, for a substation with a large residential load, water saving devices may help not only reduce overall energy use (energy efficiency through reducing the amount of hot water used) but can also help reshape load because most hot water usage is concurrent with system peaks.
Connected Buildings/ Facilities	For BC Hydro, the goal is to increase load flexibility by increasing the ability of buildings to interact with the grid and adjust loads to balance supply and demand. Connected buildings are emerging, as the internet of things allows for more granular control and monitoring. • For residential customers, there will be a variety of initial offers involving central hubs and connected devices such as thermostats. Participants receive equipment, are provided with energy conservation and connected technology use tips and are monitored to understand how they interact with this new information and control capabilities as well as the impact on their energy usage. • For a small number of customers, opportunities for connected, intelligent buildings will be examined through a series of trials. Participants will receive incentive funding towards the implementation and study of connected building technologies and their impacts. Industrial facilities will be able to integrate energy use dashboards and displays into their processes to manage real-time events on the system.

<table>
<tr><th></th><th>Detailed Description</th></tr>
<tr><td>Infrastructure Development</td><td>All program delivery requires infrastructure to support it, including core policies, procedures, skills and technology. This area focuses on understanding the different requirements of capacity-focused demand-side management vs existing conservation and energy efficiency offers and what gaps may need filling to roll out at scale.
Understand best practices for capacity-focused demand-side management program delivery
Test any IT or supporting systems (such as a Distributed Energy Resource Management system) to facilitate the efficient and effective operation of various programs.
Continue to work with internal stakeholders to understand benefit streams, valuation, operational requirements, and other stakeholder needs.</td></tr>
</table>

9 Codes and Standards

9.1 Overview

To achieve its energy conservation targets and as required by the Demand-Side Measures Regulation, BC Hydro supports government implementation of new and updated codes and standards, which set efficiency requirements in building codes, product and equipment standards, bylaws and community energy plans. BC Hydro drives and supports energy efficiency code and standard development by working with the Federal government, Government of B.C., key municipal governments and indigenous communities in B.C. through committees, programs and peer networks. In addition, the Codes and Standards initiative enables and facilitates implementation of new code requirements by driving and supporting capacity building initiatives in partnership with government, industry and educational facilities to transform the marketplace to energy efficient practices and products. These initiatives include project implementation funding offers, pilot projects, research, industry training and education programs, community planning support, and partial funding of positions within key organizations that support codes and standards development and implementation.

Codes and Standards activities target local governments, indigenous communities, the residential and commercial building sectors, as well as industry, supplier and manufacturing sector to achieve its market transformation objective. The positive, long-lasting relationships with stakeholders and successful deployment of initiatives can be utilized in the future to advance new offers.

Annual Plan	$ million	GWh/yr
Fiscal 2020	5.2	356
Fiscal 2021	5.3	411
Fiscal 2022	5.4	282
	Codes and Standards Investigation, Development & Implementation	
	Peer Networks	
Key Components	Community Planning	
	Community Energy Manager, Building Department & Intern Offers	
	Project Implementation Offer	
	Indigenous Communities Policy Support	
	New Construction Capacity Building and Industry Support	

Annual Plan (GWh/yr)	Residential	Commercial	Industrial	Total
Fiscal 2020	238	107	12	356
Fiscal 2021	246	153	12	411
Fiscal 2022	150	125	7	282

Refer to Appendix C for detailed breakdown of energy savings by technologies.

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
• Energy conservation • Market transformation measures strongly integrate affordability factors • Tools, financial and technical support for communities (local governments and Indigenous Communities), as well as commercial Energy Management Activities • More high performance homes and commercial buildings in B.C. market	• Policy and Codes roadmaps provide market certainty • Local government support and implementation projects channeled to support market transformation • Collective forum for informing and advising on smooth market transformation • Partnerships, training and support for the building industry to move to more energy efficient building practices	• Driving market transformation through convening partnership efforts rather than program based approaches • Cost-effective demand-side management • Strengthens relationships with local governments and Indigenous Communities. • Relationships with Federal and Provincial governments to advance energy efficiency Codes and Standards

9.2 Description

	Detailed Description
Codes and Standards Investigation, Development & Implementation	The initiative seeks to address the availability, awareness, acceptance barriers that are holding back the development of new energy efficiency codes and standards, and the adoption of more energy efficient building practices and products. Those barriers are reduced by: • Providing technical and financial support to governments and standard developing organizations for the development and identification of comprehensive and effective energy efficiency standards, regulations, codes and other government policy instruments. • Building stakeholder support with other Canadian and U.S. utilities (e.g., in the Pacific Northwest) for changes to codes and standards. • Supporting trade allies and building officials in their compliance with codes and standards via training and education for industry. • Supporting governments in their compliance checking / enforcement of codes and regulations by providing market intelligence on energy-efficient equipment stocking and building construction practices as well as co-funding support for code compliance enhancement efforts with all three levels of government. This initiative is a specified demand-side measure per the Demand-Side Measures Regulation, and per section 3(1)(e), expenditures of 1 per cent of the Plan or $2 million are required to meet the adequacy requirements of the Demand-Side Measures Regulation. In this Plan, we expect to spend approximately $5.2 million annually on codes and standards support, and therefore meet the adequacy requirement.
Peer Networks	A critical element of market transformation is creating networks, maintaining partnerships and driving collective work plans so that partners coordinate the use of their different levers towards the common objectives. • Energy Step Code Council (21 government, utility and industry organizations): – Training and Communications Subcommittee; – Technical Subcommittee; – Compliance and Energy Advisor Subcommittee; – Local Governments Peer Network (large communities); and – Local Government Peer Network (small communities); • Building Officials' Association of BC (**BOABC**) Energy Foundations Program Peer Network; • Anticipated in the future: – Builder Peer Network through Local Energy Efficiency Partnerships (**LEEP**) and Canadian Home Builders Association (**CHBA**) National; – Realtor, Labeling and Consumer Awareness; and – Retrofit Network.
Community Planning	Funding for target market local governments (population over 75,000) to embed energy considerations in community planning processes. This offer supports community energy and emissions plans, local area plans (neighborhood plans), green building strategies and electric vehicle strategies.

	Detailed Description
Community Energy Manager, Building Department & Intern Offers	These offers support the addition of resources within target market local governments in order to implement work plans that make use of local governments levers to drive energy efficiency and broader offers at the community scale Work plan development includes strategic planning assessments and benchmarking with senior management from local governments.
Project Implementation Offer	Funding for target market local governments to support implementation of efficiency policies and actions at the community scale.
Indigenous Communities Policy Support	There are unique geographic and market barriers facing Indigenous and remote communities. In an effort to better understand and address these unique barriers, pilot activities were undertaken between fiscal 2017-fiscal 2019. New offers will be launched to provide capacity building support to Indigenous and remote communities as follows: • Funding for the development and implementation of community energy plans that articulate both short and long-term opportunities and actions for community energy management; • Funding for staff positions at the Band or Tribal Council level to embed knowledge and capacity in the community to support the advancement of programs and projects; • Delivery of education and skills training initiatives to build energy literacy in the community, empower community members to manage energy use and reduce energy costs, and foster local economic development opportunities related to energy (e.g., new high performance housing, energy efficient building upgrades, etc.); and • Funding and technical resources to support the development and implementation of energy efficient building policy to ensure that new buildings on reserve are built to higher energy performance standards (Energy Step Code) and that existing buildings are upgraded to improve energy performance over time. This policy and planning support will work in conjunction with the customer focused Indigenous offers within the Low Income Program (for BC Hydro grid connected customers) and the new Non-Integrated Areas program (for customers in communities that are not connected to the BC Hydro integrated electric system).

	Detailed Description
New Construction Capacity Building and Industry Support	BC Hydro works with residential builders, developers, energy advisors, realtors, other industry partners and government to create demand for and construct homes that are more energy-efficient than the B.C. Building Code minimum requirements. This helps to build awareness and acceptance of the role that step codes can play in transforming the market. Recognizing the need to move beyond influencing individual projects through an incentive strategy, this initiative focuses on activities that leverage deep market changes to transform the construction industry in four key ways: • Create opportunities for diverse access to builder and industry training and education on energy efficiency standards; • Build consumer awareness on the value of higher performance housing for their family and empower them to prioritize these features when buying or building a new home; • Collaborate with industry professional associations and market players to research and identify suitable high performance solutions for the B.C. residential construction market, support market accessibility and mass market adoption of these solutions; and • Work with local governments to streamline approaches to increase code compliance, policy development, and adoption of the BC Energy Step Code. Funding support is provided to local governments for step code implementation initiatives.

10 Rates

10.1 Residential Inclining Block Rate

BC Hydro introduced its Residential Inclining Block rate structure in October 2008. Customers are charged for electricity consumption at two rates, an initial Step 1 threshold of 1350 kWh per two-month billing period charges at a lower rate (as of April 1, 2018, 8.84 cents per kWh); and a higher rate for Step 2 consumption above that threshold (as of April 1, 2018, 13.26 cents per kWh). This provides customers with a price signal that encourages conservation.

The most recent Residential Inclining Block Evaluation Report[18] finds that no new incremental savings are anticipated in future years. However, the current pricing signal continues to encourage customers to maintain previous savings. As shown, no new incremental costs are planned.

Annual Plan	$ million	GWh/yr
F2020	0	0
F2021	0	0
F2022	0	0
Target Market	Residential Sector	
Cost Effectiveness	**Utility Cost (Market Price at $30 per MWh)**	**Modified Total Resource Cost (LRMC at $105 per MWh)**
Net Levelized Cost ($/MWh)	n/a	n/a
Net Present Value ($M)	n/a	n/a
Benefit Cost Ratios	n/a	n/a

10.2 Rate Schedule (RS) 1823, Stepped Rate

The Stepped Rate, also referred to as the Transmission Service Rate, applies to most large customers that are supplied with electricity at transmission voltages (60,000 volts or more). The rate has been in place since April 2006. There are approximately 145 transmission customer sites taking electricity service under the Transmission Service Rate.

[18] Evaluation of the Residential Inclining Block Rate F2013-F2017, April 2018.

The Transmission Service Rate is a two-tier (Tier 1 and Tier 2) inclining block conservation rate where annual energy consumption above a threshold is charged at a higher Tier 2 rate and annual energy consumption up to the threshold is charged at a lower Tier 1 rate. The energy consumption threshold is set at 90 per cent of the plant's historical annual energy consumption (called the Customer Baseline). The result is a 90:10 split in energy pricing. The Tier 2 price was established to provide a conservation price signal and is set based to reflect BC Hydro's Long Run Marginal Cost (**LRMC**). The Tier 1 price is derived from the Tier 2 price and the 90:10 Tier 1/Tier 2 pricing split to achieve revenue neutrality with the former flat rate structure, at 100 per cent of the plant's historical Customer Baseline consumption.

As of April 1, 2018, the Tier 1 price was 4.244 cents per kWh, and Tier 2 was priced at 9.509 cents per kWh. Customers are also charged for electricity demand at a flat rate $8.139 per kVA based on 30min peak kVA demand during High Load Hours (**HLH**).

Annual Plan	**$ million**	**GWh/yr**
F2020	0.5	117
F2021	0.5	118
F2022	0.5	114
Target Market	Industrial transmission customers	
Cost Effectiveness	**Utility Cost (Market Price at $30 per MWh)**	**Modified Total Resource Cost (LRMC at $105 per MWh)**
Net Levelized Cost ($/MWh)	(4)	73
Net Present Value ($M)	12	13
Benefit Cost Ratios	11.1	1.4

11 Supporting Initiatives

11.1 Public Awareness

11.1.1 Overview

The Public Awareness Supporting Initiative is a set of foundational activities that increase the awareness of the general public and K-12 students/teachers about ways to increase energy conservation and energy efficiency, as well as help increase participation in various energy efficiency measures / programs as laid out in the Demand-Side Measures Regulation. Customers' energy literacy and receptiveness to the concept of energy efficiency is elevated as a result of these supporting activities that are designed to address two specific barriers to participation: awareness of activities and programs, and the acceptance of those programs.

This increased awareness and acceptance ultimately sets the stage for improved participation in a variety of behaviours and programs and the support of codes and standards. These activities cover a variety of channels designed to effectively reach a wide cross-section of customers and also includes a schools program.

11.1.2 Area of Focus

Annual Plan	$ million	GWh/yr
F2020	7.4	n/a
F2021	7.5	n/a
F2022	7.6	n/a
	Public Education and Awareness: communications strategies and campaigns delivered via all channels	
	Public Engagement: face-to-face coaching with customers in communities and at sponsorship events	
	Schools Program	

Customer Benefits	Industry Benefits	BC Hydro & Shareholder Benefits
• Builds awareness and understanding of Demand-Side Management programs • Provides customers one source of information and the knowledge to participate in programs	• Supports retailer and manufacturing partners through promotion of products and programs • Support teachers and the Ministry of Education to reach their goals	• Builds one cohesive story in the marketplace across residential, commercial and industrial programs. • Foundational supports for Demand-Side Management program targets • Program can expand to include new concepts around energy analytics and capacity focused offers. • Builds BC Hydro’s reputation and brand of being innovative and supporting a conservation culture.

11.1.3 Description

	Detailed Description
Public Education and Awareness	Continue with core focus on Fall and Spring conservation campaigns and build out more year round content through owned/digital channels. By using a combination of paid, owned and earned communications strategies, BC Hydro is able to reach customers with messages intended to elevate awareness of energy efficiency and encourage residential and business customers to undertake actions. Strategies and messages target a range of demographics including multilingual communications. Efforts place emphasis on digital channels, the development of rich content (video, animation etc.) and the role of social media in elevating awareness and engagement while maintaining a foothold in traditional channels where media consumption habits are still high (TV, radio). Driving customers to bchydro.com and powersmart.ca for in-depth information about tips and programs is a central part of the strategy, with a growing focus on mobile viewing habits. BC Hydro continues to cultivate a rich network of social media and eNewsletter subscribers who receive content daily and monthly outside of campaign windows. In addition, BC Hydro’s media strategy supports conservation year round through storytelling and sharing data and reports that are newsworthy and create buzz in traditional media channels and beyond to online channels.
Public Engagement	Engaging with customers face-to-face helps build awareness and gain support for energy efficiency activities. A focus on engagement allows for rich conversations and dialogue that spark an interest in conservation leading to action at home and in businesses. This initiative includes business and community outreach targeted primarily at home shows, retail stores, community events and business locations, providing information on energy tips, products, and programs. The team acts as personal energy coaches, delivering custom ideas and support to encourage the adoption of energy efficient products, services and behaviours. Focus will be on supporting high need/high opportunity communities such as indigenous communities, low income, and communities with capacity constrained electrical infrastructure.

	Detailed Description
Schools Program	The schools program targets K-12 teachers, students and administrators in an effort to foster awareness and build energy literacy in our next generation of customers through comprehensive, curriculum-based teaching materials, initiatives and face-to-face interactions. The program is primarily delivered through an online platform. The program also includes a strategy to capitalize on nation-wide events such as Environmental Week, Earth Day, and Water Week by creating premium materials and resources for teachers at key points throughout the school year. This support for students addresses the adequacy requirements of the Demand-Side Measures Regulation. The support for the post-secondary education component of the Demand-Side Measures Regulation is described within Commercial and Industrial Energy Management Activities.

11.2 Indirect and Portfolio Enabling

11.2.1 Overview

Running a broad portfolio of programs and initiatives requires additional support activities that are necessary to successfully design, develop, and implement a successful portfolio. These are referred to as Deferred Indirect and Portfolio Enabling activities.

These activities support BC Hydro's Demand-Side Management initiatives with general management and infrastructure, including Demand-Side Management planning and regulatory activities and the development and administration of policy and processes related to the effectiveness and integrity of Demand-Side Management initiatives.

Annual Plan	$ million	GWh/yr
F2020	7.1	n/a
F2021	7.4	n/a
F2022	7.5	n/a
Key Components	• General management • Information Systems • Support and Administration • Training and Education • Support Services	

11.2.2 Description

	Detailed Description
General Management	A portion of the Conservation and Energy Management's business unit's general management of people and resources.
Information Systems	Support, operation and management of Demand-Side Management information systems as well as the planning and management of system enhancements and improved functionality. Demand-Side Management information systems include: • A system to support business customer contact management, account views, project tracking, opportunity and sales management, and energy savings reporting; and • Energy Reporting: systems that support the ability to report on energy savings and program participation
Support and Administration	A portion of the Conservation and Energy Management business unit's general administrative functions including costs associated with administrative activities, photocopy and fax equipment, office supplies, as well as a portion of labour for individual timesheets, expense reporting and benefits administration.
Training and Education	Individual employee training related to demand-side management, including technical seminars and attendance at conferences.
Support Services	Regulatory activities that support regulatory filings and reporting. The development and updating of demand-side management strategy and policies, as well as modelling and cost-effectiveness analysis. Support activities related to the development, administration, and review of general processes, policies, and procedures related to the effectiveness and continuous improvement. Examples include measurement and verification protocols, business or financial audits, and quality assurance.

12 Key Program Assumptions

The following table provides the Key Program Assumptions of the adjustments that apply to the energy savings based on the activities from fiscal 2020 to fiscal 2022. Ranges indicate that there are sub-components within the initiative that have different adjustment factors. Further details can be found in Appendix B Portfolio-Wide Assumptions document.

Sector	Program	Compliance Rate (%)	Cross Effects (%)	Direct Rebound Effect (%)	Free Riders (%)	Market Effects (%)	Persistence (years)	Spill-over (%)
Cross Sector	Building Codes	63-100	0	0	n/a	n/a	30	n/a
	Product and Equipment Standards	70-100	0-6	0	n/a	n/a	30	n/a
	Capacity Focused		n/a	n/a	n/a	n/a	n/a	n/a
Residential	Behaviour Program		0	0	0	0	1, 6, 24	0
	Home Renovation Rebate		0	0-6	0-45	0	9-30	0-44
	Low Income Program		0-5.7	0-6	0-69	0	1-30	0-17
	Non-Integrated Areas	Non-Install (%) 0-80	0-5.7	0-6	5-69	0	1-30	0-17
	Retail Program	Non-Install (%) 0-20	0-5.7	0	10-40	0	6-20	0-10
Commercial	Leaders in Energy Management – Commercial		0-4	0	0-25	0	2-30	0-22
	New Construction Program		1	0	22	0	18	7.6
Industrial	Leaders in Energy Management – Industrial		0	0	14-31.7	0	1-16	11-23
	Thermo-Mechanical Pulp		0	0	0	0	10	0

Definitions	
Compliance Rate	The rate at which customers, retail channels, or builder/develops actually meet the established code or standard (knowingly or unknowingly)
Cross Effects	The effect of an energy efficient action on one energy use causing a change in another energy use. For example, more efficient lighting products typically release less waste heat and thereby reduce air-conditioning load
Direct Rebound	The increased usage of a device or system because it is more energy efficient
Free-riders	Customers who participate in a demand-side management program but who would have undertaken the same change at the same time in the absence of the program
Market Effects	Refers to a change in the structure or functioning of a market or the behaviour of participants in a market that result from one or more program efforts. Typically these efforts are designed to increase the adoption of energy efficient products, services, or practices and are causally related to market interventions. Market effects may include participant and non-participant spillover and market transformation
Persistence	The timeframe during which demand-side management measures produce electricity savings that are attributable to the utility's actions
Spillover	Refers to program participants and non-participants whose energy savings measures occur through actions that are not part of a program, but which were influenced by the program (also called free drivers or tag-ons). Participant spillover is the additional energy savings that occur when a program participant independently installs additional energy efficiency measures or applies additional energy savings practices after having participated in the efficiency program, as a result of the program's influence. Non-participant spillover refers to energy savings that occur when a program non-participant installs energy efficiency measures or applies energy savings practices as a result of a program's influence

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix X

Appendix A

Detailed Financial Tables

1 **Table A-1 Total BC Hydro Costs ($ million)**

	Forecast F2020	Forecast F2021	Forecast F2022	Total: F2020-F2022
Rate Structures				
Residential Inclining Block Rate	0.0	0.0	0.0	0.0
General Service Rate	0.0	0.0	0.0	0.0
Transmission Service Rate	0.5	0.5	0.5	1.4
Total Rate Structures	**0.5**	**0.5**	**0.5**	**1.4**
DSM Programs				
Residential Sector				
Low Income	5.8	6.9	7.8	20.6
Non Integrated Areas	1.2	1.4	1.5	4.1
Retail	2.1	2.1	2.2	6.4
Home Renovation Rebate	4.2	4.4	4.6	13.2
Residential Energy Management Activities	5.0	4.9	5.0	14.8
Residential Sector Total	*18.4*	*19.7*	*21.0*	*59.1*
Commercial Sector				
LEM-C	9.0	9.1	9.2	27.3
New Construction	3.7	2.4	2.0	8.0
Commercial Energy Management Activities	6.2	6.1	6.1	18.4
Commercial Sector Total	*18.9*	*17.5*	*17.2*	*53.7*
Industrial Sector				
LEM-I	18.3	18.5	17.9	54.7
Thermo-Mechanical Pulp	0.0	27.2	0.0	27.2
Industrial Energy Management Activities	8.2	8.4	8.5	25.0
Industrial Sector Total	*26.5*	*54.1*	*26.3*	*106.9*
Total Programs	**63.7**	**91.3**	**64.6**	**219.6**
Supporting Initiatives				
Public Awareness	7.4	7.5	7.6	22.5
Indirect and Portfolio Enabling	7.1	7.4	7.5	21.9
Supporting Initiatives Total	**14.6**	**14.9**	**15.0**	**44.4**
Total Programs, Rates & Supporting Initiatives	**78.7**	**106.6**	**80.1**	**265.4**
Codes and Standards	**5.2**	**5.3**	**5.4**	**16.0**
Capacity Focused DSM	**6.9**	**4.3**	**0.0**	**11.1**
PORTFOLIO TOTAL	**90.8**	**116.2**	**85.5**	**292.6**
PORTFOLIO TOTAL less TMP	**90.8**	**89.1**	**85.5**	**265.4**

Table A-2 BC Hydro Incentive Costs ($ million)

	Forecast F2020	Forecast F2021	Forecast F2022	Total: F2020-F2022
Rate Structures				
Residential Inclining Block Rate	0.0	0.0	0.0	0.0
General Service Rate	0.0	0.0	0.0	0.0
Transmission Service Rate	0.0	0.0	0.0	0.0
Total Rate Structures	**0.0**	**0.0**	**0.0**	**0.0**
DSM Programs				
Residential Sector				
Low Income	3.7	4.7	5.7	14.1
Non Integrated Areas	0.6	0.8	0.8	2.1
Retail	0.7	0.7	0.7	2.0
Home Renovation Rebate	3.2	3.4	3.6	10.2
Residential Energy Management Activities	0.6	0.6	0.5	1.7
Residential Sector Total	*8.7*	*10.2*	*11.2*	*30.1*
Commercial Sector				
LEM-C	5.5	5.4	5.4	16.4
New Construction	2.9	1.7	1.5	6.0
Commercial Energy Management Activities	3.7	3.5	3.5	10.7
Commercial Sector Total	*12.1*	*10.6*	*10.4*	*33.1*
Industrial Sector				
LEM-I	14.3	14.4	13.9	42.6
Thermo-Mechanical Pulp	0.0	27.2	0.0	27.2
Industrial Energy Management Activities	5.5	5.6	5.7	16.8
Industrial Sector Total	*19.8*	*47.2*	*19.6*	*86.6*
Total Programs	**40.6**	**68.0**	**41.2**	**149.8**
Supporting Initiatives				
Public Awareness	0.0	0.0	0.0	0.0
Indirect and Portfolio Enabling	0.0	0.0	0.0	0.0
Supporting Initiatives Total	**0.0**	**0.0**	**0.0**	**0.0**
Total Programs, Rates & Supporting Initiatives	**40.6**	**68.0**	**41.2**	**149.8**
Codes and Standards	**0.0**	**0.0**	**0.0**	**0.0**
Capacity Focused DSM	**2.5**	**2.0**	**0.0**	**4.5**
PORTFOLIO TOTAL	**43.2**	**70.0**	**41.2**	**154.3**
PORTFOLIO TOTAL less TMP	**43.2**	**42.8**	**41.2**	**127.1**

Table A-3 BC Hydro Non-Incentive Costs ($ million)

	Forecast F2020	Forecast F2021	Forecast F2022	Total: F2020-F2022
Rate Structures				
Residential Inclining Block Rate	0.0	0.0	0.0	0.0
General Service Rate	0.0	0.0	0.0	0.0
Transmission Service Rate	0.5	0.5	0.5	1.4
Total Rate Structures	**0.5**	**0.5**	**0.5**	**1.4**
DSM Programs				
Residential Sector				
Low Income	2.1	2.2	2.1	6.4
Non Integrated Areas	0.7	0.7	0.7	2.0
Retail	1.5	1.4	1.5	4.3
Home Renovation Rebate	1.1	0.9	1.0	3.0
Residential Energy Management Activities	4.3	4.3	4.5	13.1
Residential Sector Total	*9.6*	*9.5*	*9.8*	*28.9*
Commercial Sector				
LEM-C	3.5	3.7	3.7	10.9
New Construction	0.8	0.7	0.5	2.0
Commercial Energy Management Activities	2.5	2.6	2.6	7.7
Commercial Sector Total	*6.8*	*7.0*	*6.9*	*20.6*
Industrial Sector				
LEM-I	4.0	4.1	4.0	12.0
Thermo-Mechanical Pulp	0.0	0.0	0.0	0.0
Industrial Energy Management Activities	2.7	2.7	2.8	8.2
Industrial Sector Total	*6.7*	*6.8*	*6.7*	*20.3*
Total Programs	**23.1**	**23.3**	**23.4**	**69.8**
Supporting Initiatives				
Public Awareness	7.4	7.5	7.6	22.5
Indirect and Portfolio Enabling	7.1	7.4	7.5	21.9
Supporting Initiatives Total	**14.6**	**14.9**	**15.0**	**44.4**
Total Programs, Rates & Supporting Initiatives	**38.1**	**38.6**	**38.9**	**115.6**
Codes and Standards	**5.2**	**5.3**	**5.4**	**16.0**
Capacity Focused DSM	**4.3**	**2.3**	**0.0**	**6.6**
PORTFOLIO TOTAL	**47.6**	**46.2**	**44.3**	**138.2**
PORTFOLIO TOTAL less TMP	**47.6**	**46.2**	**44.3**	**138.2**

Table A-4 New Incremental Energy Savings at Customer Meter (GWh/yr)

	Forecast F2019[1]		Forecast F2020	Forecast F2021	Forecast F2022
	Per F2017-F2019 RRA	Updated			
Codes and Standards					
Residential	*197*	*261*	238	246	150
Commercial	*110*	*126*	107	153	125
Industrial	*9*	*11*	12	12	7
Total Codes and Standards	**316**	**398**	**356**	**411**	**282**
Rate Structures					
Residential Inclining Block Rate	*9*	*0*	0	0	0
General Service Rate	*0*	*0*	0	0	0
Transmission Service Rate	*114*	*117*	117	118	114
Total Rate Structures	**123**	**117**	**117**	**118**	**114**
DSM Programs					
Residential Sector	-				
Low Income	*3*	*6*	9	9	9
Non Integrated Areas	*0*	*0*	0	1	1
Retail	*4*	*6*	6	5	5
Home Renovation Rebate	*5*	*7*	8	8	9
Residential Energy Management Activities	*19*	*17*	13	13	12
Residential Sector Total	*31*	*36*	*36*	*36*	*36*
Commercial Sector	-				
LEM-C	*45*	*42*	51	47	39
New Construction	*5*	*10*	8	5	5
Commercial Energy Management Activities[2]	*n/a*	*n/a*	n/a	n/a	n/a
Commercial Sector Total	*50*	*53*	*59*	*52*	*44*
Industrial Sector	-				
LEM-I	*85*	*130*	132	136	92
Thermo-Mechanical Pulp	*131*	*102*	0	100	0
Industrial Energy Management Activities[2]	*n/a*	*n/a*	n/a	n/a	n/a
Industrial Sector Total	*215*	*232*	*132*	*236*	*92*
Total Programs	**296**	**321**	**227**	**324**	**172**
PORTFOLIO TOTAL	**736**	**836**	**700**	**853**	**568**
PORTFOLIO TOTAL less TMP	**605**	**733**	**700**	**753**	**568**

1. The purposes for showing the two fiscal 2019 columns above are: to have on record what the expected new incremental energy savings for fiscal 2019 are as per the Fiscal 2017 to Fiscal 2019 RRA DSM Plan. This will facilitate variance explanations of new incremental energy savings (actuals vs plan) in BC Hydro's year-end Report on Demand-Side Management Activities for fiscal 2019. The Updated Forecast of new incremental savings for fiscal 2019 is BC Hydro's view of expected savings, which was developed at the same time as the balance of the DSM Plan forecast.

2 Energy Management Activities enable and support the energy savings captured under other programs in the commercial and industrial sectors.

Table A-5 New Incremental Capacity Savings at Customer Meter (MW)

	Forecast F2020	Forecast F2021	Forecast F2022
Codes and Standards			
Residential	62	65	37
Commercial	15	21	16
Industrial	1	1	1
Total Codes and Standards	**79**	**88**	**54**
Rate Structures			
Residential Inclining Block Rate	0	0	0
General Service Rate	0	0	0
Transmission Service Rate	14	14	13
Total Rate Structures	**14**	**14**	**13**
DSM Programs			
Residential Sector			
Low Income	3	2	3
Non Integrated Areas	0	0	0
Retail	2	2	2
Home Renovation Rebate	3	3	3
Residential Energy Management Activities	3	3	3
Residential Sector Total	*10*	*10*	*10*
Commercial Sector			
LEM-C	8	7	6
New Construction	1	1	1
Commercial Energy Management Activities	n/a	n/a	n/a
Commercial Sector Total	*9*	*8*	*7*
Industrial Sector			
LEM-I	16	16	11
Thermo-Mechanical Pulp	0	12	0
Industrial Energy Management Activities	n/a	n/a	n/a
Industrial Sector Total	*16*	*28*	*11*
Total Programs	**35**	**46**	**28**
PORTFOLIO TOTAL	**128**	**147**	**95**
PORTFOLIO TOTAL less TMP	**128**	**136**	**95**

Note: Energy Management Activities enable and support the capacity savings captured under other programs in the commercial and industrial sectors.

Table A-6 Customer Bill Savings ($ million)

	Forecast F2020	Forecast F2021	Forecast F2022	Cumulative Total: F2020-F2022
Rate Structures				
Residential Inclining Block Rate	0	0	0	0
General Service Rate	0	0	0	0
Transmission Service Rate	7	15	17	39
Total Rate Structures	**7**	**15**	**17**	**39**
DSM Programs				
Residential Sector				
Low Income	1	2	3	5
Non Integrated Areas	0	0	0	0
Retail	0	1	2	3
Home Renovation Rebate	1	2	3	6
Residential Energy Management Activities	1	2	4	7
Residential Sector Total	*3*	*7*	*11*	*21*
Commercial Sector				
LEM-C	3	7	12	22
New Construction	0	1	1	3
Commercial Energy Management Activities	n/a	n/a	n/a	0
Commercial Sector Total	*3*	*8*	*13*	*25*
Industrial Sector				
LEM-I	7	16	20	43
Thermo-Mechanical Pulp	0	3	7	10
Industrial Energy Management Activities	n/a	n/a	n/a	0
Industrial Sector Total	*7*	*19*	*27*	*53*
Total Programs	**12**	**35**	**52**	**99**
PORTFOLIO TOTAL	**20**	**49**	**68**	**138**
PORTFOLIO TOTAL less TMP	**20**	**46**	**62**	**128**

Table A-7 Benefit Cost Ratios[1]

	LRMC ($105 per MWh)		Market Price ($30 per MWh)
	Modified Total Resource Cost Test	**Total Resource Cost Test excluding NEBs**	**Utility Cost Test**
Rate Structures			
Residential Inclining Block Rate	n/a	n/a	n/a
General Service Rate	n/a	n/a	n/a
Transmission Service Rate	1.4	1.4	11.1
Total Rate Structures	**1.4**	**1.4**	**11.1**
DSM Programs			
Residential Sector			
Low Income	3.5	2.7	0.9
Non Integrated Areas	2.2	1.8	1.8
Retail	6.0	6.3	2.0
Home Renovation Rebate	1.9	1.5	2.3
Residential Sector Total	*2.6*	*2.1*	*1.6*
Commercial Sector			
LEM-C	4.0	2.4	2.5
New Construction	3.0	2.0	1.5
Commercial Sector Total	*3.8*	*2.3*	*2.2*
Industrial Sector			
LEM-I	4.4	3.1	1.8
Thermo-Mechanical Pulp	2.7	2.7	1.2
Industrial Sector Total	*3.9*	*3.0*	*1.6*
Total Programs	**3.6**	**2.6**	**1.7**
Energy Management Activities	n/a	n/a	n/a
Supporting Initiatives	n/a	n/a	n/a
Codes & Standards	n/a	n/a	n/a
PORTFOLIO TOTAL[2]	**2.5**	**1.9**	**1.1**

Notes:
[1] Benefit-cost ratios are based on expenditures and energy savings from fiscal 20 to fiscal 22 activities.
[2] Energy management activities, supporting initiatives costs and codes and standards costs are included at the portfolio level. Capacity focused DSM is not included in cost-effectiveness calculations.

Table A-8 Levelized Costs ($/MWh)[1]

	Gross Levelized Costs		Non-Electricity Benefits		Natural Gas Benefits		Capacity Benefits (Generation)		Capacity Benefits (Transmission and Distribution)		Net Levelized Costs	
	Total Resource Cost Test	Utility Cost Test	Total Resource Cost Test	Utility Cost Test	Total Resource Cost Test	Utility Cost Test	Total Resource Cost Test	Utility Cost Test	Total Resource Cost Test	Utility Cost Test	Total Resource Cost Test	Utility Cost Test
Rate Structures												
Residential Inclining Block Rate	n/a	n/a	n/a	n/a	n/a	$0	n/a	n/a	n/a	n/a	n/a	n/a
General Service Rate	n/a	n/a	n/a	n/a	n/a	$0	n/a	n/a	n/a	n/a	n/a	n/a
Transmission Service Rate	$80	$3	$0	$0	$0	$0	-$5	-$5	-$2	-$2	$73	-$4
Total Rate Structures	**$80**	**$3**	**$0**	**$0**	**$0**	**$0**	**-$5**	**-$5**	**-$2**	**-$2**	**$73**	**-$4**
DSM Programs												
Residential Sector												
Low Income	$51	$65	-$54	$0	$3	$0	-$24	-$24	-$4	-$4	-$29	$36
Non Integrated Areas	$174	$175	-$58	$0	$0	$0	$0	$0	$0	$0	$117	$175
Retail	$22	$31	-$2	$0	$3	$0	-$25	-$25	-$4	-$4	-$6	$2
Home Renovation Rebate	$109	$32	-$8	$0	-$13	$0	-$35	-$35	-$5	-$5	$47	-$8
Residential Sector Total	*$72*	*$46*	*-$23*	*$0*	*-$4*	*$0*	*-$28*	*-$28*	*-$5*	*-$5*	*$12*	*$13*
Commercial Sector												
LEM-C	$51	$19	-$72	$0	-$3	$0	-$12	-$12	-$2	-$2	*-$39*	*$4*
New Construction	$73	$31	-$19	$0	-$23	$0	-$12	-$12	-$2	-$2	*$17*	*$16*
Commercial Sector Total	*$55*	*$20*	*-$64*	*$0*	*-$6*	*$0*	*-$12*	*-$12*	*-$2*	*-$2*	*-$30*	*$6*
Industrial Sector												
LEM-I	$38	$23	-$49	$0	$0	$0	-$8	-$8	-$2	-$2	-$22	$12
Thermo-Mechanical Pulp	$43	$32	$0	$0	$0	$0	-$7	-$7	-$2	-$2	$34	$23
Industrial Sector Total	*$39*	*$25*	*-$36*	*$0*	*$0*	*$0*	*-$8*	*-$8*	*-$2*	*-$2*	-$7	$15
Total Programs	**$49**	**$27**	**-$42**	**$0**	**-$2**	**$0**	**-$13**	**-$13**	**-$2**	**-$2**	**-$11**	**$12**
Energy Management Activities	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Supporting Initiatives	n/a	n/a	n/a	n/a	n/a	$0	n/a	n/a	n/a	n/a	n/a	n/a
Codes & Standards	n/a	n/a	n/a	n/a	n/a	$0	n/a	n/a	n/a	n/a	n/a	n/a
PORTFOLIO TOTAL[2]	**$67**	**$42**	**-$37**	**$0**	**-$2**	**$0**	**-$13**	**-$13**	**-$2**	**-$2**	**$14**	**$27**

[1] Levelized costs are based on expenditures and energy savings from fiscal 2020 to fiscal 2022 activities

[2] Energy management activities, supporting initiatives costs and codes and standards costs are included at the portfolio level. Capacity focused DSM is not included in cost-effectiveness calculations.

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Appendix X

Appendix B

Portfolio-Wide Assumptions

Timeframe for DSM Plan Analysis	Fiscal 2020-fiscal 2022: Aligns with the Annual Plan.
Inflation	2.0 per cent.
Discount Rates	6 per cent nominal and 4 per cent real, representing BC Hydro's corporate discount rates.
Avoided Costs	**Electric energy:** • Long Run Marginal Cost: $105 per MWh (Fiscal 2018 $) • Market Price: $30/MWh (Fiscal 2018 $) over a 15-year period from fiscal 2020 to fiscal 2034 **Generation capacity:** • Fiscal 2020 to fiscal 2022: $38 per kW-year (Fiscal 2018 $) • Fiscal 2023 to fiscal 2031: $60 per kW-year (Fiscal 2018 $) • Fiscal 2031 onwards: $123 per kW-year (Fiscal 2018 $) **Bulk transmission capacity:** • $0 per kW-year (Fiscal 2018 $) **Regional transmission and substation capacity:** • $13 per kW-year (Fiscal 2018 $) **Distribution capacity:** • $1 per kW-year (Fiscal 2018 $) **Natural gas:** • BC Hydro's forecast of wholesale natural gas prices at Sumas, or for the purposes of the modified TRC test, 100 per cent of the long-run marginal cost of electricity, converted to GJ.
Rates	The following BC Hydro rates were used to calculate customer bill savings and lost revenues: • Residential Inclining Block; • Small General Service; • Medium General Service; • Large General Service; and • Transmission Service.
Line Losses	Avoided electric energy and generation capacity costs are valued at the Lower Mainland, while avoided transmission and distribution capacity costs are valued in the regions. This requires an adjustment for line losses between customers and these points in the grid using the following values: • Distribution: 4 per cent; • Intra-regional transmission: 3 per cent; and • Inter-regional transmission: region-specific values.

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Appendix C

Detailed Breakdown of
Codes and Standard Savings

1 **Table C-1 New Incremental Electrical Savings**

Technologies	Legislation	F2020	F2021	F2022
General Service Lamps	PA 3	144	154	26
Ceiling Fans FA10	FA 10	-	-	-
Dishwashers	FA 13	1	1	1
Commercial Clothes Washers	FA 13	0	0	0
Ice Makers	FA 13	0	0	0
Torchieres	FA 10	0	0	0
Traffic & Ped Lights	FA 10	2	2	2
External Power Supplies	FA 11	-	-	-
Standby Power	FA 11	6	5	3
Televisions	PA 4	22	6	5
Freezers BCA5	FA 13	4	4	3
Refrigerators BCA5	FA 13	10	10	9
Dishwashers BCA5	FA 13	3	3	4
Clothes Washers BCA5	FA 13	23	18	17
Electric WH	PA 3	4	3	3
Windows	PA 2	4	4	4
Commercial Refrigeration	FA 11	2	2	2
Large AC	FA 11	1	1	1
SPVAC	FA 11	0	0	0
Dry-type Transformers	FA 11	1	1	1
Fluorescent Ballasts PA2	PA 2	-	-	-
Industrial Large Motors	PA 3	6	6	6
DTAs	FA 11	-	-	-
GSL Fluorescent Lamps	FA 13	12	12	12
Fluorescent Ballast	FA 13	5	5	5
STBs 2012	PA 6	-	-	-
BCBC - Commercial	BCBC	15	18	18
VBBL - Commercial	VBBL	3	4	4
BCBC - Residential	BCBC	22	22	29
VBBL - Residential	VBBL	1	1	1
BC Step Code	BCSC	1	1	1
PTAC	FA 13	3	2	2
Incandescent Reflector Lamps	FA 13	2	2	1
MH Lamp Ballasts	FA 14	-	-	-
Pre-rinse Spray Valves	FA 14	-	7	7
GSL 45lm W	PA 6	-	2	3
Room AC	FA 13	0	0	0
Small Battery Chargers	PA 5	30	23	21
MR16 Lamps	PA 6	-	15	11
Computers and Small Servers	PA 7		14	19
VBBL - Com Tenant Improvements	VBBL	10	10	10
Heat Pump	PA 6	1	1	1
External Power Supplies	FA 14	-	-	-
Microwave Ovens	FA 14	-	-	-

Technologies	Legislation	F2020	F2021	F2022
Dehumidifiers	FA 14	-	-	-
Large Battery Chargers	FA 14	-	0	0
Large ACs and HPs	FA 14	-	2	2
PTAC	FA 14	-	0	0
Commercial Refrigeration	FA 14	-	16	18
Walk-in Coolers and Freezers	FA 14	-	3	3
Dry-type Transformers	FA 14	-	0	0
Small Motors	FA 14	-	11	11
Ceiling Fans	FA 14	-	-	-
Total		356	411	282

Description
PA = Provincial Amendment
FA = Federal Amendment
BCBC = BC Building Code
VBBL = Vancouver Building Bylaw

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Revenue Requirements Application

Appendix Y

Low Carbon Electrification Program

PUBLIC

LOW CARBON ELECTRIFICATION PROGRAM

Conservation and Energy Management

February 2019

Contents

BC Hydro
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1.0 Overview

In this appendix, we describe the Low Carbon Electrification (**LCE**) Demand-Side Management (**DSM**) Projects/Programs that we have undertaken and plan to undertake over fiscal 2019, fiscal 2020 and fiscal 2021. All of our LCE DSM Projects/Programs are within one or more class of undertakings prescribed under the Greenhouse Gas Reduction (Clean Energy) Regulation, issued under section 18 of the *Clean Energy Act*.

1.1 Greenhouse Gas Reduction Regulation

Section 18 of the *Clean Energy Act* requires the British Columbia Utilities Commission (the BCUC) to allow BC Hydro to collect sufficient revenue to recover costs incurred for prescribed undertakings. Section 4 of the Greenhouse Gas Reduction (Clean Energy) Regulation (B.C. Reg. 102/2012) (**GGRR**) defines eight classes of electrification prescribed undertakings corresponding to sections 4(2), 4(3)(a)(i), 4(3)(a)(ii), 4(3)(b)(i), 4(3)b)(ii), 4(3)(c), 4(3)(d) and 4(3)(e). Undertakings are in a class of undertakings defined in subsections 4(3)(a) to 4(3)(b) of the GGRR if they satisfy a cost-effectiveness test defined in subsection 4(1) of the GGRR.

The eight new classes of electrification undertakings prescribed by section 4 of the GGRR can be divided into two broad categories: those that are program based, similar to BC Hydro's demand-side management programs,[1] and those that are infrastructure based.[2] BC Hydro refers to its undertakings that fall within one of the classes in the former category as Low Carbon Electrification (**LCE**) Demand-Side Management (**DSM**) Projects/Programs, and to its undertakings that fall within one of the classes in the latter category as LCE Infrastructure Projects.

1.2 Scope of Appendix Y

Appendix Y focuses only on LCE DSM Projects/Programs BC Hydro has undertaken, or will undertake, that are in one or more classes of undertakings defined in sections 4(3)(a), 4(3)(b), 4(3)(c), and 4(3)(d) of the GGRR.

Since the Previous Application, there have been a number of developments on LCE DSM Projects/Programs. In July 2018, BC Hydro submitted its Fiscal 2018 Greenhouse Gas

1 Being the classes of undertaking prescribed by subsections 4(3)(a)(i); 4(3)(a)(ii); 4(3)(b)(i); 4(3)(b)(ii); 4(3)(c) and 4(3)(d) of the GGRR.
2 Being the classes of undertaking prescribed by subsections 4(2) and 4(3)(e) of the GGRR.

Reduction Regulation Annual Report (**Fiscal 2018 Annual Report**), a copy of which is provided as Appendix BB. In section 2.0 below, BC Hydro provides further details on LCE DSM Projects/Programs which were previously introduced in the Fiscal 2018 Annual Report and are in one or more class of undertakings defined in sections 4(3)(a) and 4(3)(c) of the GGRR. For the purpose of this document, these programs are referred to as “LCE Initial Projects”. Section 2.0 also provides past and forecast expenditures for these projects.

In section 3.0 BC Hydro provides details on a new LCE DSM Projects/Program, which has been developed following the Fiscal 2018 Annual Report. For the purpose of this document, this new program is referred to as the “BC Hydro LCE Program”. Section 3.0 also provides expenditures for components of the program, including forecast expenditures for the test period.

In section 4.0 BC Hydro will demonstrate the cost-effectiveness of its LCE DSM Projects/Programs that are in the classes of undertakings defined under section 4(3)(a) and 4(3)(b) of the GGRR.

1.3 Overview of LCE DSM Projects/Programs

Beginning in fiscal 2018, BC Hydro moved forward with the Initial LCE Projects to assess and support immediate low carbon electrification opportunities among our customers. These projects are within one (or more) class of undertakings defined in subsections 4(3)(a) and 4(3)(c). These Initial LCE Projects also

- helped us gain a greater understanding of the technology, market, and barriers that customers and BC Hydro would face when developing low carbon electrification options; and
- provided BC Hydro the ability to act early and capture time-sensitive opportunities that could help inform the development of a broader low carbon electrification plan.

The Initial LCE Projects were introduced in the Fiscal 2018 Annual Report. Those included projects where BC Hydro incurred and recorded actual costs in fiscal 2018. Also included in the Fiscal 2018 Annual Report was a forecast of expenditures related to other projects where BC Hydro made preliminary funding commitments but there were no actual costs for those projects in fiscal 2018. In section 2.0 and Table 2-1 and Table 4-1, BC Hydro provides further information on the Initial LCE Projects where BC Hydro will expect to incur expenditures in fiscal 2019 and beyond.

In fiscal 2019, Government launched the EfficiencyBC program to reduce greenhouse gas emissions in the province. This $24 million, Government funded program provides financial incentives to help households and businesses save energy and reduce greenhouse gas emissions by switching to high-efficiency heating equipment and making building-envelope improvements. BC Hydro is delivering the fuel switching component of the EfficiencyBC program on Government's behalf, within our service territory. This component helps customers switch from fossil fuels to our clean electricity. The expenditures associated with implementing the EfficiencyBC program are borne by Government and not BC Hydro ratepayers.

Coinciding with delivering the fuel switching component of the EfficiencyBC program and further to the Initial LCE Projects, BC Hydro has developed the BC Hydro LCE Program, a new BC Hydro funded low carbon electrification program. The program has been coordinated to align with, and not overlap with, government funded greenhouse gas emissions reduction programs. Specifically, the BC Hydro LCE Program has been developed to reach customers not addressed by EfficiencyBC or by Government funded transportation programs. The BC Hydro LCE Program is described in section 3.0 and Table 3-1. The BC Hydro LCE Program has components that are within one or more class of undertakings defined by subsections 4(3)(a), 4(3)(b), 4(3)(c), and 4(3)(d) of the GGRR. As shown in Table 4-1 below, the undertakings in the classes defined in section 4(3)(a) and 4(3)(b) of the GGRR are cost-effective.

Should Government bring forward additional programs in the future that would overlap with activities planned or underway with funding from BC Hydro, we can make adjustments to our plans to ensure that any overlap is needed and by design.

BC Hydro expects to develop a future plan for low carbon electrification that is informed by the learning gained through the Initial LCE Projects and the BC Hydro LCE Program as well as Government's CleanBC Plan.

2.0 BC Hydro Funded Initial Low Carbon Electrification Projects

The Initial LCE Projects are in one or more class of undertakings defined in subsections 4(3)(a) and 4(3)(c). The details of these Initial LCE Projects are provided below.

Programs Under Subsection 4(3)(a)

- Customer Project 1 [redacted] and Project 2 [redacted] – [redacted]: BC Hydro provided funds to [redacted] to assist in the acquisition, installation, and use of equipment that uses electricity to power natural gas production, instead of the customer burning their own gas to power gathering, transport and processing operations.
- Customer Project 3 – Thompson Rivers University: BC Hydro provided funding to Thompson Rivers University to assist in the acquisition, installation, and use of equipment that uses electricity (electric boilers) instead of natural gas boilers in a new building.

Projects/Programs/Expenditures under subsection 4(3)(c)

In general, the projects/programs/expenditures within a class of undertakings defined in this subsection are for researching new applications of technologies that have not been proven in or adopted in BC, or are projects with specific customers researching technology applications where the learnings from the projects will inform future BC Hydro programs and customer opportunities.

- Project 4 - [redacted]: The focus of this project was to examine a portion of the customer's industrial process heating requirements and technology alternatives with the intent of determining if a viable fuel switching technology solution may exist specific for the customer. Process heating is typically supplied by natural gas, or propane. This work investigated if an opportunity existed to use electricity in place of fossil fuels for [redacted] and also potentially for other BC Hydro customers.
- Project 5 - [redacted]: The focus of this project was to enable the customer to have research completed by comparing two material handling options. The status quo option of using diesel fueled trucking was compared to options that would utilize electric conveying technology. The objective of the research was to determine whether the conveyor option is worth pursuing beyond the conceptual stage.

- Project 6 - [redacted]: The focus of this project was to examine technology alternatives for the customer to use electricity for [redacted] materials handling. The current materials handling method [redacted] involves use of diesel fueled equipment to remove the [redacted] from the [redacted], and [redacted] trucks (diesel fueled) to transport the [redacted] back into the [redacted]. The project examined a potential electrified system [redacted].
- Project 7 - Translink: Translink, along with the Centre for Urban Transit Research Innovation Consortium and BC Hydro, is conducting a pilot project which replaces four diesel buses with four electric-battery buses and two charging stations. The two year pilot project will evaluate the feasibility of technology using electric battery buses and charging stations on a broader basis.
- Project 8 - Vancouver Fraser Port Authority: This project focused on low carbon drayage and was the first phase of research into ways low carbon technologies could be introduced into the local heavy duty transportation network to reduce carbon emissions. Drayage referrers to transporting goods a short distance via ground freight.
- Project 9 - Integral Group Consulting: This research project consists of 6 individual buildings selected to represent a sampling of various building types, building code requirements, technologies, and studies the low carbon electrification opportunities that we may see come forward as implementation projects in these building types.
- Project 10 - Thompson Rivers University: The focus of this project is to research the potential of a five-Year “building by building” retrofit approach, considering a number of technologies that could lead to a new strategy to electrify building systems instead of using other sources of energy that produce more greenhouse gas emissions.
- Project 11 - Wildsight, with support from Columbia Basin Trust – This project is examining the feasibility of conducting a truck stop electrification pilot project in the Golden area. Truck stop electrification (**TSE**) technology allows those in the long haul trucking industry the opportunity to connect to the electrical grid rather than idling their truck engines while stopped or overnighting. Idle reduction saves significant diesel fuel combustion avoiding CO2 emissions.

Table 2-1 below outlines BC Hydro's expenditures for the Initial LCE Projects in each fiscal year, including the test period.

Table 2-1 – Expenditures for Initial LCE Projects

Initial LCE Projects		Expenditures ($ million) [3]					
GGRR Regulation Subsection	**Project**	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
4(3)(a)	Project 1	-	6.30	-	2.70	6.00	15.00
	Project 2	-	-	13.50	-	-	13.50
	Project 3	-	0.28	-	-	-	0.28
4(3)(c)	Project 4	0.01	-	-	-	-	0.01
	Project 5	-	0.07	-	-	-	0.07
	Project 6	0.00	-	-	-	-	0.00
	Project 7	-	0.50	-	-	-	0.50
	Project 8	0.07	-	-	-	-	0.07
	Project 9	-	0.09	-	-	-	0.09
	Project 10	-	0.06	-	-	-	0.06
	Project 11	-	0.00	-	-	-	0.00
	BC Hydro Program Staff Labour	0.12	-	-	-	-	0.12
Project Total		**0.21**	**7.30**	**13.50**	**2.70**	**6.00**	**29.71**

[3] Expenditure shown in Table 2-1 includes costs recorded in fiscal 2018, as well as expenditures forecast for projects which BC Hydro has made preliminary funding commitments.

3.0 BC Hydro LCE Program

The BC Hydro LCE Program, commenced in fiscal 2019, focuses on opportunities in industrial process, transportation, and new construction, and include components in one (or more) class of undertakings defined in subsections 4(3)(a), 4(3)(b), 4(3)(c), and 4(3)(d). A component of the BC Hydro LCE Program may be developed to focus on, for instance,

- Providing funds to enable energy management and audit services to our customers or educating and training customers regarding their energy use;
- Carrying out public awareness campaigns respecting energy use;
- Providing financial support to customers to assist them with the acquisition, installation and use of equipment that uses or affects the use of electricity;
- Providing funding to conduct research and pilot projects respecting technology that may enable our customers to use electricity; and
- Supporting standards making bodies in their development of standards respecting technologies that use electricity instead of other sources of energy.

The following Table 3-1 provides a high level overview of the components of the BC Hydro LCE Program and the relevant subsections of the GGRRs.

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Table 3-1 –Component Description of the BC Hydro LCE Program

Components	Detailed Description	GGRR Subsection
Energy Management Studies and Incentives	Studies and Assessments – BC Hydro provides funding toward studies and assessments to assist customers, or those who may become customers, to identify and develop project opportunities involving the acquisition, installation, or use of equipment that uses electricity instead of other sources of energy that produce more greenhouse gas emissions. Project Incentives - BC Hydro provides project incentive funding to reduce the cost of projects to assist customers, or those who may become customers, with the acquisition, installation, or use of equipment that uses electricity instead of other sources of energy that produce more greenhouse gas emissions. Funding is provided direct to customers or in some cases direct to persons who -design, manufacture, sell, install or in the course of operating a business, provide advice respecting equipment that uses or affects the use of electricity, -or design, construct, manage or, in the course of operating a business, provide advice respecting energy systems in building or facilities, -or design, construct or manage district energy systems.	4(3)(a), 4(3)(b)
Public Awareness Campaigns	BC Hydro carries out a set of activities that educate and increase public awareness respecting the use of electricity instead of other sources of energy that produce greenhouse gas emissions. These activities cover a variety of channels and leverage specific partners such as retailers and manufacturers who have existing channels available to them that, when combined with BC Hydro's support, can reach a wide cross-section of relevant customers	4(3)(a), 4(3)(b)
Research and Pilots	BC Hydro works with customers and provides funding toward the research and development of technology, or pilot projects, that may enable the customers to use electricity instead of other sources of energy that produce more greenhouse gas emissions.	4(3)(c)
Standards Enabler	BC Hydro works with standards making bodies such as various levels of government, who are responsible for land use, building codes, product and equipment standards, policies, bylaws, and community plans, to advance standards for technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions, or technologies that affect the use of electricity by other technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions.	4(3)(d)

Components	Detailed Description	GGRR Subsection
Education & Training	BC Hydro delivers education and training to the BC Hydro Alliance of Energy Professionals (Alliance) members to ensure they are educated with respect to energy use and greenhouse gas emissions as well as trained on the details of the BC Hydro LCE Program. The Alliance is a network of contractors, consulting engineers, distributors and registered experts that provide energy management solutions to our customers. This group designs, manufactures, sells, and installs equipment that uses or affects the use of electricity. BC Hydro leverages the Alliance members' ability to sell and promote products, services, and our programs to our customers to encourage them to use electricity instead of other source of energy that produce more greenhouse gas emissions.	4(3)(b)

Table 3-2 below outlines expenditures for the BC Hydro LCE Program components in each fiscal year, including the test period.

Table 3-2 – BC Hydro Funded Low Carbon Electrification Program Expenditures

BC Hydro LCE Program		Expenditures ($ million)					
GGRR Regulation Subsection	**Program Component**	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
4(3)(a), 4(3)(b)	Energy Management Studies and Incentives	-	1.51	3.10	7.00	2.49	14.11
4(3)(a)	Public Awareness	-	0.60	0.91	-	0.00	1.51
4(3)(b)	Education & Training	-	0.01	0.04	-	-	0.05
4(3)(c)	Research and Pilots	-	0.01	0.10	-	-	0.11
4(3)(d)	Standards Enabler	-	0.23	0.65	-	-	0.88
Program Total		**-**	**2.35**	**4.80**	**7.00**	**2.49**	**16.65**

4.0 Cost Effectiveness

As shown in Table 2-1 and Table 3-2 included in section 2.0 and section 3.0, respectively, BC Hydro has chosen to engage in undertakings that are within one (or more) class of undertakings defined in sections 4(3)(a), 4(3)(b), 4(3)(c) or 4(3)(d) of the GGRR. Undertakings are in a class of undertakings defined in section 4(3)(a) and 4(3)(b) of the GGRR if they meet the cost-effective test. The cost-effectiveness test requires that each undertaking that is an undertaking within the class of undertakings defined by subsections 4(3)(a) or 4(3)(b) of the GGRR have a positive net present value (**NPV**), with the measure of a program's NPV being that of all of the programs that fall within the class of undertakings described in subsections 4(3)(a) and 4(3)(b) of the GGRR. Specifically, benefits mean all revenues BC Hydro expects to earn as a result of implementing LCE projects/programs falling under subsections 4(3)(a) or 4(3)(b), less revenues that BC Hydro expects to earn from the sale of that electricity to export markets. Costs mean all the costs BC Hydro expects to incur to implement LCE projects/programs falling under subsections 4(3)(a) or 4(3)(b), including development and administration costs. Furthermore, the GGRR cost-effectiveness test is measured only at the time BC Hydro decides to carry out a projects/programs. There is no other cost-effectiveness test applicable to prescribed undertakings.

The Table 4-1 below shows the NPV of all BC Hydro's projects/programs prescribed under section 4(3)(a) and 4(3)(b) of the GGRR including BC Hydro's proposed low carbon electrification expenditures for fiscal 2020 and fiscal 2021. The NPV $134.7m indicates that these undertakings are cost-effective.

Table 4-1 – Cost Effectiveness

A	B	C	D	E		F		G	
GGRR	**Project/ Program/ Contract/ Expenditure**	**Expenditure ($ million)**	**Cost Effectiveness (F18 $million)**	**Additional Energy Consumption (MWh/year)**		**Additional Demand (MW)**		**Estimated GHG Emission Reductions (tonnes CO2e/year)**	
		Total	**GGRR NPV to 2030 (F2031)**	**Incremental**	**Cuml.**	**Incremental**	**Cuml.**	**Incremental**	**Cuml.**
4(3)(a)	Project 1	16.20	64.32	268,056	268,056	36.0	36.0	158,090	158,090
4(3)(a)	Project 2	13.50	110.20	223,380	491,436	30.0	66.0	131,742	289,832
4(3)(a)	Project 3	0.28	110.50	2,737	494,173	0.0	66.0	562	290,394
4(3)(a)(b)	BC Hydro LCE Program[4]	15.66	134.71	108,337	602,509	17.3	83.3	56,896	347,290
	Total	**45.64**	**134.71**	**602,509**	**602,509**	**83.3**	**83.3**	**347,290**	**347,290**

One of the legal consequences of BC Hydro's program or project being in a class of prescribed undertakings under section 18 of the *Clean Energy Act* is that BC Hydro is entitled to recover the costs of our electrification programs or projects in rates. The expenditures BC Hydro incurs in regard to its LCE DSM Projects/Programs are sought to be deferred to the DSM Regulatory Account in this application.

4 The BC Hydro LCE Program includes costs and benefits related to the class of undertakings defined in sections 4(3)(a) and 4(3)(b) of the GGRR.

Fiscal 2020 to Fiscal 2021

Revenue Requirements Application

Appendix Z

Annual DSM Reports to the BCUC

BC Hydro
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Fred James
Chief Regulatory Officer
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July 12, 2017

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
F2005/F2006 Revenue Requirements Application
Commission Decision: October 29, 2004; Directive 69 (page 201)
(AMENDED pursuant to 2006 Integrate Electricity Plan and
2006 Long-Term Acquisition Plan
Commission Decision: May 11, 2006; Directive 16 (pages 145 to 146)
2008 Long-Term Acquisition Plan
Commission Decision: July 27, 2009; Directive 36 (page 184))
F2017 Demand-Side Management Activities Annual Report

BC Hydro writes to provide its Report on Demand-Side Management Activities for the 12 months ending March 31, 2017.

For further information, please contact Geoff Higgins at 604-623-4121 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

(for) Fred James
Chief Regulatory Officer

cu/ma

Enclosure (1)

BC Hydro
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Report on Demand-Side Management Activities for Fiscal 2017

July 12, 2017

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1 Introduction

This BC Hydro annual report to the British Columbia Utilities Commission (**BCUC or Commission**) on Demand-Side Management (**DSM**) activities provides information on DSM expenditures, electricity savings, plan performance and mitigation measures for the 2017 fiscal year (**F2017**), which is the twelve months ending March 31, 2017. This annual report is filed in compliance with the following Commission Directives:

- Directive 69 from the Commission Decision on BC Hydro's F2005/F2006 Revenue Requirements Application (**F05/F06 RRA**);
- Directive 16 from the Commission Decision on BC Hydro's 2006 Integrated Electricity Plan and Long Term Acquisition Plan (**2006 IEP/LTAP**); and
- Directives 36 and 38 from the Commission decision on BC Hydro's 2008 LTAP.

Directive 69 of the F05/F06 RRA Decision directed BC Hydro "to provide information to the Commission for on-going review of Power Smart performance through:

- Executive Summaries of milestone evaluation reports and full final evaluation reports for each program;
- Semi-annual reports on DSM activities which, amongst others, will include:
  - ▶ detailed breakdown of OMA expenses related to support activities carried out within the Power Smart group and in other departments that support the Power Smart organization;
  - ▶ detailed description of the functions of portfolio level costs and how these costs are allocated to programs;
  - ▶ summaries of the overall performance of Power Smart with reference to program objectives; and
  - ▶ variances of fiscal year budgeted and actual deferred capital expenditures and explanation of variances."

Directive 16 of the 2006 IEP/LTAP Decision directed BC Hydro "to continue to file reports on DSM performance as described in Directive 69 of the F05/F06 RRA Decision included in Order No. G-96-04 and to file its Semi Annual Demand-Side Management Reports in the same format as the June 2005 Report with the following enhancements:

Provide annual and cumulative totals since program inception;

(i) Express these values on a per unit basis; and

(ii) Provide the benefit to cost ratios for the three DSM tests."

Directive 36 of the 2006 IEP/LTAP Decision directed BC Hydro to switch from semi-annual to annual DSM performance reports. Directive 38 from the same Decision directed BC Hydro to include in these reports:

> "metrics for each initiative, achievements in relation to milestones, and description of past or planned mitigation measures where warranted. These mitigation measures should include shifting program resources and alternative supply options for each program. Ongoing DSM performance reporting should demonstrate how BC Hydro is continuously pursuing DSM and that specific programs are cost-effective."

BC Hydro files its evaluation reports pursuant to Directive 69 of the F05/F06 RRA Decision separately. This annual report addresses the balance of Directives 69 and 16, as well as Directives 36 and 38 of the 2006 IEP/LTAP Decision.

2 Expenditures and Electricity Savings for Fiscal 2017

BC Hydro's DSM expenditures[1] in F2017 totalled $97.4 million while net incremental DSM electricity savings totalled 602 GWh/year. Expenditures were $16 million or 14 per cent below the F2017 DSM Plan presented in BC Hydro's Fiscal 2017 - Fiscal 2019 Revenue Requirements Application (**F2017-F2019 RRA**).

1 Comprising all DSM-related deferred operating expenditures. DSM operating expenditures are presented in Table 6 of this report.

Overall, net incremental electricity savings as shown in Table 1 were 3 GWh/year or 1 per cent above the DSM Plan.

Table 1 presents planned and actual DSM expenditures and net incremental electricity savings in F2017.

Table 1 Expenditures and Net Incremental Electricity Savings for F2017

	Expenditures[1]				Net Incremental Electricity Savings			
	Plan[2]	Actual	Variance		Plan[2]	Actual[3]	Variance	
	$ 000	$ 000	$ 000	%	GWh/yr	GWh/yr	GWh/yr	%
Codes and Standards								
Residential	-	-	-	-	212	240	28	13%
Commercial	-	-	-	-	63	63	(0)	(0%)
Industrial	-	-	-	-	6	6	(0)	(0%)
Total Codes and Standards	4,740	5,057	317	7%	282	309	28	10%
Rate Structures					-			
Residential Inclining Block Rate	500	527	27	5%	8	8	(0)	(0%)
General Service Rate	-	-	-	-	-	-	-	-
Transmission Service Rate	747	265	(482)	(65%)	15	(33)	(47)	(326%)
Total Rate Structures	1,247	792	(455)	(36%)	23	(25)	(47)	(209%)
DSM Programs								
Residential Sector								
Behaviour	3,933	2,176	(1,757)	(45%)	15	15	(0)	(1%)
Refrigerator Buy-back	-	0	0	-	-	-	-	-
Low Income	2,535	2,890	355	14%	3	4	1	48%
New Home	-	(128)	(128)	-	-	-	-	-
Retail	3,408	4,658	1,250	37%	15	27	12	81%
Home Energy Retrofit Offer	2,425	2,246	(178)	(7%)	4	4	(0)	(6%)
Sector Enabling Activities	834	677	(157)	(19%)	n/a	n/a	n/a	n/a
Residential Sector Total	13,135	12,519	(617)	(5%)	37	50	13	35%
Commercial Sector								
Leaders in Energy Management - Commercial	31,348	25,050	(6,299)	(20%)	106	84	(22)	(21%)
New Construction	11,549	8,781	(2,768)	(24%)	21	18	(3)	(13%)
Sector Enabling Activities	1,000	682	(318)	(32%)	n/a	n/a	n/a	n/a
Commercial Sector Total	43,898	34,513	(9,385)	(21%)	127	102	(25)	(20%)
Industrial Sector								
Leaders in Energy Management - Transmission	16,081	14,365	(1,716)	(11%)	106	142	36	34%
Thermo-Mechanical Pulp	-	133	133	-	-	-	-	-
Leaders in Energy Management - Distribution	9,779	8,152	(1,626)	(17%)	25	24	(1)	(4%)
Load Displacement	-	-	-	-	-	-	-	-
Sector Enabling Activities	814	523	(291)	(36%)	n/a	n/a	n/a	n/a
Industrial Sector Total	26,674	23,173	(3,501)	(13%)	131	166	35	27%
Total Programs	**83,707**	**70,204**	**(13,502)**	**(16%)**	**295**	**318**	**23**	**8%**
Supporting Initiatives								
Public Awareness	6,872	6,799	(73)	(1%)	-	-	-	-
Indirect and Portfolio Enabling	7,166	6,178	(988)	(14%)	-	-	-	-
Supporting Initiatives Total	**14,037**	**12,977**	**(1,061)**	**(8%)**	-	-	-	-
ENERGY EFFICIENCY PORTFOLIO TOTAL	**103,732**	**89,031**	**(14,701)**	**(14%)**	-	-	-	-
Capacity Focused DSM	9,988	8,377	(1,611)	(16%)	-	-	-	-
PORTFOLIO TOTAL, EE & CF DSM	**113,720**	**97,408**	**(16,312)**	**(14%)**	**599**	**602**	**3**	**1%**

Notes:

1 Including all DSM-related deferred operating expenditures that are relevant for DSM cost-effectiveness.

2 Plan figures are from BC Hydro's F2017-F2019 RRA, Appendix W.

3 Reported savings from codes and standards and residential inclining block and general service rate structures are based on planned estimates as well as evaluated results.

The following corresponds to the information provided in Table 1 and are explanations for the above variances:

Codes and Standards	
Residential	Expenditures were approximately on plan. Electricity savings were above plan due to an adjustment of the allocation of savings between codes and standards and other lighting-related DSM programs as a result of the general service incandescent lamps regulation by the federal government.
Commercial	
Industrial	
Rate Structures	
Residential Inclining Block Rate	Expenditures were approximately on plan. Electricity savings were on plan.
General Service Rate	No further conservation is forecast from the general service rate as BC Hydro has revised its conservation forecast to zero due to the outcomes of the F2014 LGS/MGS evaluation report.
Transmission Service Rate	Expenditures were below plan due to the timing of the Transmission Service Rate evaluation, deferral of consultation activities for phase two of the Rate Design Application and the ability to move forward with a lower cost solution for invoice and billing data centralization. Electricity savings were below plan primarily due to a reduction in incremental customer self-generation due to F2016 customer self-generation actuals being higher than planned.
DSM Programs	
Residential Sector	
Behaviour	Expenditures were below plan due primarily to delays in a planned project to enhance energy insights provided to customers. Electricity savings were approximately on plan.
Refrigerator Buy-Back	The program has ended per the new DSM Plan in the F2017-F2019 RRA.
Low Income	Expenditures and electricity savings were above plan due to higher than planned participation in the Energy Saving Kit and Energy Conservation Assistance portions of the program offer. This was largely due to strong promotional campaigns as well as leads generated through the BC Hydro call centre resulting in higher volumes of lower cost Energy Savings Kits.
New Home	The program has ended per the new DSM Plan in the F2017-F2019 RRA.
Retail	Expenditures and electricity savings were above plan due to the success of the lighting campaign.
Home Energy Retrofit Offer	Expenditures and electricity savings were approximately on plan.
Sector Enabling Activities	Expenditures were below plan due to planned activities being deferred or cancelled.
Commercial Sector	
Leaders in Energy Management - Commercial	Expenditures and electricity savings were below plan due to customer decisions to delay or cancel projects.
New Construction	Expenditures and electricity savings were below plan due to customer decisions to delay or cancel projects.
Sector Enabling Activities	Expenditures were below plan due to planned activities being deferred or cancelled.

Industrial Sector	
Leaders in Energy Management – Transmission	Expenditures were below plan due to a number of incented projects being deferred by customers to F2018. Electricity savings were above plan due to cost effective energy savings related to strategic energy management activities.
Thermo-Mechanical Pulping	Expenditures were for studies to support the Thermo-Mechanical Pulping projects that will be implemented in future years.
Leaders in Energy Management – Distribution	Expenditures were below plan due to projects being cancelled or deferred by customers and a slower launch on strategic energy management initiatives targeting small and medium businesses. Electricity savings were approximately on plan.
Load Displacement	The program has ended per the new DSM Plan in the F2017-F2019 RRA.
Sector Enabling Activities	Expenditures were below plan due to planned activities being deferred or cancelled.
Capacity Focused DSM	Expenditures are below plan due to project delays and project cost efficiencies related to selected initiatives as well as lower volume than planned within the industrial load curtailment pilot.
Total Programs	Expenditures were below plan primarily due to projects not completing as planned in the commercial sector. Electricity savings were above plan primarily due to the success of strategic energy management activities in the Industrial Leaders in Energy Management - Transmission program and Residential Retail program.
Supporting Initiatives	
Public Awareness	Expenditures were approximately on plan.
Indirect and Portfolio Enabling	Expenditures were below plan primarily due to lower volume of IT support and enhancements required.
Portfolio Total	Expenditures were below plan primarily due to customer decisions to delay or cancel projects in the commercial sector. Electricity savings were approximately on plan due to the success of strategic energy management activities in the Industrial Leaders in Energy Management - Transmission program and Residential Retail program.

3 Expenditures to Date

BC Hydro's DSM expenditures from F2016 through F2017 totalled $242.6 million. Table 2 presents DSM expenditures from April 1, 2015 to March 31, 2017.[2]

Table 2 Expenditures since F2016

	F2016 ($ 000)	F2017 ($ 000)	Total ($ 000)
Codes and Standards			
Residential	-	-	-
Commercial	-	-	-
Industrial	-	-	-
Total Codes and Standards	**4,688**	**5,057**	**9,745**
Rate Structures			
Residential Inclining Block Rate	506	527	1,033
General Service Rate	487	-	487
Transmission Service Rate	309	265	574
Total Rate Structures	**1,302**	**792**	**2,094**
DSM Programs			
Residential Sector			
Behaviour	3,236	2,176	5,412
Refrigerator Buy-back	1,188	0	1,188
Low Income	2,425	2,890	5,315
New Home	1,255	(128)	1,127
Retail	4,712	4,658	9,370
Home Energy Retrofit Offer	2,241	2,246	4,488
Sector Enabling Activities	973	677	1,650
Residential Sector Total	16,030	12,519	28,549
Commercial Sector			
Leaders in Energy Management - Commercial	25,159	25,050	50,209
New Construction	7,360	8,781	16,140
Sector Enabling Activities	1,089	682	1,772
Commercial Sector Total	33,609	34,513	68,121
Industrial Sector			
Leaders in Energy Management - Transmission	18,771	14,365	33,136
Thermo-Mechanical Pulp	19,657	133	19,789
Leaders in Energy Management - Distribution	10,897	8,152	19,049
Load Displacement	14,481	-	14,481
Sector Enabling Activities	968	523	1,491
Industrial Sector Total	64,774	23,173	87,947
Total Programs	**114,412**	**70,204**	**184,617**
Supporting Initiatives			
Public Awareness	8,838	6,799	15,637
Indirect and Portfolio Enabling	7,278	6,178	13,455
Supporting Initiatives Total	**16,116**	**12,977**	**29,092**
ENERGY EFFICIENCY PORTFOLIO TOTAL	**136,517**	**89,031**	**225,548**
Capacity Focused DSM	8,644	8,377	17,022
PORTFOLIO TOTAL, EE & CF DSM	**145,162**	**97,408**	**242,570**

2 Comprising all DSM deferred operating expenditures that are relevant for DSM cost-effectiveness.

BC Hydro's DSM electricity savings since F2016 totalled 1,754 GWh/year at March 31, 2017, which equates to 105 per cent of the planned savings of 1,668 GWh/year in the F2017-F2019 RRA. DSM programs delivered 103 per cent of planned savings. Table 3 presents actual cumulative savings as a percentage of plan in F2016 to F2017.

Table 3 Cumulative Electricity Savings since April 1, 2015

Actual as a Percentage of Plan[1]	
	F2017
Codes and Standards	
Residential	108%
Commercial	100%
Industrial	100%
Total Codes and Standards	**106%**
Rate Structures	
Residential Inclining Block Rate	101%
General Service Rate	n/a
Transmission Service Rate	114%
Total Rate Structures	**111%**
DSM Programs	
Residential Sector	
Behaviour	100%
Refrigerator Buy-back	100%
Low Income	121%
New Home	101%
Retail	138%
Home Energy Retrofit Offer	97%
Residential Sector Total	116%
Commercial Sector	
Leaders in Energy Management - Commercial	90%
New Construction	89%
Commercial Sector Total	90%
Industrial Sector	
Leaders in Energy Management - Transmission	119%
Thermo-Mechanical Pulp	100%
Leaders in Energy Management - Distribution	98%
Load Displacement	82%
Industrial Sector Total	107%
Total Programs	**103%**
PORTFOLIO TOTAL	**105%**

Notes:

[1] Reported savings for codes and standards and rates structures are based on planned estimates as well as evaluated results.

The cumulative portfolio DSM electricity savings since F2016 have been achieved at an average net levelized utility cost of -$20 per MWh. Table 4 presents the net levelized utility cost of actual DSM electricity savings achieved from April 1, 2015 through March 31, 2017. Net levelized utility cost is calculated by subtracting capacity benefits from gross utility costs and then dividing the resulting net utility costs by electricity savings. A negative net levelized utility cost means that the subtracted capacity benefits exceed gross utility costs.

Table 4 Utility Cost of Electricity Savings: F2016 to F2017

	Net Levelized Utility Cost ($/MWh)
Codes and Standards	
Residential	-38
Commercial	-20
Industrial	-16
Total Codes and Standards	**-33**
Rate Structures	
Residential Inclining Block Rate	-24
General Service Rate	n/a
Transmission Service Rate	-15
Total Rate Structures	**-20**
DSM Programs	
Residential Sector	
Behaviour	-1
Refrigerator Buy-back	49
Low Income	51
New Home	88
Retail	-23
Home Energy Retrofit Offer	-17
Sector Enabling Activities	n/a
Residential Sector Total	-8
Commercial Sector	
Leaders in Energy Management - Commercial	19
New Construction	25
Sector Enabling Activities	n/a
Commercial Sector Total	22
Industrial Sector	
Leaders in Energy Management - Transmission	11
Thermo-Mechanical Pulp	12
Leaders in Energy Management - Distribution	22
Load Displacement	16
Sector Enabling Activities	n/a
Industrial Sector Total	14
Total Programs	**12**
Rate Structures and Programs	**8**
Portfolio Total	**-20**

Table 5 presents Total Resource Cost Test benefit cost-ratios of actual DSM electricity savings achieved from April 1, 2015 through March 31, 2017. Table 5 shows the Total Resource Cost Test benefit-cost ratios for the Total Resource Cost test and the Total Resource Cost test as modified by the Demand-Side Measures Regulation.

Table 5 Benefit Cost Ratios of Electricity Savings: F2016 to F2017

	Benefit Cost Ratios			
	Utility Test	Total Resource Cost Test	Total Resource Cost Test as modified by DSM Regulation[1]	Ratepayer Impact Measure Test[2]
Codes and Standards				
Residential	n/a	9.8	11.0	1.5
Commercial	n/a	10.6	13.3	1.4
Industrial	n/a	37.8	43.5	2.1
Total Codes and Standards	**210.7**	**9.6**	**11.1**	**1.5**
Rate Structures				
Residential Inclining Block Rate	26.8	26.8	30.8	1.1
General Service Rate	0.0	0.0	0.0	0.0
Transmission Service Rate	77.5	3.7	4.2	1.2
Total Rate Structures	**30.5**	**8.3**	**9.5**	**1.1**
DSM Programs				
Residential Sector				
Behaviour	4.7	5.2	6.0	1.1
Refrigerator Buy-back	1.8	2.4	2.5	0.7
Low Income[3]	1.6	2.4	2.3	0.8
New Home	1.2	1.0	1.1	0.7
Retail	7.3	17.5	19.2	1.3
Home Energy Retrofit Offer	4.6	1.8	2.3	1.1
Sector Enabling Activities	n/a	n/a	n/a	n/a
Residential Sector Total	4.6	4.7	5.3	1.1
Commercial Sector				
Leaders in Energy Management - Commercial	3.1	2.2	2.6	1.0
New Construction	2.7	1.6	2.1	0.9
Sector Enabling Activities	n/a	n/a	n/a	n/a
Commercial Sector Total	2.9	2.0	2.4	0.9
Industrial Sector				
Leaders in Energy Management - Transmission	4.3	2.6	3.0	1.1
Thermo-Mechanical Pulp	4.2	3.5	4.1	1.4
Leaders in Energy Management - Distribution	2.9	2.4	2.7	0.9
Load Displacement	3.6	0.9	1.1	1.3
Sector Enabling Activities	n/a	n/a	n/a	n/a
Industrial Sector Total	3.8	2.1	2.4	1.1
Total Programs	**3.6**	**2.4**	**2.7**	**1.1**
Rate Structures and Programs	**4.1**	**2.6**	**3.0**	**1.1**
Portfolio Total	**12.8**	**5.2**	**6.1**	**1.3**

Notes:

1 In accordance with the DSM Regulation (Ministerial Order M233/2014), the avoided cost of natural gas is valued at BC Hydro's long run marginal cost of acquiring electricity generated from clean or renewable resources in B.C converted to $/GJ in all time periods. Non-energy benefits are valued at 15 per cent of the energy and capacity benefits of electricity and natural gas.

2 While subsection 4(6) of the DSM Regulation precludes the use of the Ratepayer Impact Measure Test in determining cost-effectiveness of a demand-side measure, this benefit cost ratio is included in the table to comply with Directive 42 from the Commission decision on BC Hydro's 2008 LTAP.

3 The Total Resource Cost Test benefit-cost ratio for the Low Income program includes a 40 per cent adder to program benefits, rather than a 15 per cent value for non-energy benefits, in accordance with the DSM Regulation.

4 Mitigation Measures

Based on the experience gathered over the past few years through initiative tracking, the following are mitigation measures that have been undertaken or are planned for the future.

Codes and Standards	
Residential	Cumulative electricity savings in F2017 were approximately on plan.
Commercial	
Industrial	
Rate Structures	
Residential Inclining Block	Cumulative electricity savings in F2017 were on plan.
General Service Rate	No further conservation is forecast from the general service rate
Industrial Transmission	Cumulative electricity savings in F2017 were above plan.
DSM Programs	
Residential Sector	
Behaviour	Cumulative electricity savings in F2017 were on plan. After the success of offering a credit on customer bills as an option for receiving rebates, we are also exploring email money transfers as a means of eliminating cheques altogether as a cost saving measure.
Refrigerator Buy-Back	Cumulative electricity savings in F2017 were on plan. The program has ended per the new DSM Plan in the F2017-F2019 RRA.
Low Income	Cumulative electricity savings in F2017 were above plan. A new strategy we implemented in F2017 was using the call centre credit queue as a proactive channel for promoting the program to customers that are having bill payment issues.
New Home	Cumulative electricity savings in F2017 were on plan. The program has ended per the new DSM Plan in the F2017-F2019 RRA.
Retail	Cumulative electricity savings in F2017 were above plan. A new strategy we implemented in F2017 was a trial promotion of connected home devices through retail channel partners.
Home Energy Retrofit Offer	Cumulative electricity savings in F2017 were approximately on plan. We are working on a project that will improve data access, data analytics, customer processing time and enable creation of an online application form.
Commercial Sector	
Leaders in Energy Management - Commercial	Cumulative electricity savings in F2017 were below plan. The program has made adjustments such as streamlining the Business Energy Savings Incentive component of the program to make it easier for customers to participate and is expected to reach F2018 planned values.
New Construction	Cumulative electricity savings in F2017 were below plan. No mitigation measures are warranted as planned F2018 electricity savings are expected to be achieved based on anticipated project completions.

Industrial Sector	
Leaders in Energy Management - Transmission	Cumulative electricity savings in F2017 were above plan. New strategies that we worked on in F2017 are Energy Monitoring and Targeting systems that show energy savings from Strategic Energy Management (SEM) initiatives at the site; a Compressed Air Optimization pilot to determine if a combination of metering and system audits could result in sustained operational savings from optimizing compressed air systems; as well as launching an offer focused on smaller industrial Key Accounts who have not had access to SEM programs in the past.
Thermo-Mechanical Pulping	Cumulative electricity savings in F2017 were on plan.
Leaders in Energy Management – Distribution	Cumulative electricity savings in F2017 were approximately on plan. New strategies that we worked on in F2017 were the same as Leaders in Energy Management – Transmission and also included Strategic Energy Management Operational Energy Analytics that focused on customers and association members without access to Key Account Managers.
Load Displacement	Cumulative electricity savings in F2017 were below plan. The program has ended per the new DSM Plan in the F2017-F2019 RRA.
Capacity Focused DSM	No capacity savings were planned in F2017 as these are pilot initiatives.

5 Operating Expenditures for Fiscal 2017

BC Hydro's DSM operating expenditures in F2017 totalled $588,642.[3] Table 6 presents DSM operating expenditures in F2017.

Table 6 Operating Expenditures for F2017

	($000)
Labour	482
Consultants/Contractors/Temp Labour	8
Other	98
Total	**589**

6 Allocation of Supporting Initiative Costs to Programs

This section describes how supporting initiative costs are allocated to programs for the purpose of cost test calculations.

In accordance with Directive 61 from the Commission decision on the F05/F06 RRA, when calculating levelized costs and benefit cost ratios for this report, supporting initiative costs are allocated to DSM programs and rate structures based on their share of DSM electricity savings. F2025 has been used as the year for energy savings allocation. As an example, rate structures and programs are forecast to save roughly 530 GWh/year in F2025, so a program that is forecast to save 5.3 GWh/year in F2025

[3] DSM operating expenditures are not included in earlier tables.

represents 1 per cent of the total. In turn, 1 per cent of supporting initiative costs would be allocated to that program in each year when calculating the program's levelized cost or benefit cost ratio.

BC Hydro
Power smart

Fred James
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July 11, 2018

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
F2005/F2006 Revenue Requirements Application
Commission Decision: October 29, 2004; Directive 69 (page 201)
(AMENDED pursuant to 2006 Integrate Electricity Plan and
2006 Long-Term Acquisition Plan
Commission Decision: May 11, 2006; Directive 16 (pages 145 to 146)
2008 Long-Term Acquisition Plan
Commission Decision: July 27, 2009; Directive 36 (page 184))
Fiscal 2017 – Fiscal 2019 Revenue Requirements Application
Commission Decision: March 1, 2018; Directive 23 (page 84)
F2018 Demand-Side Management Activities Annual Report

BC Hydro writes to provide its Report on Demand-Side Management Activities for the 12 months ending March 31, 2018.

For further information, please contact Geoff Higgins at 604-623-4121 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

st/ma

Enclosure (1)

Report on Demand-Side Management Activities for Fiscal 2018

July 11, 2018

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1 Introduction

This BC Hydro annual report to the British Columbia Utilities Commission (**BCUC or Commission**) on Demand-Side Management (**DSM**) activities provides information on DSM expenditures, electricity savings, plan performance and mitigation measures for the 2018 fiscal year, which is the twelve months ending March 31, 2018. This annual report is filed in compliance with the following Commission Directives:

- Directive 69 from the Commission Decision on BC Hydro's Fiscal 2005 – Fiscal 2006 Revenue Requirements Application (**F05-F06 RRA**);
- Directive 16 from the Commission Decision on BC Hydro's 2006 Integrated Electricity Plan and Long Term Acquisition Plan (**2006 IEP/LTAP**);
- Directives 36 and 38 from the Commission decision on BC Hydro's 2008 LTAP; and
- Directive 23 from the Commission decision on BC Hydro's Fiscal 2017 – Fical 2019 Revenue Requirements Application (**F17-F19 RRA**).

Directive 69 of the F05-F06 RRA Decision directed BC Hydro "to provide information to the Commission for on-going review of Power Smart performance through:

- Executive Summaries of milestone evaluation reports and full final evaluation reports for each program;
- Semi-annual reports on DSM activities which, amongst others, will include:
  - ► detailed breakdown of OMA expenses related to support activities carried out within the Power Smart group and in other departments that support the Power Smart organization;
  - ► detailed description of the functions of portfolio level costs and how these costs are allocated to programs;
  - ► summaries of the overall performance of Power Smart with reference to program objectives; and

- variances of fiscal year budgeted and actual deferred capital expenditures and explanation of variances."

Directive 16 of the 2006 IEP/LTAP Decision directed BC Hydro "to continue to file reports on DSM performance as described in Directive 69 of the F05/F06 RRA Decision included in Order No. G-96-04 and to file its Semi Annual Demand-Side Management Reports in the same format as the June 2005 Report with the following enhancements:

Provide annual and cumulative totals since program inception;

(i) Express these values on a per unit basis; and

(ii) Provide the benefit to cost ratios for the three DSM tests."

Directive 36 of the 2006 IEP/LTAP Decision directed BC Hydro to switch from semi-annual to annual DSM performance reports. Directive 38 from the same Decision directed BC Hydro to include in these reports:

> "metrics for each initiative, achievements in relation to milestones, and description of past or planned mitigation measures where warranted. These mitigation measures should include shifting program resources and alternative supply options for each program. Ongoing DSM performance reporting should demonstrate how BC Hydro is continuously pursuing DSM and that specific programs are cost-effective."

BC Hydro files its evaluation reports pursuant to Directive 69 of the F05-F06 RRA Decision separately.

Directive 23 of the F17-F19 RRA Decision directs BC Hydro to "include a line item in BC Hydro's Annual Report on DSM Activities to reflect the NIA activities that are tracked separately."

This annual report addresses the balance of Directives 69 and 16, as well as Directives 36 and 38 of the 2006 IEP/LTAP Decision and Directive 23 of the F17-F19 RRA Decision.

2 Expenditures and Electricity Savings for Fiscal 2018

BC Hydro's DSM expenditures[1] in fiscal 2018 totalled $82.3 million while net incremental DSM electricity savings totalled 543 GWh/year. Expenditures were $37 million or 31 per cent below the Fiscal 2018 DSM Plan presented in BC Hydro's F17-F19 RRA. Overall, net incremental electricity savings as shown in Table 1 were 61 GWh/year or 13 per cent above the DSM Plan.

Table 1 presents planned and actual DSM expenditures and net incremental electricity in fiscal 2018.

[1] Comprising all DSM-related deferred operating expenditures. DSM operating expenditures are presented in Table 7 of this report.

Table 1 Expenditures and Net Incremental Electricity Savings for Fiscal 2018

	Expenditures[1]				Net Incremental Electricity Savings			
	Plan[2]	Actual	Variance		Plan[2]	Actual[3]	Variance	
	$ 000	$ 000	$ 000	%	GWh/yr	GWh/yr	GWh/yr	%
Codes and Standards								
Residential	-	-	-	-	175	254	79	45%
Commercial	-	-	-	-	75	89	14	18%
Industrial	-	-	-	-	7	9	2	30%
Total Codes and Standards	4,833	4,797	(37)	(1%)	257	352	95	37%
Rate Structures								
Residential Inclining Block Rate	300	271	(29)	(10%)	12	16	4	32%
General Service Rate	-	-	-	-	-	-	-	-
Transmission Service Rate	720	283	(437)	(61%)	14	4	(10)	(69%)
Total Rate Structures	1,020	553	(467)	(46%)	26	20	(6)	(22%)
DSM Programs								
Residential Sector								
Behaviour	3,180	1,839	(1,341)	(42%)	14	17	3	18%
Refrigerator Buy-back	-	(0)	(0)	-	-	-	-	-
Low Income	2,607	3,542	935	36%	2	6	3	133%
New Home	-	1	1	-	-	-	-	-
Retail	2,331	2,926	595	26%	4	11	6	151%
Home Energy Retrofit Offer	2,807	2,891	84	3%	5	5	0	6%
Sector Enabling Activities	851	612	(238)	(28%)	n/a	n/a	n/a	n/a
Residential Sector Total	11,775	11,810	35	0%	26	38	13	49%
Commercial Sector								
Leaders in Energy Management - Commercial	20,350	15,221	(5,128)	(25%)	36	33	(3)	(7%)
New Construction	8,507	8,901	394	5%	15	18	3	20%
Sector Enabling Activities	1,020	591	(429)	(42%)	n/a	n/a	n/a	n/a
Commercial Sector Total	29,877	24,714	(5,163)	(17%)	51	51	0	1%
Industrial Sector								
Leaders in Energy Management - Transmission	18,206	14,050	(4,156)	(23%)	50	56	7	14%
Thermo-Mechanical Pulp	14,700	(1,900)	(16,600)	(113%)	50	-	(50)	(100%)
Leaders in Energy Management - Distribution	9,821	7,756	(2,065)	(21%)	23	24	2	8%
Load Displacement	-	-	-	-	-	-	-	-
Sector Enabling Activities	816	582	(234)	(29%)	n/a	n/a	n/a	n/a
Industrial Sector Total	43,543	20,488	(23,055)	(53%)	122	81	(41)	(34%)
Total Programs	**85,195**	**57,012**	**(28,183)**	**(33%)**	**199**	**171**	**(28)**	**(14%)**
Supporting Initiatives								
Public Awareness	6,936	6,999	63	1%	-	-	-	-
Indirect and Portfolio Enabling	7,284	6,075	(1,210)	(17%)	-	-	-	-
Supporting Initiatives Total	**14,220**	**13,074**	**(1,147)**	**(8%)**	-	-	-	-
ENERGY EFFICIENCY PORTFOLIO TOTAL	**105,269**	**75,436**	**(29,833)**	**(28%)**	-	-	-	-
Capacity Focused DSM	14,236	6,868	(7,368)	(52%)	-	-	-	-
PORTFOLIO TOTAL, EE & CF DSM	**119,505**	**82,304**	**(37,201)**	**(31%)**	**483**	**543**	**61**	**13%**

Notes:

1. Including all DSM-related deferred operating expenditures that are relevant for DSM cost-effectiveness.
2. Plan figures are from BC Hydro's F17-F19 RRA, Appendix W with Thermo-Mechanical Pulp Plan adjustments from BCUC IR 2.314.3 and subsequent Compliance filing from April 27, 2018.
3. Reported savings from codes and standards and residential inclining block and general service rate structures are based on planned estimates as well as evaluated results.

The following corresponds to the information provided in Table 1 and are explanations for the above variances:

Codes and Standards	
Residential	Expenditures were approximately on plan. Electricity savings were above plan due to an adjustment of the assumed replacement rate for incandescent lamps under the General Service Lighting (**GSL**) regulation.
Commercial	
Industrial	
Rate Structures	
Residential Inclining Block Rate	Expenditures were approximately on plan. Electricity savings were above plan due to adjustments made to the conservation forecast to reflect an update to the inflation rate and relative residential sales between Tier 1 and Tier 2.
General Service Rate	No further conservation is forecast from the general service rate as BC Hydro has revised its conservation forecast to zero due to the outcomes of the fiscal 2014 LGS/MGS evaluation report.
Transmission Service Rate	Expenditures were below plan due to deferral of the planned Transmission Service Rate evaluation, deferral of planned consultation activities for phase two of the Rate Design Application and lower than expected utilization of engineering resources for energy Customer Base Line (CBL) adjustment and determination reviews. Net incremental electricity savings were below plan in fiscal 2018 because fiscal 2017 electricity savings were higher than planned.
DSM Programs	
Residential Sector	
Behaviour	Expenditures were below plan due primarily to delays in a planned IT enhancement project. Electricity savings were above plan due to higher than forecast participation in select portions of the program, resulting largely from a strong fourth quarter (Q4) promotional campaign.
Low Income	Expenditures and electricity savings were above plan due to higher than planned participation. This was largely due to a strong response to BC Hydro bill inserts as well as leads generated through the BC Hydro call centre that led to a significant increase in the number of Energy Saving Kits being sent to customers than planned.
Retail	Expenditures and electricity savings were above plan due to the success of the lighting campaigns with strong sales of LED lighting particularly multi-packs which provided more savings than planned.
Home Energy Retrofit Offer	Expenditures and electricity savings were approximately on plan.
Sector Enabling Activities	Expenditures were below plan due to planned activities being deferred or cancelled.
Commercial Sector	
Leaders in Energy Management - Commercial	Expenditures and electricity savings were below plan due to customer decisions to delay or cancel projects. Expenditures were also below plan due to projects requiring lower incentive levels than planned.
New Construction	Expenditures were approximately on plan and electricity savings were above plan due to fiscal 2017 delayed projects completing in fiscal 2018.
Sector Enabling Activities	Expenditures were below plan due to planned activities being deferred or cancelled.

Industrial Sector	
Leaders in Energy Management – Transmission	Expenditures were below plan due to a customer cancelling a large incentive project and self-funding the project instead while maintaining planned electricity savings . Electricity savings were above plan due to energy manager's identifying and implementing more energy savings opportunities attributable to strategic energy management practices.
Thermo-Mechanical Pulping	Expenditures and energy savings are below plan due to one project being delayed. Two projects are expected to complete in fiscal 2019 and two more in fiscal 2021.
Leaders in Energy Management – Distribution	Expenditures are below plan due to projects being cancelled or deferred by customers. Electricity savings were approximately on plan due to one large project exceeding its target.
Sector Enabling Activities	Expenditures were below plan due to planned activities being deferred or cancelled.
Total Programs	Expenditures were below plan primarily due to projects not completing as planned in the Thermo-Mechanical Pulping and Commercial Leaders in Energy Management programs. Electricity savings were below plan due to project delays in the Thermo-Mechanical Pulping program.
Supporting Initiatives	
Public Awareness	Expenditures were approximately on plan.
Indirect and Portfolio Enabling	Expenditures were below plan primarily due to lower volume of IT support and enhancements.
Capacity Focused DSM	Expenditures were below plan. Projects related to distributed energy resource management systems and localized capacity were rescheduled to later time periods than previously planned to reflect a slower ramp up.
Portfolio Total	Expenditures were below plan primarily due to projects not completing as planned in the Thermo-Mechanical Pulping program and Capacity Focused DSM. Electricity savings were above plan due to an adjustment of the assumed replacement rate for incandescent lamps under the GSL regulation.

3 Non-Integrated Area Activity

Non-Integrated Area (**NIA**) activity in fiscal 2018 includes pilot project initiatives and DSM program activity. Pilot initiative objectives and activities undertaken to support NIA customers in fiscal 2018 include the following:

- Support education and skills training to build energy literacy in the community
- Facilitate access to opportunity assessments and energy efficient upgrades for homes
- Support the development and implementation of energy efficient housing policy
- Support the development of community energy plans
- Pilot a targeted Low Income Offer for First Nations communities

In addition to the pilot project initiatives, BC Hydro's NIA program activities include the Behaviour, Low Income, Home Energy Retrofit Offer, Leaders in Energy Management Commercial and Leaders in Energy Management Distribution programs. NIA customer participation in general offers such as the Retail program is not tracked separately, and hence is not included here per Directive 23. Table 2 presents expenditures, new incremental electricity savings for BC Hydro's NIA that were tracked separately as well as benefit cost ratios and net levelized cost for fiscal 2018. NIA expenditures and electricity savings included in Table 2 are also included in Table 1 within the applicable initiatives.

Table 2 NIA Activity for Fiscal 2018

	Expenditures[1]	New Incremental Electricity Savings[2]	Benefit Cost Ratios[3]				Net Levelized
	Actual $	Actual kWh/yr	Utility Test	Total Resource Cost Test	Total Resource Cost Test as modified by DSM Regulation[4]	Ratepayer Impact Measure Test	Utility Cost ($/MWh)
DSM Program Activity	$46,918	169,081	6.6	5.0	5.8	1.9	45
Pilot Project Initiatives	$522,554	n/a	n/a	n/a	n/a	n/a	n/a

Notes:

[1] Including all DSM program incentives and pilot project expenditures tracked separately as well as an allocation of Low Income Program incentives.

[2] Including all new incremental electricity savings for DSM programs tracked separately.

[3] Long Run Marginal Cost (**LRMC**) is based on NIA generation costs. Also, all components required to calculate cost effectiveness are not tracked separately therefore assumptions were developed for additional utility costs and customer cost in order to calculate cost effectiveness.

[4] For the low income components included within DSM NIA Program Activity, the Total Resource Cost Test benefit cost ratio includes a 40 per cent adder to program benefits, rather than a 15 per cent value for non-energy benefits, in accordance with the DSM Regulation.

4 Expenditures to Date

BC Hydro's DSM expenditures from fiscal 2016 through fiscal 2018 totalled $324.9 million. Table 3 presents DSM expenditures from April 1, 2015 to March 31, 2018.

Table 3 Expenditures since Fiscal 2016

	F2016 ($ 000)	F2017 ($ 000)	F2018 ($ 000)	Total ($ 000)
Codes and Standards				
Residential	-	-	-	-
Commercial	-	-	-	-
Industrial	-	-	-	-
Total Codes and Standards	**4,688**	**5,057**	**4,797**	**14,542**
Rate Structures				
Residential Inclining Block Rate	506	527	271	1,304
General Service Rate	487	-	-	487
Transmission Service Rate	309	265	283	857
Total Rate Structures	**1,302**	**792**	**553**	**2,647**
DSM Programs				
Residential Sector				
Behaviour	3,236	2,176	1,839	7,251
Refrigerator Buy-back	1,188	0	(0)	1,188
Low Income	2,425	2,890	3,542	8,856
New Home	1,255	(128)	1	1,128
Retail	4,712	4,658	2,926	12,295
Home Energy Retrofit Offer	2,241	2,246	2,891	7,378
Sector Enabling Activities	973	677	612	2,262
Residential Sector Total	16,030	12,519	11,810	40,359
Commercial Sector				
Leaders in Energy Management - Commercial	25,159	25,050	15,221	65,430
New Construction	7,360	8,781	8,901	25,042
Sector Enabling Activities	1,089	682	591	2,363
Commercial Sector Total	33,609	34,513	24,714	92,835
Industrial Sector				
Leaders in Energy Management - Transmission	18,771	14,365	14,050	47,186
Thermo-Mechanical Pulp	19,657	133	(1,900)	17,889
Leaders in Energy Management - Distribution	10,897	8,152	7,756	26,805
Load Displacement	14,481	-	-	14,481
Sector Enabling Activities	968	523	582	2,073
Industrial Sector Total	64,774	23,173	20,488	108,435
Total Programs	**114,412**	**70,204**	**57,012**	**241,629**
Supporting Initiatives				
Public Awareness	8,838	6,799	6,999	22,636
Indirect and Portfolio Enabling	7,278	6,178	6,075	19,530
Supporting Initiatives Total	**16,116**	**12,977**	**13,074**	**42,166**
ENERGY EFFICIENCY PORTFOLIO TOTAL	**136,517**	**89,031**	**75,436**	**300,984**
Capacity Focused DSM	8,644	8,377	6,868	23,890
PORTFOLIO TOTAL, EE & CF DSM	**145,162**	**97,408**	**82,304**	**324,874**

BC Hydro's DSM electricity savings since fiscal 2016 totalled 2,033 GWh/year at March 31, 2018, which equates to 95 per cent of the planned savings of 2,151 GWh/year in the F17-F19 RRA. Table 4 presents actual cumulative savings as a percentage of plan in fiscal 2016 to fiscal 2018.

Table 4 Cumulative Electricity Savings: Fiscal 2016 to Fiscal 2018

Actual as a Percentage of Plan[1]	
Codes and Standards	
Residential	85%
Commercial	87%
Industrial	79%
Total Codes and Standards	**85%**
Rate Structures	
Residential Inclining Block Rate	108%
General Service Rate	n/a
Transmission Service Rate	112%
Total Rate Structures	**111%**
DSM Programs	
Residential Sector	
Behaviour	106%
Refrigerator Buy-back	100%
Low Income	182%
New Home	101%
Retail	151%
Home Energy Retrofit Offer	101%
Residential Sector Total	126%
Commercial Sector	
Leaders in Energy Management - Commercial	90%
New Construction	96%
Commercial Sector Total	91%
Industrial Sector	
Leaders in Energy Management - Transmission	124%
Thermo-Mechanical Pulp	66%
Leaders in Energy Management - Distribution	101%
Load Displacement	85%
Industrial Sector Total	103%
Total Programs	**102%**
PORTFOLIO TOTAL	**95%**

Notes:

[1] Reported savings for codes and standards and rates structures are based on planned estimates as well as evaluated results.

The cumulative portfolio DSM electricity savings from April 1, 2015 through March 31, 2018 have been achieved at an average net levelized utility cost of $5 per MWh. Table 5 presents net levelized utility cost that is calculated by subtracting capacity benefits from gross utility costs and then dividing the resulting net utility costs by electricity savings. A negative net levelized utility cost means that the subtracted capacity benefits exceed gross utility costs.

Table 5 Utility Cost of Electricity Savings: Fiscal 2016 to Fiscal 2018

	Net Levelized Utility Cost ($/MWh)
Codes and Standards	
Residential	n/a
Commercial	n/a
Industrial	n/a
Total Codes and Standards	**n/a**
Rate Structures	
Residential Inclining Block Rate	-25
General Service Rate	n/a
Transmission Service Rate	-15
Total Rate Structures	**-21**
DSM Programs	
Residential Sector	
Behaviour	-5
Refrigerator Buy-back	47
Low Income	28
New Home	75
Retail	-23
Home Energy Retrofit Offer	-19
Sector Enabling Activities	n/a
Residential Sector Total	-10
Commercial Sector	
Leaders in Energy Management - Commercial	17
New Construction	23
Sector Enabling Activities	n/a
Commercial Sector Total	19
Industrial Sector	
Leaders in Energy Management - Transmission	12
Thermo-Mechanical Pulp	5
Leaders in Energy Management - Distribution	18
Load Displacement	13
Sector Enabling Activities	n/a
Industrial Sector Total	12
Total Programs	**10**
Rate Structures and Programs	**5**

Table 6 presents Total Resource Cost Test benefit cost-ratios of actual DSM electricity savings achieved from April 1, 2015 through March 31, 2018. Table 6 shows the Total

Resource Cost Test benefit-cost ratios for the Total Resource Cost test and the Total Resource Cost test as modified by the Demand-Side Measures Regulation.

Table 6 Benefit Cost Ratios of Electricity Savings: Fiscal 2016 to Fiscal 2018

	Benefit Cost Ratios			
	Utility Test	Total Resource Cost Test	Total Resource Cost Test as modified by DSM Regulation[1]	Ratepayer Impact Measure Test[2]
Codes and Standards				
Residential	n/a	8.3	9.3	1.4
Commercial	n/a	9.2	11.9	1.5
Industrial	n/a	45.7	52.5	1.9
Total Codes and Standards	**n/a[3]**	**8.2**	**9.5**	**1.4**
Rate Structures				
Residential Inclining Block Rate	29.1	29.1	33.5	1.0
General Service Rate	0.0	0.0	0.0	0.0
Transmission Service Rate	73.0	2.8	3.2	1.1
Total Rate Structures	**32.8**	**7.2**	**8.2**	**1.1**
DSM Programs				
Residential Sector				
Behaviour	5.4	6.0	6.8	1.1
Refrigerator Buy-back	1.8	2.5	2.6	0.7
Low Income[4]	2.1	3.1	3.1	0.9
New Home	1.3	1.1	1.2	0.7
Retail	7.6	15.4	17.0	1.2
Home Energy Retrofit Offer	4.8	1.9	2.5	1.0
Sector Enabling Activities	n/a	n/a	n/a	n/a
Residential Sector Total	5.0	4.8	5.4	1.1
Commercial Sector				
Leaders in Energy Management - Commercial	3.3	2.6	3.1	1.1
New Construction	2.8	1.7	2.3	1.0
Sector Enabling Activities	n/a	n/a	n/a	n/a
Commercial Sector Total	3.1	2.3	2.7	1.0
Industrial Sector				
Leaders in Energy Management - Transmission	4.0	2.6	3.0	1.0
Thermo-Mechanical Pulp	5.4	4.2	4.8	1.4
Leaders in Energy Management - Distribution	3.2	2.5	2.9	1.0
Load Displacement	4.0	1.0	1.2	1.3
Sector Enabling Activities	n/a	n/a	n/a	n/a
Industrial Sector Total	4.0	2.3	2.6	1.1
Total Programs	**3.9**	**2.6**	**3.1**	**1.1**
Rate Structures and Programs	**4.5**	**2.9**	**3.4**	**1.1**
Portfolio Total	**n/a**	**4.9**	**5.7**	**1.3**

Notes:

[1] In accordance with the DSM Regulation, the avoided cost of natural gas is valued at BC Hydro's LRMC of acquiring electricity generated from clean or renewable resources in B.C converted to $/gigajoule (**GJ**) in all time periods. Non-energy benefits are valued at 15 per cent of the energy and capacity benefits of electricity and natural gas.

[2] While subsection 4(6) of the DSM Regulation precludes the use of the Ratepayer Impact Measure Test in determining cost-effectiveness of a demand-side measure, this benefit-cost ratio is included in the table to comply with Directive 42 from the Commission decision on BC Hydro's 2008 LTAP.

[3] BC Hydro is not solely responsible for codes and standards savings, so this benefit-cost metric is not applicable.

[4] The Total Resource Cost Test benefit-cost ratio for the Low Income Program includes a 40 per cent adder to program benefits, rather than a 15 per cent value for non-energy benefits, in accordance with the DSM Regulation.

5 Mitigation Measures

Based on the experience gathered over the past few years through initiative tracking, the following are mitigation measures that have been undertaken or are planned for the future.

Codes and Standards	
Residential Commercial Industrial	Cumulative electricity savings in fiscal 2018 were below plan. Based on market data, it is expected that as incandescent lamps subject to the General Service Lighting regulation burn out they will continue to be replaced with efficient LED lamps that meet the regulation. Replacement rate assumption has been adjusted in plans moving forward.
Rate Structures	
Residential Inclining Block	Cumulative electricity savings in fiscal 2018 were above plan.
General Service Rate	No further conservation is forecast from the general service rate.
Industrial Transmission	Cumulative electricity savings in fiscal 2018 were above plan.
DSM Programs	
Residential Sector	
Behaviour	Cumulative electricity savings in fiscal 2018 were above plan. In fiscal 2019 the program is conducting a trial to test an application for mobile devices as a means of engaging customers more easily.
Refrigerator Buy-Back	Cumulative electricity savings in fiscal 2018 were on plan. The program has ended per the new DSM Plan in the F17-F19 RRA.
Low Income	Cumulative electricity savings in fiscal 2018 were above plan. In fiscal 2019 the program will focus on coordinating with the newly developed Crisis Fund as a means of reaching customers that have sought bill relief from BC Hydro and helping them to lower their bills in the future.
New Home	Cumulative electricity savings in fiscal 2018 were on plan. The program has ended per the new DSM Plan in the F17-F19 RRA.
Retail	Cumulative electricity savings in fiscal 2018 were above plan. In fiscal 2019 the program will begin offering email money transfers for those customers that do not opt for credit on bill, further reducing costs by eliminating cheques.
Home Energy Retrofit Offer	Cumulative electricity savings in fiscal 2018 were on plan. In fiscal 2018 the program launched an online application form, greatly improving the customer experience and reducing application processing and rebate payment times by more than half.
Commercial Sector	
Leaders in Energy Management - Commercial	Cumulative electricity savings in fiscal 2018 were below plan. The program is making adjustments such as incenting HVAC control measures, launching an offer focused on social housing for multi-unit residential buildings to implement energy conservation measures and having Business Energy Advisors work with small medium businesses in order to help reach fiscal 2019 planned values.
New Construction	Cumulative electricity savings in fiscal 2018 were approximately on plan. No mitigation measures are warranted as planned fiscal 2019 electricity savings are expected to be achieved based on anticipated project completions.

Industrial Sector	
Leaders in Energy Management - Transmission	Cumulative electricity savings in fiscal 2018 were above plan. Continued development in fiscal 2018 of savings directly associated with strategic energy management has resulted in increased savings in this area.
Thermo-Mechanical Pulping	Cumulative electricity savings in fiscal 2018 were below plan. No mitigation measures are warranted as delays in large projects are possible. Two projects are currently being implemented and expected to complete in fiscal 2019. The remaining two projects are still subject to delay but currently planned in fiscal 2021. BC Hydro is in contact with the customer to ensure the best information is available for planning purposes.
Leaders in Energy Management – Distribution	Cumulative electricity savings in fiscal 2018 were on plan. A new strategy that we worked on in fiscal 2018 is the introduction of the cohort energy manager targeting medium-sized firms that completed its first full year with three cohorts in progress. This initiative will begin to deliver electricity savings in fiscal 2019.
Load Displacement	Cumulative electricity savings in fiscal 2018 were below plan. The program has ended per the new DSM Plan in the F17-F19 RRA.
Capacity Focused DSM	No capacity savings were planned in fiscal 2018 as these are pilot initiatives.

6 Operating Expenditures for Fiscal 2018

BC Hydro's DSM operating expenditures in fiscal 2018 totalled $521,043.[2] Table 7 presents DSM operating expenditures in fiscal 2018.

Table 7 Operating Expenditures for Fiscal 2018

	($000)
Labour	458
Consultants/Contractors/Temp Labour	11
Other	53
Total	**521**

7 Allocation of Supporting Initiative Costs to Programs

This section describes how supporting initiative costs are allocated to programs for the purpose of cost test calculations.

In accordance with Directive 61 from the Commission decision on the F05-F06 RRA, when calculating levelized costs and benefit cost ratios for this report, supporting initiative costs are allocated to DSM programs and rate structures based on their share of DSM electricity savings. Fiscal 2025 has been used as the year for energy savings allocation. As an example, rate structures and programs are forecast to save roughly 700 GWh/year in fiscal 2025, so a program that is forecast to save 7 GWh/year in

[2] DSM operating expenditures are not included in earlier tables.

fiscal 2025 represents one per cent of the total. In turn, one per cent of supporting initiative costs would be allocated to that program in each year when calculating the program's levelized cost or benefit cost ratio.

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Appendix AA

Demand-Side Management Measurement, Verification and Evaluation

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1 Introduction

Measurement and verification, and evaluation are the final steps in BC Hydro's process to refine our estimates of the impacts from demand-side management (**DSM**) initiatives. Impacts include electricity savings from energy conservation initiatives, peak demand reductions from capacity-focused initiatives and fossil fuel and greenhouse gas reductions and electricity consumption increases from low carbon electrification initiatives. Evaluation also identifies opportunities to improve DSM program effectiveness or efficiency.

This appendix provides an overview of BC Hydro's DSM measurement and verification, and evaluation activities, including their purpose and objectives, the principles that guide them, the types of activities undertaken and planned work in the two-year period of fiscal 2020 to fiscal 2021. It also provides an overview of the functions' organizational structure, how the work is delivered, and our oversight process.

2 Measurement and Verification

The objective of BC Hydro's measurement and verification activities is to verify energy impacts at the project level, and by doing so, support decisions on program management and rate structure implementation, program impact evaluations and customer satisfaction.

BC Hydro's measurement and verification activities are guided by six principles: Neutrality, Professional Standards, Qualified Practitioners, Specified Selection Criteria, Business Integration and Coordination.

Measurement and verification activities fall into three major categories: data collection, data analysis and the review of a selection of customer submissions under the Transmission Service Rate.

Data collection involves a variety of sources, including BC Hydro permanent or temporary metering, customer data systems and weather data providers.

The collected data is analyzed to estimate the energy impacts of a demand-side management project. Depending on the energy measures implemented, a variety of data analysis techniques can be used, including:

- Calculating the difference between pre- and post-retrofit energy consumption and then adjusting for differences in relevant variables such as production levels;
- Regression analysis of measured energy consumption against measured drivers of electricity consumption;
- Measuring hours of lighting use and then multiplying by changes in lighting fixture wattages; or
- Calibrated computer simulation modelling of a facility or end-use equipment.

BC Hydro's measurement and verification function also supports implementation of the Transmission Service Rate for large industrial customers. Measurement and verification staff review a selection of customer submissions under the Rate to determine if the customer's electricity savings estimate claimed seems reasonable and if the customer should be required to conduct measurement and verification activities to support their electricity savings estimate.

3 Evaluation

The purpose of the evaluation function is to refine estimates of DSM impacts and identify program improvements in a rigorous and neutral manner in support of DSM and Integrated Resource Plan (**IRP**) decisions, risk management, and stakeholder confidence.

The objectives of the evaluation function are as follows:

- Support DSM investment and IRP decisions by evaluating impacts of DSM initiatives;
- Support DSM program management decisions by identifying opportunities to improve programs; and
- Fulfill Commission directives and guidelines regarding the evaluation of DSM programs and initiatives.

Evaluation activities are guided by six principles: Neutrality, Professional Standards, Qualified Practitioners, Appropriate Coverage, Business Integration, and Coordination.

BC Hydro conducts both impact and process evaluations, and these two types of evaluations are defined below.

The purpose of an impact evaluation is to estimate the impacts attributable to a DSM initiative or from a change in the efficiency of certain products within a specific timeframe that includes a change in an energy efficiency code or standard.

Evaluated gross impacts quantify impacts realized among participating customers, without determining what share of those impacts is directly attributable to a DSM initiative. Common methods for evaluating gross impacts include analyzing data for a sample of projects and extrapolating the results to the population of projects, conducting billing analysis on the population of projects, or analyzing market changes for energy efficient products based on sales data or population surveys.

Evaluated net impacts quantify impacts that are attributable to a specific DSM initiative, such as a program or rate structure. Net impacts can be estimated directly through purposely designed evaluation methods using comparison groups or econometric modelling, or using survey techniques and analysis to inform free ridership and spillover adjustments that can be applied to estimates of evaluated gross impacts.

The purpose of a process evaluation is to identify program improvements that will increase program effectiveness or efficiency. Common methods for process evaluations include analysis of program tracking data and information collected through surveys and structured interviews.

Most impact evaluations also identify opportunities for program improvements in addition to identifying gross or net impacts of a DSM initiative.

The evaluation work plan is shown in the table below. It includes the list of planned evaluations and various data collection activities that provide inputs to evaluations.

	F2020	**F2021**
Impact Evaluations		
Residential Programs		
Retail (Lighting and Appliances)		X
Home Renovation Rebate Offer	X	
Behaviour	X	
Commercial Programs		
Leaders in Energy Management-Commercial: Continuous Optimization Offer	X	
New Construction	X	
Industrial Programs		
Leaders in Energy Management - Transmission	X	
Leaders in Energy Management - Distribution		X
Codes and Standards		
General Service Lamps		X
TBD		TBD
Capacity Focused and Localized DSM		
TBD		
Process Evaluations		
Alliance Referral and e-Catalog Management Processes	X	

	F2020	F2021
Main Data Collection Activities		
Retail Program Survey	X	X
Commercial/Industrial Program Survey	X	X
Retail Shelf Space Study	X	X
TV Sales Data	X	
Residential In Home Audits		X
Residential End Use Survey		X

4 Organizational Structure and Work Delivery

Measurement and verification, and evaluation are an integral part of demand-side management program and conservation rate implementation. The Measurement and Verification, and Evaluation departments are located within Conservation and Energy Management, BC Hydro's DSM business unit. This supports quality and value to BC Hydro by facilitating information exchange between internal clients and staff in Measurement and Verification, and Evaluation. Measurement and verification, and evaluation staff understand BC Hydro's DSM programs, initiatives and data and, as a result, deliver better quality evaluations to support our internal client needs. Similarly, internal clients are better able to understand objectives and results of measurement and verification, and evaluation activities due to their proximity to these functions.

Independence

The independence of the measurement and verification, and evaluation functions from other functions in Conservation and Energy Management is important and established through the organizational structure. The Measurement and Verification, and Evaluation departments are separate from, and have different managers than, the departments responsible for the development and management of DSM programs and initiatives. Independence of the measurement and verification, and evaluation functions is further maintained through the oversight processes described below.

Work Delivery

BC Hydro utilizes a mix of staff and contractors to deliver measurement and verification, and evaluation work.

In measurement and verification, BC Hydro staff do all annual work planning and data collection and the majority of planning, analysis, and report writing for individual measurement and verification projects. In some situations, customers may collect data from their facility control systems and provide it to BC Hydro for measurement and verification purposes. Contractors do a minority of the planning, analysis and report writing work, particularly when the analysis requires specialized skill such as energy simulation modelling or when the volume of work exceeds staff capacity.

In evaluation, BC Hydro staff do all annual work planning and the majority of planning, analysis, and report writing for individual evaluation projects. Contractors do the majority of data collection and a minority of analysis for individual evaluation projects. Contractors are relied upon for analysis particularly when simple analytical work would be a poor use of staff time given their expertise, or when the volume of analytical work exceeds staff capacity.

Over the three years of fiscal 2016 through fiscal 2018, staff labour, contractors and other categories respectively accounted for 68 per cent, 26 per cent and 5 per cent of our total costs for measurement and verification, and evaluation.

There are several reasons behind this division of labour between staff and contractors:

1. BC Hydro is a Crown corporation without an incentive mechanism that would make it profit from DSM impacts, and thus is not in a conflict of interest with

respect to the evaluation or measurement and verification of DSM impacts. Without a DSM incentive mechanism, BC Hydro does not profit from the over-estimation of DSM impacts. This is in contrast to a number of other jurisdictions in North America, including California, where electricity is delivered by investor-owned utilities with incentive mechanisms for DSM. In these jurisdictions, utilities are in a conflict of interest with respect to the evaluation or measurement and verification of DSM impacts, since evaluation results influence incentive payments to utilities for DSM. In many of these jurisdictions, the majority of measurement and verification, and evaluation work is outsourced to contractors;

2. Costs are lower due to our use of BC Hydro staff instead of contractors. Average hourly costs for measurement and verification, and evaluation contractors are close to twice that of equivalent BC Hydro staff;

3. Quality is higher due to our use of BC Hydro staff instead of contractors. As noted above, BC Hydro measurement and verification, and evaluation staff understand BC Hydro DSM initiatives and data and, as a result, deliver better quality evaluations to support our internal client needs; and

4. Privacy requirements prevent BC Hydro from using contractors for some evaluation work. In its handling of personal information, including electricity consumption and other data pertaining to residential customers, BC Hydro must comply with the *BC Freedom of Information and Protection of Privacy Act*. The Act requires BC Hydro to safeguard personal information and contains prohibitions on the storage and access of personal information outside Canada. BC is one of only two Canadian provinces with such prohibitions (the other being Nova Scotia). These prohibitions effectively mean that BC Hydro cannot outsource evaluation analytical work on residential DSM initiatives to contractors based in the United States without Canadian subsidiaries and data

servers. This is significant since the vast majority of DSM evaluation consulting firms in North America are based in the United States.

We believe the division of labour between staff and contractors strikes the right balance for BC Hydro’s needs. Relative to an alternative scenario with more work conducted by contractors, the current division of labour results in lower costs and higher quality, and, as noted above, independence of the measurement and verification, and evaluation functions is established through the organizational structure and maintained through the oversight process described below.

Oversight

In the interest of quality and independence, both measurement and verification, and evaluation have oversight processes to ensure that their products are neutral and align with industry practice.

For measurement and verification, the oversight process includes the following steps:

1. Measurement and verification results for complex projects are reviewed by an internal measurement and verification peer; and
2. A sample of measurement and verification reports are reviewed by an external measurement and verification advisor to ensure that they utilize appropriate methodologies and align with industry practice.

For evaluation, the oversight process includes the following steps:

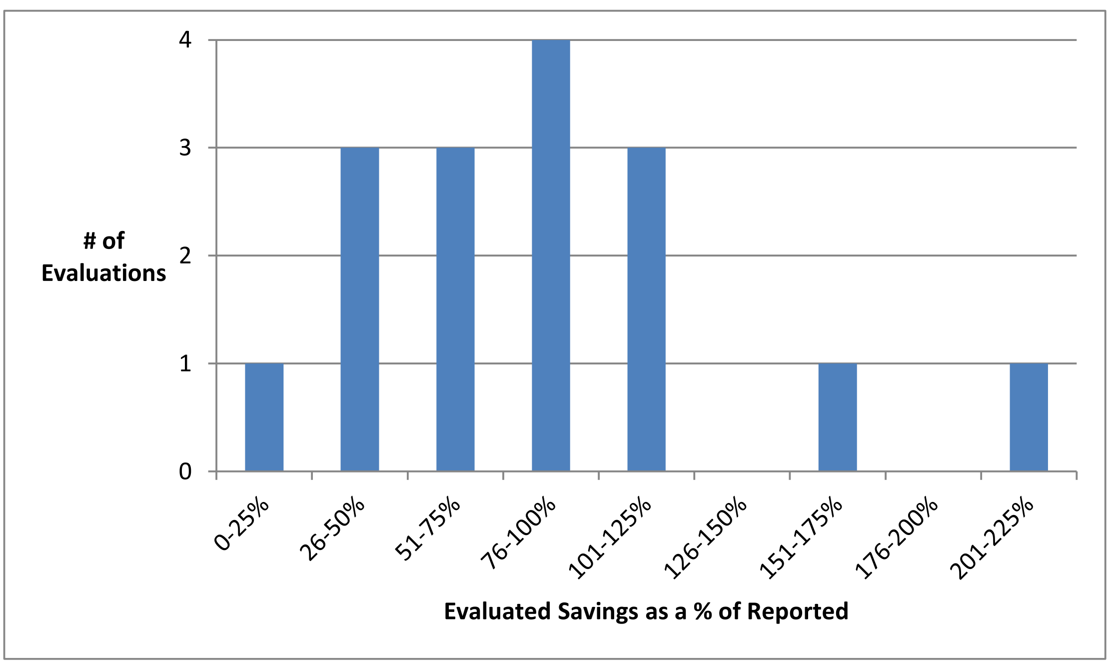
1. Evaluation plans and methodologies are reviewed by Evaluation management and evaluation peers. Evaluation plans involving new methodologies may also be reviewed by external evaluation advisors;
2. Draft evaluation reports are reviewed by two external evaluation advisors who ensure that BC Hydro evaluations utilize appropriate methodologies and align

with industry practice. Draft reports are also reviewed by Evaluation management, and evaluation results are reviewed by internal peers; and

3. Final evaluation reports are reviewed and subject to approval by an Evaluation Oversight Committee made up of BC Hydro staff representing business units with an interest in DSM and chaired by a staff person from outside the Conservation and Energy Management business unit. The external evaluation advisors participate in Evaluation Oversight Committee meetings and act as a resource to Committee members. The Evaluation Oversight Committee ensures that BC Hydro's DSM evaluations are objective, unbiased, and of sufficient quality.

Evaluation Results

The following histogram summarizes the results of 16 DSM impact evaluations conducted by BC Hydro over a five-year period from fiscal 2014 through fiscal 2018. Eleven of the 16 evaluations found electricity savings to be less than reported while five evaluations found electricity savings to be more than reported.



5 Annual Evaluation Reports to the Commission

In compliance with Directive 66 (page 197) of the Commission Decision dated October 29, 2004 on BC Hydro's Fiscal 2005 to Fiscal 2006 Revenue Requirements Application, BC Hydro submits an annual DSM Milestone Evaluation Summary Report to the Commission. Appendix AA includes the past two annual reports, covering fiscal 2017 and fiscal 2018.

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Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix AA

Attachment 1

Demand Side Management Milestone Evaluation Summary Report Fiscal 2017

BC Hydro
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Fred James
Chief Regulatory Officer
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bchydroregulatorygroup@bchydro.com

January 15, 2018

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
2004/05 and 2005/06 Revenue Requirements Application
Commission Decision: Order No. G-96-04, October 29, 2004, Directive 66 (page 197)

BC Hydro writes to submit its F2017 Demand Side Management Milestone Evaluation Summary Report (**the Report**), dated December 2017 in compliance with Directive 66 (page 197) of the Commission Decision dated October 29, 2004. Directive 66 directs BC Hydro to file the executive summaries of its milestone evaluation reports and full final evaluation reports for all its Power Smart programs. The Report summarizes the impact evaluations completed during F2017 for the following:

1. Residential Lighting: F2013-F2015 Q1;
2. Continuous Optimization: F2011-F2013;
3. High Performance Buildings and Commercial New Construction: F2008-F2011; and
4. Power Smart Partner - Transmission: F2012-F2014.

For further information, please contact Geoff Higgins at 604-623-4121 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

st/ma

Enclosure

BC Hydro
Power smart

Demand Side Management Milestone Evaluation

Summary Report F2017

December 2017

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December 2017

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1.0 Introduction

This report summarizes the milestone evaluations of demand-side management (**DSM**) initiatives completed by BC Hydro in fiscal year 2017 (**F2017**). It is filed in compliance with Directive 66 of the British Columbia Utilities Commission (**BCUC**) decision on BC Hydro's F05/F06 Revenue Requirements Application (dated October 29, 2004), which "*directs BC Hydro to file the executive summaries of its milestone evaluation reports and full final evaluation reports of all its Power Smart programs*" (page 197).

BC Hydro evaluates its DSM initiatives to improve its estimates of realized DSM electricity savings and to improve their effectiveness and efficiency.

DSM evaluation activities are guided by the following six principles:

- Objectivity and Neutrality: Evaluations are to be objective and neutral.
- Professional Standards: Evaluation work is guided by industry standards and protocols.
- Qualified Practitioners: BC Hydro employs qualified staff and consultants to conduct evaluations.
- Appropriate Coverage: BC Hydro strives to achieve defined coverage levels for its evaluation of DSM initiatives.
- Business Integration: The evaluation function is integrated into BC Hydro's DSM business process of planning, implementation, reporting and evaluation.
- Coordination: BC Hydro evaluation work is coordinated with FortisBC and other DSM partners where feasible.

BC Hydro DSM evaluations are subject to an independent oversight process to ensure that they are neutral and unbiased, of sufficient quality for their intended purposes, and consistent with industry standards and protocols.

1.1 Completed Evaluations

Impact evaluations summarized in this report include the following:

- Residential Lighting: F2013-F2015 Q1;
- Continuous Optimization: F2011-F2013;
- High Performance Buildings and Commercial New Construction: F2008-F2011; and
- Power Smart Partner - Transmission: F2012-F2014.

2.0 Residential Lighting: F2013-F2015 (Q1)

2.1 Introduction

The impacts and effects of BC Hydro's Residential Lighting program were evaluated for the period April 2012 through June 2014 (F2013 through the first quarter of F2015). Prior to June 2014 the program was dedicated only to residential lighting. After June, residential lighting became one component of a larger Retail Program that included a range of residential consumer products, including lighting. Prior evaluations of the Residential Lighting Program covered the period up to F2012.

The objectives of the Residential Lighting program included: (1) sustain and increase a greater market share of energy-efficient lighting in advance of regulations for more efficient lighting; (2) promote efficient lighting products not covered by regulations and newer products such as Light Emitting Diodes (**LEDs**); (3) promote and increase awareness of efficient lighting products province-wide and drive customers to retailers to purchase efficient products; and (4) provide residents province-wide with an accessible and simple lighting program.

The Residential Lighting program was first launched in 2002 and operated continuously from then until June 2014. The Residential Lighting program was initially launched as a Compact Florescent Lamps (**CFL**) pilot initiative in three communities. Bulk CFL purchases were made by BC Hydro and distributed free to customers using redeemable coupons at retail partners. The CFL pilot was later expanded to additional regions, and to include incentive coupons to encourage customers to purchase CFL torchieres rather than halogen torchieres. In October 2004 the program launched a province-wide fall campaign that focused on CFLs, seasonal LEDs and CFL torchieres. The program continued to update its product mix over the years that followed to reflect market changes. In June 2007, the program transitioned from spiral CFLs to specialty CFLs. Specialty CFLs continued to be promoted until 2013. From July 2011 to the end of the evaluation period, the program focused primarily on promoting LED lamps. CFL and LED fixtures that complied with the ENERGY STAR labelling program were also promoted. Instant in-store discounts and manufacturer buy-downs continued to be offered during time limited campaigns that ran in spring and fall. New major retail partners were added to increase market penetration of energy-efficient lighting technologies.

The program has provided retailer education for the residential lighting market since its inception. Retailer partnerships continued to be a key component of the Residential Lighting program over the period evaluated.

BC Hydro's service territory covers approximately 1.7 million residential accounts. Over the period evaluated, the program provided rebates for almost 800,000 lighting units, of which over 500,000 were LED lamps.

2.2 *Approach*

Four evaluation objectives were identified, each with specific researchable questions, as summarized in the following table:

Table 2.1. Evaluation Objectives and Research Questions

Objectives	Research Questions
1. Program effectiveness	• How did BC Hydro customer awareness, purchases, and promotion recall levels for energy-efficient lighting products compare to similar customers with a less extensive residential lighting program? • How satisfied were BC Hydro residential customers with CFL and LED lamps? • What were program participants' perceptions of program influence on their purchase decisions and their intended actions in the absence of the program? • How effective was the program in influencing retail partners' purchase and stocking decisions? • How influential was the program in encouraging retail partners to sell more energy-efficient products? • How satisfied were retail partners with the program?
2. Market trends	• What were trends in pricing and shelf space shares for lamps and fixtures? • What were trends in lamps in BC Hydro residential customer homes?
3. Evaluated gross unit electricity savings	• What were the hours of use for lamps and fixtures? • What was the peak coincidence of lamps and fixtures? • What was the power draw of the energy-efficient and baseline lighting products? • What was the installation rate for the various lighting types? • What were the unit energy savings per lighting product incented by the program?
4. Evaluated net electricity savings	• What was the free rider rate? • What was the spillover and market effects rate? • What were net energy and peak savings by lighting product type? • What were the annual, incremental evaluated savings for the program overall and how did they compare to reported savings? • What were the sources of any variances between evaluated and reported savings?

Table 2.2 summarizes, for each of the evaluation objectives, the evaluation data and methods used.

Table 2.2. Evaluation Objectives, Data and Methods

Objectives	Data sources	Method
1. Program effectiveness	• 2012 BC Hydro Residential Customer Survey (n = 601) • 2012 Comparison group survey (n = 450) • 2012, 2013, 2014 Retail Partners Surveys (n = 9, 8, 5) • • 2014 Lighting Program participant survey (n = 80)	• Cross tabulations • Trend analysis • Z-tests
2. Market trends and effects	• Annual Household Lighting Shelf Space Study from 2001 to 2014 (~ 40 stores per year) • BC Hydro residential end use surveys from 1998 to 2014 (n = 4,248 to 7,604 depending on year)	• Cross tabulations • Trend analysis
3. Evaluated gross unit electricity savings	• Program tracking data • 2010 Residential monitoring study (n = 292 lighting points) • Sales data from participating retailers • 2014 Lighting Program participant survey (n = 80) • BC Hydro Standard Procedure: Cross Effects	• Engineering algorithms • Load Shape analysis
4. Evaluated net electricity savings	• Results of objective 3 • Sales data from participating retailers • 2012 BC Hydro Residential Customer Survey (n = 602) • 2012 Comparison group surveys (n = 450) • 2014 Lighting Program participant survey (n = 80) • BC Hydro Standard Procedure: Cross Effects	• Market data analysis • Cross tabulation

2.3 Results

Results for Objective 1: Program Effectiveness

Program effectiveness was assessed using a set of residential customer surveys delivered in 2012. BC Hydro and comparison group customers had similar awareness levels for all lighting products with the exception of LED lamps. Awareness levels for LED lamps were greater for BC Hydro residential customers than for comparison group customers (73 per cent vs 66 per cent awareness, respectively) and this difference was highly statistically significant.

BC Hydro residential customers and comparison group customers were asked if they had purchased various lighting products over the past year. A greater share of BC Hydro customers had purchased halogen and LED lamps than did comparison group customers, and these differences were highly statistically significant. A lesser share of BC Hydro customers purchased incandescent lamps than did comparison group customers, and this difference was also statistically significant. BC Hydro residential customers and comparison group customers who indicated that they had purchased a particular lighting product over the past year were then asked how many they purchased. BC Hydro customers who purchased LED lamps purchased a greater number of them than did comparison group customers who purchased LED lamps (averages of eight versus five lamps, respectively). BC Hydro customers who purchased incandescent lamps purchased fewer than did comparison group customers who purchased such lamps (averages of eight versus 11 lamps, respectively).

The program's effectiveness in promoting energy-efficient product sales was examined by comparing recall of information, advertising or promotions between the treatment group and the comparison group. Recall of related promotions was higher for both CFL and LED lamps among BC Hydro customers than among comparison group customers and the differences were highly statistically significant.

BC Hydro customers reported high levels of satisfaction with LED lamps, with 92 per cent of respondents reporting being somewhat or very satisfied with them. Satisfaction levels were more mixed for specialty CFLs – with 72 per cent of respondents reporting being somewhat or very satisfied with them and 19 per cent reporting being somewhat or very dissatisfied.

Households identified as having purchased BC Hydro discounted bulbs and fixtures during the lighting campaigns were queried as to their likelihood of purchasing the units had the discount not been available. For households that purchased LEDs during the fall 2012 campaign, 55 per cent believed that they either 'definitely would have' or 'probably would have' purchased the bulbs anyway had the discount not been available. For households that purchased LEDs during the spring 2014 campaign, 61 per cent believed they 'would have purchased at least some of the bulbs anyway' had the discount not been available.

Retail partners were asked about their satisfaction with the program in each of the three years of the evaluation period. Satisfaction levels were high in each of F2013 and F2014, but declined to moderate levels in F2015.

Retail partners were also asked about the influence of the program on sales of energy-efficient lighting products. Retail partners rated the program as being more influential on sales of energy-efficient lighting products in F2013 and F2014 than they did in F2015. Retail partners viewed the program as being more influential on sales of energy-efficient lamps than on sales of energy-efficient lighting fixtures.

Results for Objective 2: Market Trends

Over the evaluation period, incandescent lamps had the largest shelf space share among residential lighting product retailers, ranging from 34 per cent to 38 per cent. CFL lamp shelf space share declined from 25 per cent to 20 per cent, while LED lamps shelf space share increased from 10 per cent in 2012 to

17 per cent in 2014. Shelf space devoted to ENERGY STAR fixtures appeared to be modest at between 4 and 7 per cent.

LED lamp prices declined from an average of $22.22 in 2012 to $16.12 by 2014. Prices for other lamp types were stable or exhibited no ongoing trend, while prices for fixtures increased.

Between 2002 (when the residential lighting program began) and 2014 the total number of lamps installed in BC Hydro residential customer homes increased from an average of 33 to 38. Over the same period, the average number of incandescent lamps per household in BC Hydro's service territory dropped from 24 to 16, while the average number of efficient lamps (CFL or LED) increased from one to 13.

Between 2012 and June 2014 (within the period covered by this evaluation), the total number of lamps installed in BC Hydro residential customer homes remained stable at 38. The average number incandescent lamps dropped from 17 to 16 per home, while the average number of LED lamps increased from one to three lamps per home. The number of CFL lamps was steady at an average of ten per home.

Results for Objectives 3: Evaluated Gross Unit Electricity Savings

Evaluated gross unit electrical savings are presented below for each of the four lighting product types rebated through the program over the evaluation period.

Table 2.3. Evaluated Gross Unit Savings

	Efficient Power Draw (Watts)	Baseline Power Draw (Watts)	Power Savings (Watts)	Annual hours	Peak Coincidence	(1 – cross effects)	Installation rate	Evaluated Gross Unit Energy Savings (kWh/yr)	Evaluated Gross Unit Peak Demand Savings (W)
	A	B	C = B - A	D	E	F	G	H = (C*D*F*G)/ 1,000	I = C*E*F*G
Specialty CFL lamps	16	54	39	934	0.31	0.95	0.76	26	9
LED lamps	10	54	45	934	0.31	0.94	0.79	31	10
LED fixtures	11	54	43	934	0.31	0.94	0.94	35	12
CFL fixtures	25	103	78	934	0.31	0.97	0.94	67	22

Free Ridership and Market Effects

Free ridership by lighting product type is presented below.

Table 2.4. Evaluated Free Ridership

	F2013 (%)	F2014 (%)	F2015 (%)
Specialty CFL lamps	58	58	N/A
LED lamps	9	9	39
LED fixtures	23	30	60
CFL fixtures	80	80	90

By analyzing differences between BC Hydro and comparison group customers, an overall estimate of the net effects of the program was developed for LED lamps and specialty CFL lamps, inclusive of market effects across the entire BC Hydro service territory. Due to limitations in the Dakotas as a representative comparison group for BC Hydro customers, the level of uncertainty associated with this estimate of the program's net effects is higher than the uncertainty associated with the free ridership estimate alone. An estimate of market effects could not be produced for ENERGY STAR fixtures.

The net-to-gross ratio inclusive of market effects was 477 per cent for LED lamps for F2013 and F2014. This result indicates that the program played an important role in accelerating awareness, purchase and installation of LED lamps across BC Hydro's service territory. Evidence presented in this evaluation indicates that the LED market is changing rapidly. As such, the market effects observed in the evaluation period may not be applicable to future periods.

The net-to-gross ratio inclusive of market effects was zero for specialty CFL lamps. The program provided rebates for specialty CFL lamps in the first part of the evaluation period only, and discontinued the offer in F2014. One explanation of an overall net-to-gross ratio of zero may be that program promotional efforts influenced customers to purchase LED lamps, instead of CFL lamps, outside the campaign period.

Results for Objectives 4: Evaluated Net Electricity Savings

The evaluated and reported net savings by year is shown below. Evaluated savings are incremental annual saving, adjusted for the fact that not all lighting products are immediately installed.

Table 2.5. Reported and Evaluated Net Energy and Peak Savings

	Energy Savings (GWh/year)			Peak Demand Savings (MW)		
	Reported	Evaluated Net Direct	Evaluated Net with Market Effects	Reported	Evaluated Net Direct	Evaluated Net with Market Effects
F2013	14.6	8.2	30.2	5.2	2.7	10.0
F2014	6.6	5.5	25.0	2.4	1.8	8.3
F2015 First Quarter	4.9	3.1	3.1	1.8	1.0	1.0
Total	**26.1**	**16.7**	**58.4**	**9.3**	**5.6**	**19.4**

Evaluated net direct savings are estimated based on the number of rebated products, the evaluated gross unit savings per lighting product, and the evaluated free ridership estimate. The level of uncertainty associated with the evaluated net direct savings is low. Evaluated net direct savings are lower than reported savings because evaluated free ridership was higher than was assumed in reported savings, and because evaluated savings include an installation rate adjustment to account for the fact that some rebated lighting products were placed in storage, whereas reported savings do not include an installation rate adjustment.

Evaluated net savings with market effects are estimated in the same manner as evaluated net direct savings for ENERGY STAR fixtures. For LED lamps and specialty CFL lamps, evaluated net savings with market effects reflect the program's impact across the entire BC Hydro service territory, and they likely include the effects of program efforts promoting LED lamps in the year prior to the evaluation period. The level of uncertainty associated with evaluated net savings with market effects is high. Evaluated net savings with market effects are higher than reported savings and evaluated net direct effects because of market effects for LED lamps.

2.4 Findings and Recommendations

Findings

1. BC Hydro's residential lighting program provided rebates for almost 800,000 lighting units over the period evaluated, of which over 500,000 were for LED lamps.
2. Over the evaluation period, the average number of LED lamps installed in BC Hydro residential customer homes more than doubled from an average of one to three lamps per home. The retailer shelf space share dedicated to LED lamps increased from 10 per cent to 17 per cent while average LED prices declined from $22.22 to $16.12.
3. BC Hydro customers had higher levels of LED lamp awareness, share of customers purchasing LED lamps, and number of LED lamps purchased relative to comparable residential customers with a less extensive residential lighting program.
4. BC Hydro customers reported high satisfaction with LED lamps, and mixed satisfaction with specialty CFL lamps.
5. The majority of BC Hydro residential customers reported that the lighting program was influential in their purchase of energy-efficient lamps.
6. Retail partner satisfaction with the program was high in F2013 and F2014, but modest in F2015. Retail partners indicated that the program was more influential on sales of energy-efficient lighting products in the earlier part of the evaluation period than the later part.
7. The reliability of gross evaluated savings would be improved with additional data on the wattage of rebated lamps and an updated metering study of lighting hours-of-use and load shape among BC Hydro residential customers. The reliability of the net-to-gross ratio would be improved with additional data on the sales of lighting products throughout the entire year.
8. The net-to-gross ratio for LED lamps including market effects was 477 per cent for F2013 and F2014. The net-to-gross ratio for specialty CFL lamps including market effects was zero. These results indicate that the program accelerated adoption of LED lamps, and that the market for CFL lamps has now matured. The net-to-gross ratio for LED lamps including market effects is not applicable past F2014.
9. High levels of free ridership were measured for LED and CFL fixtures by analyzing differences in sales. However, evidence suggests that high free ridership may be more reflective of low levels of sales of energy efficient fixtures overall, as opposed to high levels of natural conservation. Only 33 per cent of BC Hydro customers were aware of ENERGY STAR fixtures and only 2 per cent reported purchasing one.
10. Evaluated net savings including market effects over the evaluation period were 58.4 GWh/year, while reported savings were 26.1 GWh/year respectively. The main source of variance was the large evaluated estimate of market effects for LED lamps in F2013 and F2015. Lesser sources of variance were the installation rate and unit power savings.

Recommendations

Recommendations one through four are for program management, while recommendation five is for Evaluation.

1. To improve the quality and reduce the cost of future evaluations, request data on the numbers and descriptions of all lighting products sold in each month of the year, from all retail partners.
2. Given that some lamps purchased with program assistance are temporarily placed in storage, consider applying an installation rate adjustment to reported savings in periods that have yet to be evaluated.
3. The ENERGY STAR fixture offer appears to be in the early adopter stage. Relatively few residential customers were aware of, or had purchased, these fixtures. To accelerate adoption, consider reviewing the approach used to promote ENERGY STAR fixtures.
4. The evaluated estimate of market effects due to program efforts on LED lamps may reflect an acceleration of the LED market and may therefore be transitory. It is not recommended that the market effects estimate presented in this evaluation be applied as is to forecast or reported program savings beyond F2014.
5. Consider the need for and costs of an updated lighting load shape and hours-of-use metering study of BC Hydro customers.

2.5 Conclusions

From F2013 to the end of the first quarter of F2015, BC Hydro's residential lighting program saved 58.4 GWh/year of electric energy, mostly due to LED lamps. Since its inception in 2002, the program has had widespread effects on the residential lighting market in BC Hydro's service territory, resulting in an increase in awareness, installations and purchases of energy-efficient lighting products.

3.0 Continuous Optimization F2011-F2013

3.1 Introduction

Section 3.0 presents an impact evaluation of electricity savings due to BC Hydro's Continuous Optimization (**C.Op**) demand side management (**DSM**) program for fiscal years F2011 to F2013 (from April 1, 2010 through March 31, 2013). This evaluation also includes elements of a process and market evaluation.

The Continuous Optimization program began in 2009 to help commercial building owners and operators implement and maintain improvements to their energy management practices. The key focus of the program is operational conservation measures, which are often referred to as "low/no-cost" because implementation does not require the purchase and installation of new equipment, and costs are generally limited to labour. The conservation potential for operational savings in a commercial building is largely tied to improving the performance of the building's heating, ventilation and air conditioning (**HVAC**) systems, as well as lighting and refrigeration systems.

Program access was available to commercial buildings larger than 50,000 square feet and since 2010, over 500 buildings enrolled in the program, with the majority of these buildings continuing through the program stages and components further described below. Program participants have been diverse, including the following commercial segments: offices, retail, healthcare, education, hospitality and recreation. As of September 2013, the program had reached its participation goals with an estimated 35 per cent of the eligible buildings participating. The program was then considered fully subscribed and no longer accepting new applications.

The program consisted of two primary components which were fully funded by the program:
1) recommissioning the building and 2) installing an Energy Management Information System (**EMIS**).

In the recommissioning component, consultants worked with customers to identify and implement energy conservation measures, and customers were required to implement the recommended measures with simple paybacks under two years. Each customer engagement lasted up to five years, requiring ongoing customer interaction, document reviews and administration. The main steps of the recommissioning component were: studying the building, recommending low- or no-cost energy efficiency improvements, reviewing the energy conservation measures with operations staff, implementing measures, validating implementation of measures through site inspections, and conducting follow-up coaching sessions to ensure energy savings continue.

The EMIS component was an energy information tool that took interval data from the customer's whole building meter and provided analysis and reporting on the building's energy use. If the customer's utility meter measured the consumption of the whole building, BC Hydro upgraded the meter to a pulse output meter at no cost to provide the interval data. Where the utility meter did not provide whole building data, such as with large university campuses, the customer was obligated to provide their own meters to provide the interval data. The EMIS vendors then installed the EMIS and configured it to provide information allowing building operators to identify processes that had a substantial impact on energy consumption and provided a good opportunity for energy savings. The original program intent was to use the EMIS functionality for quantifying energy savings, exception reporting (a "heads up" when building consumption is unexpectedly high), load profiles, benchmarking, and billing analysis.

3.2 Approach

Four evaluation objectives were identified, each with specific researchable questions, as summarized in the following table:

Table 3. 1. Evaluation Objectives and Research Questions

Evaluation Objective	Research Questions
1. Assess program participation and energy conservation measures	• What were the most common types of participating buildings? • What were the most commonly implemented recommissioning measures? • What were the implementation rates of the various recommended measures? • How did implemented measures perform relative to expectations?
2. Understand the participant experience	• How aware are participants of key program components? • To what extent do participants' understandings of the purpose and operation of key program components match their actual purpose and operation? • How early following program enrolment did participants start to implement recommissioning measures? • What is the qualitative assessment of free ridership?[1] • To what extent did participants implement recommissioning measures at buildings that were not enrolled in the program (participant spillover)? • To what extent did participants implement hard-wired energy conservation measures as a result of the program?
3. Explore market effects and program influence	• To what extent did the number of active EMIS customers change? • What were the noticeable changes to building operating practices? • What evidence exists regarding the extent to which the above changes would have occurred in the absence of the program? • To what extent did implementation of EMIS systems and/or recommissioning studies occur outside the program?
4. Estimate net savings	• What are net electric energy savings? • What are net peak demand savings? • What is the approximate profile of energy savings during the BC Hydro system peak? • Do energy savings vary by season? • What evidence is available on savings persistence?

Table 3.2 summarizes, for each of the evaluation objectives, the evaluation data and methods used.

Table 3.2. Evaluation Objectives, Data Sources and Methods

Evaluation Objectives	Data	Method
1. Assess program participation and energy conservation measures	• Program tracking data • Project files • Measurement and Verification (**M&V**) reports	• Engineering desk review • Trends analysis
2. Understand the participant experience	• Participant interviews (22 organizations interviewed)	• Qualitative analysis
3. Explore market effects and program influence	• EMIS Vendor Interviews (3 organizations interviewed) • Recommissioning consultant interviews (5 organizations interviewed)	• Qualitative analysis
4. Estimate net savings	• EMIS hourly electricity data during F10-F15 • Program tracking data • Hourly weather data	• Quasi-experimental design: Variation in Adoption; ANCOVA statistical analysis

[1] A quantitative assessment of free ridership was not completed because the evaluation method used in Objective 4 to estimate net savings produces a direct estimate of net savings accounting for any free ridership. As a result there was no business need for a stand-alone free ridership estimate.

The first objective, related to assessing program participation and energy conservation measures, was completed using engineering desk reviews and trend analysis using three data sources: program tracking data, project files and M&V reports.

The second and third objectives, related to understanding the participant experience and exploring market effects and program influence, were addressed with qualitative research in the form of semi-structured interviews with program participants, recommissioning consultants and EMIS vendors. The twenty two participant interviewees represented 340 buildings that were enrolled in the program. The three EMIS vendors who were interviewed represented all EMIS vendors involved in the program. The five recommissioning consultants interviewed were estimated to have to have provided C.Op services to over 200 buildings that were enrolled in the program. The interviews lasted 45 to 90 minutes each, were conducted from January through March 2016 either in-person or via telephone.

The fourth objective, related to net savings, was addressed by conducting a statistical analysis of the 433 participating buildings for which quality data were available. The analysis involved five steps: 1) obtain hourly consumption and program tracking data and prepare it for analysis, 2) group the buildings by load shape, 3) set up a quasi-experiment, 4) model program effects, and 5) calculate net electricity savings. This evaluation method produces a reliable estimate of average net savings per participant. Note that the use of the EMIS modelling functionality, as well as the completion of a representative sample of M&V, were both considered for the evaluation of net savings, but were abandoned due to the cost and time involved in implementing these methods.

The method for estimating net electric energy savings was used to provide some insights into savings persistence, the average daily shape of savings and savings seasonality. Peak demand savings were calculated using the evaluated savings shape.

3.3 Results

Results for Objective 1: Program Participation and Energy Conservation Measures

Program tracking data for F2011 to F2013 revealed that four customer segments accounted for over 80 per cent of participating buildings and 77 per cent of expected savings: universities/colleges, offices, schools and hospitals. Buildings participating in the program achieved energy savings by implementing energy conservation measures related to building operations, with the most common being: reduction in excessive equipment operation (38 per cent of total measures implemented), building systems controls optimization (18 per cent) and equipment load reduction or efficiency increase (15 per cent). The majority of the energy conservation measures focused on four building systems: ventilation (67 per cent), lighting (11 per cent), boiler plants (9 per cent) and chiller plants (6 per cent).

Overall, 75 per cent of all energy conservation measures recommended by the recommissioning consultants were implemented at participating buildings. Energy conservation measures with implementation rates of 70 per cent or higher commonly involved changes to building management systems and, as such, aligned with the program intent to promote implementation of operational measures. Energy conservation measures with lower implementation rates commonly had higher capital costs and, as such, did not align with the program intent to target operational measures, but their recommendation by recommissioning consultants was not discouraged.

One of the program goals was to use the EMIS functionality for quantifying energy savings to measure savings for the program overall. That goal was ultimately not achieved because collecting and maintaining the required data was challenging for some participating buildings, and completing the required detailed investigation to validate the EMIS savings estimates was costly and slow. The EMIS did measure savings in some buildings as intended.

Ten of the buildings were selected for a detailed investigation of energy savings, using M&V. These ten buildings were selected because they appeared to have the appropriate conditions for successful application of M&V. These ten buildings are not representative of all buildings in the program and results of their M&V were not used in the estimation of net program savings presented in this evaluation. Verified savings for the ten buildings were compared to the expected savings developed by the recommissioning consultant. Across the 10 projects, the median of verified savings was 82 per cent of expected savings.

Results for Objective 2: Understand the Participant Experience

In general, there was a high level of awareness and understanding of the program among participants. Participants generally understood most of the key program milestones, and their understanding of program components generally matched the actual purpose and operation of those components. However, there was a greater range in the understanding of the role of the coaching phase, particularly between recommissioning consultants and participating customers. Experience with the individual program milestones was generally positive with the exception of the coaching phase where feedback varied widely. Overall satisfaction with the program was high with participants, consultants and EMIS vendors all reporting a very positive experience with the C.Op program.

The qualitative research suggests that minimal free ridership occurred in the C.Op program. Participants reported that little to no recommissioning measures would have been implemented without the program's support. Likewise, the recommissioning consultants reported minimal recommissioning activity before the program and minimal activity outside of the program during its operation. Although the incidence of spillover was noted to be widespread among participants and by consultants, it typically occurred at buildings that were too small to participate in C.Op or were located in regions outside B.C. (among national chains), suggesting the magnitude of spillover from this particular program within B.C. was generally small.

Results for Objective 3: Explore Market Effects and Program Influence

Multiple participants highlighted the importance of C.Op in increasing building operators' awareness of the performance of their facilities, and that checking performance with EMIS was now part of the operators' weekly activities. Many participants also noted that positive organizational changes had occurred as a result of participation, such as providing the structure for Energy Managers to work more closely with building operational staff. The EMIS also provided a tool to communicate energy performance to operators and senior managers, increasing their awareness of energy conservation and interest in making further improvements. However, there was significant variation in the reported level of engagement by operational staff.

Only a few participants owned or were even aware of the existence of EMIS prior to participation in C.Op. The EMIS vendors reported that the market for EMIS grew significantly in B.C. from the beginning of the C.Op program up to 2012 after which it plateaued, and they attributed this growth to the C.Op program. All consultants were of the opinion that there was limited recommissioning before C.Op and the market developed rapidly for recommissioning services while C.Op was in place, with the majority of this growth directly from C.Op participation. Participants expressed some uncertainty about their organizations' willingness to pay for an EMIS or for recommissioning consultants without utility funding.

Results for Objective 4: Estimate Net Savings

Results for electric energy and peak demand savings are summarized below. Results are cumulative. This means that the annual savings results include any savings achieved in earlier years that continue to persist. Values presented in the rows of the table below should not be summed.

Table 3.3. Summary of Electric Energy and Peak Demand Savings

Fiscal Year	Cumulative Energy Savings (GWh/year)		Cumulative Peak Demand Savings (MW)	
	Reported	Evaluated Net	Reported	Evaluated Net
F2011	3.3	0.0	0.5	0.0
F2012	10.7	32.4	1.5	3.7
F2013	21.6	36.5	3.0	4.2

As shown, evaluated net savings were 36.5 GWh/year by F2013, which was 171 per cent of reported. Evaluated net savings of 32.4 GWh/year in F2012 and 36.5 GWh/year in F2013 are equivalent to average annual savings per participant of 4 per cent and 5 per cent, respectively.

Analysis of changes to savings over time among the earliest participating buildings showed that an increase in savings was observed from F2011 through F2015, supporting the hypothesis that gross savings persist for at least four years. Most program savings were achieved between 7 a.m. and 7 p.m., with peak savings occurring at 11 a.m. C.Op participants achieved greatest savings during the summer season, followed by the winter season.

3.4 Findings and Recommendations

Findings

Listed below are the main findings of this study.

1. The most common energy conservation measure was to limit mechanical or lighting systems that ran longer hours than needed and ran during unoccupied periods. The majority of the energy conservation measures acted on four building systems: ventilation (67 per cent), lighting (11 per cent), boiler plants (9 per cent) and chiller plants (6 per cent).
2. Program participants had a high level of awareness and understanding of key program milestones and a generally accurate understanding of the purpose and operation of the program's components, with the exception of the coaching phase. The coaching phase also had the most varied levels of satisfaction.
3. Overall, participants, consultants and EMIS vendors reported having a very positive experience with the C.Op program. Participants also expressed very strong commendations to BC Hydro staff for designing and implementing a sound program.
4. The qualitative research suggests that program free ridership was minimal. Although the incidence of spillover was widespread among participants, it generally occurred at buildings that were too small to participate in C.Op or that were located outside of B.C., suggesting the overall magnitude of spillover in B.C. was small. Note that the net evaluated savings in this evaluation account for free ridership and spillover at participating sites.
5. Evidence suggests that suitable assignment of roles and responsibilities, including responsibility for energy management, among employees of participating organizations is a success factor for the C.Op

program. The impact analysis suggested that C.Op participants with a dedicated energy manager in place may have responded faster to the program than did participants without this position. The qualitative research revealed that although positive organizational changes had occurred at many organizations as a result of participation in the program, there was significant variation in the reported level of engagement of operational staff. Many organizations reported that engaged building operators were a key ingredient in achieving program goals, but the operators were too busy keeping the building running, were not concerned with energy efficiency or did not have sufficient training.

6. Consultants and participants expressed the importance of maintaining utility involvement in supporting recommissioning because many felt that operating practices may revert to pre-program levels in the absence of a utility-sponsored program.
7. Evaluated net savings were 36.5 GWh/year by F2013, which was 171 per cent of reported. The primary cause of the positive variance was that savings were achieved earlier than anticipated. Average net weekday savings per participant were between 4 per cent and 5 per cent, which aligns with program expectations. Savings were greater on weekdays than weekends and holidays. They were also greater during the daytime than overnight and during summer and winter than during shoulder seasons.
8. There was variation in the speed with which participants responded to the program and started to achieve savings. Universities, hospitals and hospitality buildings responded faster than did office buildings. C.Op program participants who were concurrently enrolled in another BC Hydro DSM program responded to the C.Op program faster than did those who were not.
9. The original program goal to verify program energy savings by aggregating EMIS savings estimates across participating buildings was not achieved. The EMIS savings estimates commonly had large and unexplained variances from the engineering estimates developed by the recommissioning consultants.
10. Ten buildings with suitable energy consumption and savings patterns were selected for detailed investigation using Measurement and Verification techniques. Across the 10 buildings, the median of verified savings was 82 per cent of expected savings.
11. The statistical analysis of net savings used hourly electricity consumption data collected through the EMIS. Customers and stakeholders suggested using smart metering infrastructure (**SMI**) data instead. However, SMI data would not be feasible for many participants as they operate campuses where a single utility meter covers many buildings, and not all buildings participate in the program.
12. With the trend of decreasing participation due to the program being fully subscribed, the Variation in Adoption approach applied in this impact study may not be feasible for the next impact evaluation.
13. This evaluation relied on electricity consumption data collected through the EMIS. EMIS vendors started collecting these data in 2011. BC Hydro did not request the data until 2015. This lag delayed the evaluation analysis and led to challenges in data availability and quality.

Recommendations

Listed below are recommendations resulting from this study, starting with recommendations for program management followed by a recommendation for future evaluations.

Recommendations for program management:

1. Consider shortening the timing between the installation of the EMIS and the reporting of savings.
2. Continue to collect building-level hourly electricity consumption data for participants to ensure the feasibility of future impact analysis given the limitations of SMI data.
3. If coaching is offered in the future, review the objectives of this component and strengthen its delivery.
4. Develop a better understanding of building operators' responsibilities, capabilities and training needs in order to better support their role in the program.
5. Some participants indicated that they may need to have the buildings go through the recommissioning process again in future as operating practices may revert to pre-program levels in the absence of the program. Therefore, the program may consider investigating the need for repeat recommissioning of participating buildings in future.

Recommendations for future evaluations:

6. Evaluation should collaborate with program management to explore, investigate and design alternative evaluation methods for future evaluations given changes in program participation trends.
7. Centralize storage and management of the EMIS data to facilitate its use in future evaluations and program administration.

3.5 Conclusions

The Continuous Optimization program was successful in achieving energy savings through building recommissioning. Evaluated net savings were 36.5 GWh/year by F2013, which was 171 per cent of reported. Program participants expressed high levels of satisfaction with the program and reported a range of organizational benefits in addition to energy savings.

4.0 High Performance Buildings and Commercial New Construction: F2008-F2011

4.1 Introduction

Section 4.0 presents an impact evaluation of net electricity savings achieved by BC Hydro's High Performance Building program and its successor the Commercial New Construction program for BC Hydro fiscal years F2008 through F2011 (from April 1, 2007 through March 31, 2011), as well as elements of a process and market evaluation. The objective of these programs (collectively referred to as the CNC program) was to accelerate the demand for and construction of energy efficient commercial buildings.

The CNC program was targeted at developers and market actors who play a role in building and expanding commercial buildings in BC Hydro's service territory. Market actors included developers, building owners, architects, engineers and consultants. The five key objectives of the CNC program were as follows:

1. Energy Efficient Design: Create energy savings by promoting the design of energy efficient buildings.
2. Energy Efficient Construction: Create energy savings by promoting the construction of energy efficient buildings.
3. Energy Efficient Operation of New Commercial Buildings: Create energy savings by providing education and support to properly operate new buildings as they were constructed and designed.
4. Training and Recognition: Enable transformation of the market by training a team of industry professionals to act as energy efficiency and conservation advocates on all new construction projects that they work on in the future. In addition, publicly recognize energy efficient design teams and projects and create a market where consumers demand energy efficient buildings.
5. Advance Building Codes: Support the transformation of the new building market to higher sustained levels of energy efficiency and improved building code compliance. Move the market towards more efficient design so that government can increase the energy efficiency requirements in the BC Building Code and Vancouver building by-law.

As noted in the fifth key objective above, the program was designed to support increases in the energy efficiency requirements in building codes. Notable changes in this regard were the 2008 and 2013 updates to the BC Building Code and Vancouver Building by-law.

4.2 Approach

Shown below are the evaluation objectives and research questions, followed by the data sources and methods.

Table 4. 1. Evaluation Objectives and Research Questions

Objectives	Research Questions
1. Assess participant experience	• What is the level of participant awareness of the various CNC program components? • How do participants rate their program experience and overall satisfaction? • How influential is the CNC program on participant decisions around energy efficiency?
2. Assess trends related to market transformation	• To what extent has the CNC program developed support for design and construction of more energy efficient buildings (beyond code requirements) among designers and builders? • How is the CNC program influencing building design practices and the new construction market, even beyond incented projects? • Did the program help designers and builders prepare for changes in the building code (2013 changes) and help improve compliance rates?
3. Assess the influence of the program on compliance and adoption of building code energy efficiency requirements	• To what extent did the CNC program influence increased compliance with the 2008 BC Building Code and City of Vancouver Building Bylaw? • To what extent did the CNC program influence the adoption of the 2013 building code by “readying the market”?
4. Estimate gross energy and peak savings	• What are gross energy and peak savings?
5. Estimate net energy and peak savings	• What are the free-ridership, participant spillover and non-participant spillover rates? • What are the net energy and peak savings for the overall CNC program?

Table 4.2 summarizes, for each of the evaluation objectives, the evaluation data and methods used.

Table 4.2. Evaluation Objectives, Data Sources and Methods

Objectives	Data sources	Method
1. Assess participant experience	• Participant survey (n = 25)	• Cross tabulations
2. Assess trends related to market transformation	• Market actor survey (15 participants and 9 non-participants)	• Cross tabulations
3. Assess the influence of the program on compliance and adoption of building code energy efficiency requirements	• Market actor survey (15 participants and 9 non-participants) • Interviews with program staff • Program documentation • Program tracking data • Expert opinion	• Delphi method
4. Estimate gross energy and peak savings	• Program tracking data • Measurement and verification (n = 14)	• IPMVP Options A, B and D • Probability Proportional to Size (PPS) ratio estimation • Peak demand savings based on peak-to-energy factor
5. Estimate net energy and peak savings	• Statistics Canada data on commercial new construction activity, F2008-F2011 • Participating building area (sq. meters) • Workshop with program administration • Results from Objective 4 • Participant survey (n = 25) • Market actor survey (15 participants and 9 non-participants) • Project files (n = 7)	• Survey based free ridership and participant spillover algorithms • Case study free ridership assessment

The first objective regarding participant experience was evaluated using the results of detailed online survey of participants delivered in spring 2013. Participants were defined as the individuals who entered into the funding agreement with the CNC program, and they most commonly held the titles project manager, property manager, developer or general manager. The total population of participants over the four years evaluated was 131. A total of 25 surveys were completed by program participants out of 73 sent.

The second objective regarding market transformation was evaluated using the results of a telephone survey of market actors delivered in February 2014. Market actors included engineers, architects, developers, energy modellers and project managers who played a role in decisions related to new construction and design. Fifteen participants and nine non-participants completed the survey.

The third objective regarding the influence of the program on building codes was evaluated using the results of a Delphi panel. The Delphi panel was made up of four local professionals and four experts residing outside B.C. The panelists were provided the results of the market actor survey, along with summary and background information on the program. The panelists first provided their responses to a questionnaire, along with an explanation behind their answer. Panelists then reviewed the results and explanations provided by their peers and had an opportunity to change their initial responses. Results were scored to produce metrics related to the program influence on the building code.

The fourth objective regarding evaluated gross savings was conducted using the results of M&V of a sample of participating buildings.[2] Nine buildings underwent Option D M&V,[3] which involves calibrated energy modelling

[2] In some cases a "building" encompassed a development made up of several parcels.
[3] As defined in the International Performance Measurement and Verification Protocol (**IPMVP**).

of an entire building, informed by energy consumption data as well as sub-metering data of individual building systems. Five buildings underwent Option A or B M&V, which involves energy calculations informed by measured results for power or hours of use. The M&V sample was designed to provide high coverage of the population in terms of energy savings, and to be representative of the population overall on that basis. The final M&V sample coverage from the 14 buildings that underwent M&V was 33 per cent of electric energy savings and 58 per cent of building area. M&V results were extrapolated to the population of all 131 participating buildings using a statistical technique called probability proportional to size ratio estimation.

The fifth objective regarding evaluated net savings, relied on the results of objective four, evaluated gross savings, as well as free ridership and participant spillover estimates derived from the participant survey described above.

4.3 Results

Results for Objective 1: Participant Experience

Awareness of the CNC program was very high among program participants at 96 per cent. Those who were aware were asked additional questions about three individual program components: the energy study, the incentive structure and the Key Account Managers role as liaisons for the program.

Seventy-four per cent of participants were aware of the basics of the energy study component of the program. Among those aware of energy studies, 61 per cent gave it positive ratings overall, and the majority (59 per cent) gave it only a ‘fair’ rating for being easy to work with and act upon, rather than an excellent (11 per cent) or good (25 per cent) rating.

Sixty-eight per cent of participants were aware of the project incentive structure of the program. Among those aware of the incentive structure, 94 per cent gave it positive ratings overall, while 61 per cent provided positive ratings for it being easy to work with and understand.

Seventy five per cent of participants were aware of Key Account Managers (**KAMs**) in general, and among those who were, all were aware of the role that KAMs play as a liaison between the CNC program and its participants. Among those who were aware of the KAM role, 100 per cent gave it positive ratings both overall, and for being easy to work with.

Among program participants, overall satisfaction with the CNC program was very high with 95 per cent of participants reporting that they were either ‘very satisfied’ (65 per cent) or ‘somewhat satisfied’ (30 per cent) with the program. In total, 100 per cent would ‘definitely’ (70 per cent) or ‘probably’ (30 per cent) recommend the program to others and in fact, 54 per cent reported already having done so.

Results for Objective 2: Market Transformation Trends

Nineteen of the 24 respondents to the market actor survey said that some portion of their buildings met or exceeded the new energy efficiency requirements in the building code prior to their introduction in December 2013. Those who indicated a portion of their buildings were meeting or exceeding the 2013 code before it took effect were asked how influential the CNC program was in this achievement. Six of the 12 participant respondents said very influential. Five of the seven nonparticipants reported the program was at least somewhat influential, and one stated it was very influential.

If the CNC program had not been in place, eight of the 24 of the respondents said overall building code compliance would have been lower in British Columbia and ten of the 24 stated that compliance would have been lower in Vancouver. Of those that thought the program affected code compliance, six of eight estimated that the program improved compliance by 20 per cent or less.

Participating market actors were asked if what they learned through the CNC program helped them comply with the building code, even on projects that did not receive a program incentive. Close to half of respondents said yes. These respondents said that the lessons learned from projects that went through the program were so useful and meaningful that they utilized this new knowledge whenever possible, even on projects outside of the program.

Results for Objective 3: Program Influence on Compliance and Adoption of Building Code Energy Efficiency Requirements

The Delphi panelists showed strong consensus around the importance of the market drivers that were identified for "Improving Compliance." All eight panelists reported that two drivers of improved compliance, "Market Awareness of Code Requirements" and "Market Awareness of Strategies and Skills to Meet Code" were *very important*.

After reading information about BC Hydro's activities related to improving compliance with the previous code, the panelists were asked to "rate the program's influence using a zero to ten scale, where zero means the program had no influence and nine means the program was very influential." Ten on the scale meant the program was so influential that it should claim all the credit (100 per cent attribution). No panelists made that determination. Panelists rated the program's influence to be greatest on the "Availability of Tools and Technologies to Demonstrate Compliance", with a mean rating of 7.6.

Table 4.3: Influence Ratings for Market Drivers of Improving Compliance with ASHRAE 90.1-2004/2007

	Market Awareness of Code Requirements	Market Awareness of Strategies and Skills to Meet Code	Availability of Tools and Technologies to Demonstrate Compliance
Mean	6.8	5.6	7.6
Mode	8	5	9
Range	5 to 8	3 to 8	5 to 9

Panelists rated the CNC program's influence on "Market Awareness of Code Requirements" as the next most influential, with a mean rating of 6.8 and four panelists providing a rating of eight. These panelists reported that they believed the program was critical to educating market actors about the code. Those who provided a lower rating noted that while the program did have a role in educating the market, it seemed the program's reach may have been low, or that other initiatives or organizations (such as LEED, the City of Vancouver, and others) were similarly engaged on this topic, and thus the contribution of the CNC program was simply one part of a much larger effort.

Panelists were also asked to rate the importance of market drivers that ready the market for the next iteration of the building code. The majority of respondents felt the identified drivers for readying the market for the 2013 update to the building code (ASHRAE 90.1-2010) were *somewhat important*. According to panelist feedback, having sufficient technical workforce capacity to design and construct buildings to meet the new code requirements was the most important driver, with three panelists reporting this as *very important* and five reporting it as *somewhat important.*

Panelists rated the program's influence on each market driver using a scale from zero to ten. Panelists rated the program's influence to be greatest on the "Technical Workforce Capacity", with a mean rating of 6.4.

Table 4.4: Influence Ratings for Market Drivers of Readying the Market

Readying the Market for the Adoption of ASHRAE 90.1-2010			
	Industry Awareness and Buy-in	**Technical Workforce Capacity**	**Availability of Tools and Technologies to Demonstrate Compliance**
Mean	5.5	6.4	5.1
Mode	5	5	2
Range	4 to 7	2 to 9	2 to 9

There were two drivers where panelists did not converge on the program's influence. These were "Technical Workforce Capacity" and "Availability of Tools and Technologies to Demonstrate Compliance" where panelists' influence ratings ranged from two to nine.

Generally, results from the Delphi panel point to a moderate influence of the program on both improving compliance with the 2008 BC Building Code as well as readying the market for subsequent code revisions in 2013.

Results for Objective 4: Evaluated Gross Electricity and Peak Demand Savings

The evaluated gross electric energy savings and peak demand savings for the CNC program from F2008 to F2011 are 48.6 GWh/year and 6.7 MW, versus the expected savings of 50.4 GWh/year and 7.0 MW. The variance between expected and evaluated gross savings is due to the program realization rate being 97 per cent. Common reasons for the variance included differences between expected and verified plug loads, operating hours, fuel mix and building envelope characteristics.

Results for Objective 5: Net Electricity and Peak Demand Savings

Evaluated net savings are summarized below.

Table 4.3: Summary of Energy and Peak Demand Savings

Fiscal Year	Energy Savings (GWh/year)		Peak Demand Savings (MW)	
	Reported	Evaluated Net	Reported	Evaluated Net
F2008	3.6	2.4	0.5	0.3
F2009	10.2	7.5	1.4	1.0
F2010	25.9	17.2	3.6	2.4
F2011	9.5	6.9	1.3	1.0
Sum of F2008-F2011	**49.2**	**34.0**	**6.8**	**4.7**

Free ridership was 31 per cent, which was higher than expected and is the reason for the negative variance between reported and evaluated savings. Participant spillover was 1 per cent.[4] Due to data limitations, a point estimate of non-participant spillover could not be produced, and non-participant spillover is not included in the net evaluated savings. Evidence collected through this evaluation suggests non-participant spillover occurred and may have been substantial.

[4] Participant spillover was defined as additional energy savings measures implemented in participating buildings, but outside the program. Because the program targeted whole building energy efficiency, participant spillover was expected to be small.

4.4 Findings and Recommendations

Findings

Key findings of this evaluation are summarized below:

1. Among program participants, overall satisfaction with the CNC program was very high with 95 per cent of participants reporting that they were either very or somewhat satisfied with the program. All surveyed participants said they would definitely or probably recommend the program to others. In fact, 54 per cent reported already having done so.

2. The aspects of the program experience that rated the highest included ‘service provided by BC Hydro’, ‘information about CNC on the website’, ‘service provided by contractors’ and ‘level of incentives offered’. Aspects which rated the lowest include ‘length of time for the project to be completed’, ‘the variety of products funded under the program’, and ‘length of time to receive the incentive’.

3. Eighty nine per cent of participants reported that the program was either ‘very influential’ or ‘somewhat influential’ on their decision to implement the energy efficient measures.

4. Responses from market actors, as well as the Delphi panel, indicate that the CNC program likely improved compliance with historical BC and Vancouver building codes. The majority of respondents said the program helped improve the compliance through financial assistance, technical assistance, or quality assurance for design and installation in participating buildings. The experts who participated in the panel rated the program favorably in terms of its effect on compliance.

5. Market actors as well as the Delphi panel found the CNC program had some influence on readying the market for the 2013 building code update. Market actors said the program was influential in helping them understand the 2013 code prior to enactment and also in building and designing buildings that met (or exceeded) the 2013 code before it went into effect, indicating that the program helped ready the market for the adoption of the regulation.

6. Measurement and verification of 14 buildings (or development parcels) revealed that most realized savings that were substantially different from expected levels. One reason for this variance was that program rules for the treatment of fuel switching were not well defined until the later part of the evaluation analysis time frame and as a result the verified fuel mix was sometimes different than expectation. Other reasons included differences in operating hours, plug load, and building envelop characteristics. These variances tended to cancel each other out, and the overall realization rate across all buildings that underwent M&V was 97 per cent.

7. The net-to-gross ratio was 70 per cent, made up of 31 per cent free ridership and 1 per cent participant spillover. Cumulative evaluated net savings from F2008 through F2011 were 34.0 GWh/year, which is 70 per cent of reported savings of 49.2 GWh/year. Free ridership was higher than expected, in part because of some of the highest saving buildings in the early part of the evaluation analysis time frame were large, high profile buildings where government and public expectation played a substantial role promoting energy efficient building design. Such buildings became less common in the later part of the evaluation analysis time frame.

8. Evidence suggests that non-participant spillover occurred during the evaluation period. However a reliable point estimate could not be produced due to data limitations. Estimates of non-participant spillover ranged from 3 per cent to 18 per cent of evaluated gross savings. Due to the high level of uncertainty, non-participant spillover is not included in the net evaluated savings estimate.

Recommendations

Recommendations from this evaluation are shown below.

1. The free ridership rate of 31 per cent presented in this evaluation was based on projects and decision making for the time period up to F2011 and may not be suitable to use for program planning and reporting purposes outside this period.

2. Given the evidence that non-participant spillover occurred, consider designing and implementing a survey of a representative, randomly selected cross section of non-participating market actors to produce an updated estimate of program effects on non-participants. The data collected should allow for the estimation of any attribution of non-participant energy efficiency savings to the CNC program, and for the estimation of the proportion of the non-participating commercial new construction market influenced by the program.

3. To achieve cost savings in future M&V, consider obtaining and retaining the participating building design and modelling files as a condition of incentive approval.

4.5 Conclusions

The Commercial New Construction Program achieved very high participant satisfaction. Cumulative evaluated net savings from F2008 through F2011 were 34.0 GWh/year, which is 70 per cent of reported savings. Evidence suggests that the program played a role readying the market, and improving compliance, with the energy efficiency requirements of the BC and Vancouver building codes.

5.0 Power Smart Partner - Transmission: F2012-F2014

5.1 Introduction

Section 5.0 presents an impact evaluation of the BC Hydro Power Smart Partner – Transmission (**PSP-T**) DSM program for BC Hydro fiscal years F2012 to F2014 (April 2011 to March 2014). This evaluation also includes elements of a process and market evaluation.

BC Hydro's Power Smart Partner – Transmission Program (renamed Leaders in Energy Management – Transmission in 2015) is a multi-year energy acquisition and market transformation initiative that encourages large industrial customers, which receive electricity supply at transmission voltage, to reduce their electricity consumption. The program's target market is BC Hydro's 75 industrial transmission customers (with facilities at 174 sites). The key program objective during the period evaluated was to partner with program participants to obtain cost-effective electricity savings by encouraging them to integrate energy efficiency into their on-going business practices and supporting them to respond to the conservation price signal delivered by the Transmission Service Rate (**TSR**). This evaluation evaluates the combined effect of the program and rate for energy efficiency and conservation projects reported through the program.

The scope of this evaluation includes electrical energy efficiency and conservation projects at industrial transmission service sites. Facility wide savings resulting from strategic energy management efforts are not included in the scope of this evaluation as they were not reported by the program during the evaluating period. This encompasses the incentive offer and enabling activities, as further described below. During the three-year evaluation timeframe, 145 energy efficiency and conservation projects were completed at 57 sites and reported under the program. Program participants included the following industrial segments: pulp & paper, mining, wood, oil & gas, chemicals, cement and transportation. The program reported projects in various end uses with a primary focus on industrial process energy efficiency improvements. The main program components and enabling activities are summarized below:

- **Incentive:** Incentives of up to 100 per cent of project costs were available for custom projects. Since F2014, smaller lighting and compressed air projects were also eligible for prescriptive incentives under the self-serve incentive program (**SIP**).
- **BC Hydro Key Account Managers:** Acted as a liaison between the program and the customer.
- **BC Hydro Alliance of Energy Professionals:** A network of energy efficiency trade professionals registered with BC Hydro, formerly known as Power Smart Alliance.
- **Energy Studies:** Identified and built a business case for the implementation of energy conservation measures; fully funded by BC Hydro.
- **Energy Managers:** Helped participants adopt strategic energy management practices; partially funded by BC Hydro.
- **Strategic Energy Management:** Provided a structured approach to improve energy efficiency, including the use of Energy Management Assessment workshops that scored current energy management practices. Supported development and implementation of energy management systems.

The program relied on two approaches to recognize savings, program enabled and incentive:

- **Program Enabled:** Customer-funded electricity conservation measures that are linked to a program-funded enabling activity such as an energy study or energy manager.
- **Incentive:** Electricity conservation measures that received an incentive from BC Hydro.

5.2 Approach

Shown below are the evaluation objectives and research questions, followed by the data sources and methods.

Table 5. 1. Evaluation Objectives and Research Questions

Evaluation Objective	Research Questions
1. Assess participant and non-participant experience and satisfaction	• What is the participant experience related to awareness, understanding, and satisfaction with the various program offers? • What are the barriers to and drivers of program participation?
2. Assess the Strategic Energy Management initiative	• What was the coverage of energy managers among program participants? Were energy managers associated with increased project activity? • What changes were observed in customer commitment to energy conservation and efficiency over time? How did customer ratings progress in key areas of Energy Management Assessments over time? • What changes were observed in the customer capability of energy conservation and efficiency over time? What changes in energy management practices among participants were observed over time?
3. Assess trends related to market transformation in the industrial sector	• Has the program shifted or transformed the market for energy efficiency services offered by trade allies registered with the BC Hydro Alliance of Energy Professionals? • Over the past five years (2011-2016), how has industry capability to deliver energy efficiency services changed? • Aside from the program, what additional drivers of demand for energy efficiency services exist among industrial customers? How have these drivers changed over time?
4. Estimate gross electrical energy and peak demand savings for incentive and program enabled projects	• What were the most common energy conservation measures by end use and customer site type for incentive and program enabled projects? • What were the evaluated gross energy and demand savings realized by PSP-T incentive and program enabled projects?
5. Estimate net electrical energy and peak demand savings for incentive and program enabled projects	• How much free ridership occurred for program enabled and incentive projects? How much participant and non-participant spillover occurred for the program overall? • What was the attribution of energy savings to the combined effect of the PSP-T program and the TSR? • What were the evaluated net energy and demand savings due to the combined effect of the PSP-T program and the TSR for incentive and program enabled projects?

Table 5.2 summarizes, for each of the evaluation objectives, the evaluation data and methods used.

Table 5.2. Evaluation Objectives, Data Sources and Methods

Objectives	Data sources	Method
1. Assess participant and non-participant experience and satisfaction	• Participant Survey (n = 28 responses covering 46 projects) • Non-Participant Survey (n = 25)	• Cross tabulations
2. Assess the Strategic Energy Management initiative	• Program tracking data • Project file reviews of four participants	• Trends analysis • Qualitative analysis
3. Assess trends related to market transformation in the industrial sector	• Trade ally interviews (11 interviews)	• Qualitative analysis
4. Estimate gross electrical energy and peak demand savings for incentive and program enabled projects	• Program tracking data • TSR tracking data • Site visits, file reviews • Measurement and Verification (n = 67) • Energy studies (n = 90)	• Engineering algorithms • Extrapolation of measurement and verification using stratified ratio estimation • Rate class average peak-to-energy factor
5. Estimate net electrical energy and peak demand savings for incentive and program enabled projects	• Results of Objective 4 • File reviews • Participant surveys (n = 28 responses covering 46 projects) • Case Studies (n = 46 projects)	• Triangulation of case study and survey based free ridership estimates • Survey based spillover algorithm • Cross tabulations • Rate class average peak-to-energy factor

5.3 Results

Results for Objective 1: Participant and Non-Participant Experience and Satisfaction

As expected, PSP-T program awareness was very high among participants, with 96 per cent indicating that they were aware of the program by name. Awareness among non/partial participants was somewhat lower, although still high, at 84 per cent. In terms of individual program components, for participants, awareness was highest for the role that Key Account Managers play as liaisons for PSP-T, energy studies and the incentive structure. Non/partial participants expressed high awareness of Key Account Managers and energy studies, but only moderate to low awareness of other program components. With the exception of training and funding for energy managers, participants expressed high levels of understanding with all individual program components. Non/partial participants expressed lower levels of understanding, particularly with energy studies and the energy manager component.

Among participants, Key Account Managers' role as liaisons for the program emerged as the highest rated component in terms of satisfaction (92 per cent 'excellent' or 'good'), followed by energy audits/studies (76 per cent). Among non/partial participants, the PSP-T incentive structure was rated the highest (80 per cent), followed much further behind by energy audits/studies (42 per cent).

Overall satisfaction with PSP-T among program participants was high with 89 per cent of participants reporting that they were either 'very satisfied' (58 per cent) or 'somewhat satisfied' (31 per cent) with the program. In terms of program experience, 'service provided by BC Hydro' was the highest rated of all service elements with 85 per cent of participants rating it as either 'excellent' or 'good'. Aspects around timing were rated the lowest of all of the program elements, with favourable ratings of only 39 per cent for 'length of time to receive the incentive' and 35 per cent for 'length of time for the project to be completed'.

Results for Objective 2: Strategic Energy Management Initiative

The strategic energy management initiative provided participants with a suite of tools and offers intended to help them build energy management into their ongoing business practices, thereby reducing operating and maintenance costs and equipment wear. The tools and offers included funding for an Energy Manager position, energy management assessment workshops that ranked participating facility's energy efficiency and provided participants with a follow-up action plan, facility monitoring and modeling, as well as energy studies and incentives.

The evidence reviewed for this evaluation indicates that Energy Managers played an important role in program participation. Coverage of energy managers among program participants was widespread. Of the 57 sites included in the scope of this impact evaluation, 39 had energy managers. Among sites at which one or more incentive projects were implemented, 20 out of 35 had energy managers, covering 64 per cent of incentive gross savings. Among sites at which program enabled projects were implemented, 19 out of 22 had energy managers, covering 85 per cent of program enabled gross savings. During the evaluation period, sites with energy managers completed twice the number of projects per site relative to those without energy managers (on average, three projects versus 1.5 projects).

Qualitative assessment of participant experience and progress in the strategic energy management initiative was conducted for four participants in the following sectors: mining, pulp & paper, wood, and cement. Each of these participants was unique, and the energy management offer was customized to their situation and opportunities. Overall, review of these four participants indicated that they had ongoing, multi-year commitment to energy management, improved their energy management capabilities over time, and adopted new energy management practices. Note that results for these four participants may not be representative of results for other participants in the strategic energy management initiative.

Results for Objective 3: Trends Related to Market Transformation in the Industrial Sector

Market trends related to market transformation were based on interviews with 11 trade allies. The trade ally respondents generally reported that the range of energy efficiency services offered by their firms had not changed due to the program, but with the experience gained through the program their level of services improved. Although energy efficiency services were not generally the main business activity of these firms, conducting the BC Hydro-funded energy studies provided opportunities for business development and improved customer service.

Responses were mixed regarding the extent to which the program led to the development of new or greater subject matter expertise over the past five years. However, most of the respondents felt that BC Hydro-funded energy studies had supported knowledge transfer among multiple groups (e.g., program technical experts, trade allies, participants and non-participants), in particular regarding analytical methods and methodologies of energy engineering that could be applied to other studies that are not funded by BC Hydro. Most interviewees noted that they rarely, if ever, received information about whether projects performed as expected and saw this as a missed opportunity to expand their expertise and improve future energy studies.

Respondents were largely of the opinion that energy studies made customers aware of new options for energy efficiency that they had not previously been aware of. However, responses varied regarding whether energy studies were motivated by energy efficiency versus other factors such as capacity, de-bottlenecking, quality, etc. About half of the respondents noted that risk avoidance was a much more important factor for customers when considering energy efficiency upgrades than any incentive amounts received or potential energy savings. Changes in customer knowledge and engagement were seen as drivers of energy efficiency services, both of which were seen as having improved as a result of the program, particularly the energy manager component.

Results for Objective 4: Evaluated Gross Electricity and Peak Demand Savings

Evaluated gross savings provide an estimate of savings achieved by program participants. Evaluated gross savings are estimated by applying a realization rate to expected savings. An overall realization rate of 0.92 was calculated for the entire evaluation period using measurement and verification results.

Table 5.3. Expected and Evaluated Gross Savings and Demand for All Participants

Period	Number of Projects	Expected Gross Energy Savings (GWh/year)	Evaluated Gross Energy Savings (GWh/year)	Evaluated Gross Peak Demand Savings (MW)
F2012	41	152.3	136.1	15.4
F2013	39	117.6	110.2	12.4
F2014	65	85.1	81.2	9.2

Results for Objective 5: Net Electricity and Peak Demand Savings

Free ridership was estimated separately for the three types of projects reported by the program: incentive, program enabled with an energy study or an energy savings prediction and program enabled without an energy study or energy savings prediction. Free ridership provides an estimate of the proportion of savings that are not attributable to the combined effect of the PSP-T and TSR. Free ridership was calculated by fiscal year. Spillover was estimated for the overall evaluation period only.

Table 5.4. Summary of Energy and Peak Demand Savings

Period	Evaluated Gross Energy Savings (GWh/year)	Evaluated Gross Peak Demand Savings (MW)	Net-to-Gross Ratio	Evaluated Net Energy Savings (GWh/year)	Evaluated Net Peak Demand Savings (MW)
F2012	136.1	15.4	0.82	111.7	12.6
F2013	110.2	12.4	0.90	99.4	11.2
F2014	81.2	9.2	1.08	87.4	9.9

The overall level of free ridership is estimated at 32 per cent, driven by high free ridership among program enabled projects without an energy study or energy savings prediction. Participant spillover was estimated at 18 per cent and non/partial participant spillover was estimated at 5 per cent for a total of 23 per cent. Together they result in a net-to-gross ratio of 91 per cent.

Evaluated net energy savings in each fiscal year were calculated using the gross savings of each project multiplied by the net-to-gross ratio of its project type. Electricity savings are presented as incremental savings achieved within each fiscal year and expressed as an annual rate of savings (also known as run rate savings). Peak demand savings were calculated using the same peak-to-energy factor as for gross demand savings. Because the distribution of project types and energy savings varied by year, so too did the yearly net-to-gross ratios. Years with greater weighting of energy savings from projects that were program enabled without an energy study or energy savings prediction saw a lower net-to-gross ratio, such as F2012 and F2013.

Table 5.5. Comparison of Reported and Evaluated Net Savings

Period	Energy savings (GWh per year)		Peak demand savings (MW)	
	Reported	Evaluated Net	Reported	Evaluated Net
F2012	125.0	111.7	14.1	12.6
F2013	109.6	99.4	12.4	11.2
F2014	77.1	87.4	8.7	9.9

The variance between reported and evaluated net savings is primarily due to the gross realization rate being lower than forecast. The evaluated net-to-gross ratio was found to be similar as forecast.

5.4 Findings and Recommendations

Findings

1. Overall satisfaction with PSP-T among program participants was high with 89 per cent of participants reporting that they were either very or somewhat satisfied with the program. A similar proportion (92 per cent) reported that they would recommend the program to others, and in fact, 46 per cent reported already having done so.
2. Research for this evaluation suggests that beyond incentives, the key aspects of the program's success in terms of satisfaction, engagement and project activity levels include Key Account Managers, energy studies and Energy Managers.
3. Among participants, the factors that emerged as the greatest motivators of conservation were minimizing operating costs, program incentives and cost-cutting measures due to economic conditions.
4. Energy Managers played an important role in program participation. Coverage of energy managers among program participants was widespread, at 86 per cent of projects. On average, sites with energy managers completed twice as many projects per site than did sites without energy managers.
5. Trade allies reported that the level of customer engagement appeared to be heavily linked to the presence of an energy manager at a company. Companies with energy managers were viewed as being much more engaged and knowledgeable than companies without one.
6. The evaluability of the strategic energy management initiative would be improved by the adoption of standardized progress monitoring of program participants, as well as adopting standardized methods for determining energy efficiency savings for strategic energy management initiatives.
7. Trade allies were largely of the opinion that energy studies made customers aware of new options for energy efficiency. Only one out of the 11 respondents felt that customers were typically aware of energy efficiency options prior to having a study done.
8. Trade allies also noted that they rarely, if ever, received information about whether projects performed as expected and saw this as a missed opportunity to expand their expertise and improve future energy studies.
9. The gross realization rate was 92 per cent, indicating that the energy conservation measures largely performed as expected. In general, smaller projects had higher realization rates than larger projects. The most common reasons why measures did not perform as expected were changes in operating conditions and inappropriate baselines.
10. Evaluated gross energy savings averaged 1.1 per cent per year of facility energy consumption across all participants, and project savings per site ranged from less than 1 per cent to over 14 per cent.
11. By including additional data sources in the evaluation review, such as TSR records and customer post-implementation data, the coverage of the gross realization rate sample was doubled from what it would have been with M&V results alone. However, the rigour of the realization rate sample was less than what it would have been with M&V results alone.
12. The overall level of free ridership is estimated at 32 per cent, driven by high free ridership among program enabled projects without an energy study or energy savings prediction. Participant spillover was estimated at 18 per cent and non/partial participant spillover was estimated at 5 per cent for a total of 23 per cent. Together they result in a net-to-gross ratio of 91 per cent.
13. Projects with an energy study or energy savings prediction were found to have a substantially lower level of free ridership than projects without one (18 per cent versus 62 per cent, respectively). The net-to-gross ratio increased over time as more and more projects had an energy study.

14. Most of the participant spillover identified in this report came from sites with an Energy Manager.
15. Evaluated net savings were 111.7 GWh/year in F2012, 99.4 GWh/year in F2013, and 87.4 in F2014, which was 89 per cent of reported savings for F2012, 91 per cent for F2013 and 113 per cent for F2014.

Recommendations

Recommendations for program management:

1. Consider providing information on project performance back to trade allies in order to improve the quality of future energy studies and the recommendations they give to customers.
2. In order to address savings discrepancies due to inappropriate baselines, the program should investigate the merits of reporting for each project the estimated remaining useful life of the baseline equipment.
3. Consider ways to increase the prevalence of energy studies or energy savings predictions among program enabled projects in order to reduce the uncertainty of the counterfactual.
4. In consultation with the evaluation department, consider ways to improve the evaluability of the strategic energy management initiative.

Recommendations for future evaluations:

1. If strategic energy management savings are reported and/or evaluated in the future using a top-down method (i.e., facility-wide regression analysis), consider the extent to which there may be double counting between the participant spillover estimate presented in this evaluation and strategic energy management savings.
2. Consider testing and adopting the Strategic Energy Management Evaluation Protocol currently being developed by the US Department of Energy’s Uniform Methods Project for determining energy efficiency savings for strategic energy management initiatives.

5.5 Conclusions

BC Hydro’s Power Smart Partner – Transmission program achieved 96 per cent of reported savings during F2012 to F2014. The program also achieved high levels of customer awareness and satisfaction.

Glossary

Baseline: A baseline is the initial condition occurring when a DSM activity begins. It may be a market share for equipment, a current standard, or a current average behavior.

Cross Effects: Cross effects (also known as interactive effects) refer to the effect that some energy conservation measures (**ECMs**) have on other electricity end uses beyond what the ECM itself produces. An obvious example is building lighting. As more efficient lighting is installed, less heat is generated by the lighting system. This means that less heat must be removed from the building by the air conditioning system during the cooling season, but more heat needs to be supplied by the heating system during the heating season.

Demand Side Management (DSM): The definition of Demand Side Management is the same as the definition of "demand-side measures" set out in section 1 of the *Clean Energy Act*, which is "a rate, measure, action or program undertaken; (a) to conserve energy or promote energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demand, but does not include (d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or (e) any rate, measure, action or program prescribed".

End Use: The final application or final use to which energy is applied. Recognition of the fact that electric energy is of no value to a user without first being transformed by a piece of equipment into a service of economic value. For example, office lighting is an end use, whereas electricity sold to the office tenant is of no value without the equipment (light fixtures, wiring, etc.) needed to convert the electricity into visible light. End use is often used interchangeably with energy service.

ENERGY STAR®: ENERGY STAR® is the mark of high-efficiency products in Canada that meet strict technical specifications for energy performance—tested and certified. These products save energy without compromising performance in any way. Typically, an ENERGY STAR® certified product is in the top 15 to 30 per cent of its class for energy performance.

Expected Savings: Estimate of gross energy savings based on customer initially reported savings, engineering review and site inspection. These estimates represent the unverified savings.

Free Riders: Free riders are program participants who would have taken the DSM action, even in the absence of the DSM program. They are a part of the reference case. These actions are not attributable to the program.

Gigawatt Hour (GWh): One billion watt-hours; one million kilowatt hours.

Gross Savings : The change in energy consumption and/or associated demand that results directly from program-related action taken by the participants in the demand side management program irrespective of why they participated.

Market Changes: Market Changes refers to the changes in the structure or operations of markets during the course of an energy efficiency program that indicate increased levels of adoption of energy-efficient products and practices by customers and/or increased levels of promotion and delivery by suppliers.

Market Transformation: Market Transformation refers to a permanent change in the structure or functioning of markets, including more energy-efficient behaviour among customers and higher market penetration of energy-efficient products, as a result of DSM programs that reduce barriers to energy efficiency. These market changes are likely to persist in the absence of continued program activity.

Net savings: The change in energy consumption and/or associated demand that is attributable to the utility DSM program. The change in consumption or associated demand may include the effects of free riders and spillover.

Net-to-gross ratio: A factor representing net demand side management program savings divided by gross program savings that is applied to gross program impacts to convert them into net program load impacts. The factor is made up of a variety of factors that create differences between gross and net savings, commonly including free riders and spillover. Other adjustments may include rebound, cross effects and measurement and verification results.

Peak Demand - Demand refers to the amount of electricity that is consumed at any instant in time, measured in multiples of watts. Peak demand savings are the reduction in amount of electricity that is consumed at system peak demand, which for BC Hydro occurs on a winter weekday between approximately 5 p.m. and 7 p.m.

Persistence: Refers to how long the energy savings are expected to be attributable to the demand side management activity.

Realization Rate: The ratio of initial estimates of savings to savings adjusted for data errors and measurement and verification results. Does not reflect program attribution or influence on the savings achieved.

Reported Savings: Estimate of energy savings being recorded in the program tracking database. Reported savings are based on best information available from technical review of the initial engineering estimate, post implementation review of documentation and/or inspection, or measurement and verification results, as well as, a forecast net-to-gross ratio applied.

Run Rate: Run rate is the rate at which the Conservation and Energy Management programs or projects are saving electricity at a given point in time. This is usually expressed as GWh/year at the end of the month or year being reported.

Spillover: Refers to program participants and non-participants whose energy savings measures occur through actions that are not part of a program, but which were influenced by the program (also called free drivers or tag-ons). Participant spillover is the additional energy savings that occur when a program participant independently installs energy efficiency measures or applies energy savings practices after having participated in the efficiency program, as a result of the program’s influence. Non-participant spillover refers to energy savings that occur when a program non-participant installs energy efficiency measures or applies energy savings practices as a result of a program’s influence. Spillover is expressed as a fraction of the increase of energy savings due to spillover to the gross energy savings of the program participant. Spillover may not be permanent and may not continue in the absence of continued program activity.

BC Hydro
Power smart

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix AA

Attachment 2

Demand Side Management Milestone Evaluation Summary Report Fiscal 2018

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January 15, 2019

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
2004/05 and 2005/06 Revenue Requirements Application
Commission Decision: Order No. G-96-04, October 29, 2004,
Directive 66 (page 197)

BC Hydro writes to submit its F2018 Demand Side Management Milestone Evaluation Summary Report (**the Report**), dated December 2018 and the final report for Evaluation of the Residential Inclining Block Rate: F2013-F2017 in compliance with Directive 66 (page 197) of the Commission Decision on BC Hydro's 2004/05 to 2005/06 Revenue Requirements Application, dated October 29, 2004. Directive 66 directs BC Hydro to file the executive summaries of its milestone evaluation reports and full final evaluation reports for all its Power Smart programs.

The Report summarizes the impact evaluations completed during F2018 for the following:

1. Residential General Service Lighting: F2012-F2017;
2. Low Income Program: F2011-F2016;
3. Power Smart Partner – Distribution Program: F2011-F2016;
4. Residential Inclining Block Rate: F2013-F2017; and
5. Residential Retail Program – Consumer Electronics and Appliance Rebate Offers: F2011 to Second Quarter F2015.

The findings from the attached final report for the Evaluation of the Residential Inclining Block Rate: F2013-F2017 show that structural savings in F2016 and F2017 were deemed to be small or zero. Accordingly, no new incremental savings are forecast for the Residential Inclining Block Rate in BC Hydro's Demand-Side Management Plan, and no further evaluations will be undertaken. BC Hydro is therefore filing the full report as the final evaluation for the Residential Inclining Block Rate in compliance with Directive 66.

For further information, please contact Geoff Higgins at 604-623-4121 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

st/ma

Enclosure (1)

Demand Side Management Milestone Evaluation Summary Report F2018

December 2018

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1 Introduction

This report summarizes the milestone evaluations of demand-side management (**DSM**) initiatives completed by BC Hydro in fiscal year 2018 (**F2018**). It is filed in compliance with Directive 66 of the British Columbia Utilities Commission (**BCUC**) decision on BC Hydro's F05/F06 Revenue Requirements Application (dated October 29, 2004), which "*directs BC Hydro to file the executive summaries of its milestone evaluation reports and full final evaluation reports of all its Power Smart programs*" (page 197).

BC Hydro evaluates its DSM initiatives to improve its estimates of realized DSM electricity savings and to improve their effectiveness and efficiency.

DSM evaluation activities are guided by the following six principles:

- Objectivity and Neutrality: Evaluations are to be objective and neutral.
- Professional Standards: Evaluation work is guided by industry standards and protocols.
- Qualified Practitioners: BC Hydro employs qualified staff and consultants to conduct evaluations.
- Appropriate Coverage: BC Hydro strives to achieve defined coverage levels for its evaluation of DSM initiatives.
- Business Integration: The evaluation function is integrated into BC Hydro's DSM business process of planning, implementation, reporting and evaluation.
- Coordination: BC Hydro evaluation work is coordinated with FortisBC and other DSM partners where feasible.

BC Hydro DSM evaluations are subject to an independent oversight process to ensure that they are neutral and unbiased, of sufficient quality for their intended purposes, and consistent with industry standards and protocols.

1.1 Completed Evaluations

Impact evaluations summarized in this report focused on the following:

- Residential General Service Lighting: F2012-F2017;
- Low Income Program: F2011-F2016;
- Power Smart Partner – Distribution Program: F2011-F2016;
- Residential Inclining Block Rate: F2013-F2017; and
- Residential Retail Program – Consumer Electronics and Appliance Rebate Offers: F2011 to Second Quarter F2015.

2 Residential General Service Lighting: F2012-F2017

2.1 Introduction

This market and impact evaluation examines changes in the market and in-home installation trends for residential lighting in British Columbia over the past six years. It also presents evaluated gross savings in the residential sector from the reduction in electricity usage of incandescent general service lamps (**GSL**) during a period of time that encompasses the introduction of energy efficiency regulations. Estimates of gross savings at industrial and commercial facilities are not included.

Phase 1 of British Columbia's GSL Regulation came into force on January 1, 2011. The GSL Regulation provided minimum energy performance standards for a range of medium base screw-type electric lamps, effectively banning 75 to 100 watt incandescent lamps. Phase 2 of the regulation came into force in January 2015 when national minimum energy performance standards for 40 to 60 watt general service lamps came into effect, which effectively banned 40 to 60 watt incandescent lamps.

BC Hydro includes gross electricity savings from the GSL Regulations in its reported and forecast DSM savings and in its load forecast after DSM.

2.2 Approach

Shown below are the evaluation objectives, research questions, data sources and methods.

Table 1 Evaluation Objectives and Research Questions

Objectives	Research Questions
1. Supply side analysis	a. What are shelf share trends by lamp type? b. What are price trends by lamp type? c. What is the level of retailer compliance with the regulation?
2. Demand side analysis	a. What are long-term trends in the types of lamps used in the home? b. How familiar are customers with various lighting products? c. How satisfied are customers with various lighting products? d. How many customers purchased and installed various lighting products? e. How many customers put various lighting products into storage?
3. Gross energy savings from conversion of incandescent la mps	a. How much conversion of 40, 60, 75 and 100 watt incandescent lamps to other lamp wattages occurred in the homes of BC Hydro customers between F2011 and F2017? b. What is the wattage of 40, 60, 75 and 100 watt replacement lamps? c. What are the gross energy savings associated with conversion of 40, 60, 75 and 100 watt lamps to other wattages? d. What are the reasons behind any variance between reported and evaluated gross savings?

Table 2 summarizes, for each of the evaluation objectives, the evaluation data and methods used.

Table 2 Evaluation Objectives, Data and Methods

Objectives	Data sources	Method
1. Supply side analysis	• Shelf space survey (n= approximately 40 stores per year for 7 years, from F2011 to F2017)	• Cross tabulations • Trend analysis
2. Demand side analysis	• Telephone surveys of residential customers for F2011, F2012 & F2013 (approximately 400 to 600 responses per survey) • Online surveys of residential customers for F2016 (888 responses) and F2017 (2,222 responses) • Residential End Use Surveys from F2002, F2004, F2007, F2009, F2011, F2013, F2015, F2017 (approximately 4,200 to 7,600 responses for the lighting section)	• Cross tabulations • Trend analysis
3. Gross energy savings from conversion of incandescent la mps	• F2011 residential monitoring study (48 homes audited) • F2014 residential audits (56 homes audited) • F2017 residential audits (233 homes audited) • Residential End Use Surveys from F2011, F2013, F2015 and F2017 • BC Hydro Annual Reports for F2011 to F2017 • BC Hydro Codes and Standards savings forecast as of spring 2017	• Engineering algorithms

Objective 1, related to supply side analysis, was completed using shelf space data. The lighting shelf space studies cover approximately 40 retail stores annually and collect a range of information on a census count of specific lighting products on the shelves of each store.

Objective 2, related to demand side analysis, was completed through cross tabulations and trends analysis of data from surveys of BC Hydro's customers. Lighting surveys collected data on consumer awareness of various lighting technologies, purchase and installation rates, satisfaction and other measures. Residential End Use Surveys collected detailed information about lighting products installed in the home.

Objective 3, related to gross savings, was completed using engineering algorithms with inputs from monitoring studies or home audits, Residential End Use Surveys and BC Hydro annual reports. The analysis involved seven steps: 1) estimate the total number of incandescent lamps installed in homes in each year of interest, 2) determine the distribution of incandescent lamp wattages installed in homes, 3) estimate the average number of incandescent lamps per home by wattage, 4) calculate the power draw of GSL replacement lamps, 5) identify hours of use and peak coincidence, 6) adjust for cross effects, and 7) calculate evaluated gross savings.

2.3 Results

Objective 1: Supply Side Analysis

The shelf space occupied by incandescent lamps dropped from 51 per cent in F2012 to 24 per cent in F2017. During this same period, shelf space occupied by LED lamps rose from 4 per cent to 40 per cent, taking over the largest share of shelf space in F2016. While compact fluorescent lamps (**CFLs**) had a fairly consistent shelf space share of about 25 per cent from F2012 to F2014, their share has steadily declined since then and reached 13 per cent in F2017. Halogen lamps have held fairly consistent shelf space since F2013, fluctuating between 17 per cent and 21 per cent.

Incandescent (60 watt A-shape) lamp prices have increased from an average of $0.85 in F2011 to $1.43 in F2017, while LED (A-shape) lamp prices have declined from an average of $24.63 in F2011 to $8.97 in F2017. Prices for CFL (13 watt spiral) lamps were generally stable, while prices for halogen (A-shape) lamps fluctuated somewhat through the period.

Within incandescent shelf space, up to 28 per cent was stocked with potentially non-compliant lamps in F2017. Compliance with the GSL regulations may be higher than indicated by this figure because the shelf space study did not record all lamp features that would have exempted lamps from the regulations.

Satisfaction ratings were collected only for CFL and LED lamps and in select years only. Satisfaction with CFL lamps in F2011 (regular and specialty lamps combined), was high at 89 per cent. In F2012 and F2013, results were available for specialty CFLs only and satisfaction was somewhat lower at 79 per cent in F2012 and 72 per cent in F2013. Satisfaction with LED lamps was high at 85 per cent in F2012 and increased to 93 per cent in F2013.

Objective 2: Demand Side Analysis

- During the evaluation period, the average total number of lamps installed per home was fairly flat at approximately 38 until F2017 when the number increased to 39.8. Incandescent lamps decreased from 17.6 lamps in F2011 to 13.1 lamps in F2017. CFLs reached their peak in F2013 at an average of 9.9 lamps, but have since decreased to 8.1 lamps in F2017. Halogen lamps fluctuated somewhat over the period, increasing in the early years from a low of 5.1 in F2011 to a high of 6.1 in F2015, but decreased to 5.4 lamps in F2017. LEDs increased rapidly from an average of less than one lamp per home in F2011 to 8.8 lamps in F2017. Fluorescent tubes were relatively stable throughout the evaluation period at approximately three tubes per home, while other lamps decreased slightly from 2.5 to 1.6.
- Based on the F2016 BC Hydro Lighting Survey, awareness of all lamp types is high, with 92 per cent of customers aware of halogens, 93 per cent aware of LEDs, 96 per cent aware of CFLs and 98 per cent aware of incandescents. In terms of

purchases over the past year, the share of customers that purchased at least one incandescent lamp has been steadily declining in recent years (from 44 per cent in F2012 to 34 per cent in F2016), as has the average number purchased (from 11.0 in F2012 to 6.8 in F2016). In contrast, the share that purchased at least one LED lamp has been steadily increasing (from 7 per cent in F2011 to 35 per cent in F2016), as has the average number purchased (from 3.7 in F2011 to 8.3 in F2016). Although the percentage of customers reporting that they had at least one incandescent lamp in storage has remained relatively flat in recent years (between 58 per cent and 65 per cent), the average number of reported lamps in storage has decreased from 10.0 in F2012 to 6.8 in F2017. This translates into approximately 7.1 million incandescent lamps in storage across BC Hydro's service territory.

Objective 3: Evaluated Gross Energy Savings

During the evaluation period, the average number of incandescent lamps installed in homes decreased from 17.6 in F2011 to 13.1 in F2017. Since the introduction of the Phase 1 regulation, the average number of 75 to 100 watt lamps per home decreased from 2.8 to 1.1, with decreases in all wattage categories covered by the regulation. Looking at the pre- to post-regulation period for Phase 2 lamps (F2014 to F2017), there was an overall decrease from 12.1 to 11.0 regulated lamps installed in the home, but decreases were not seen across all wattage categories. Decreases were only observed for lamps in the 40 to <60 watt range, but increases were observed for lamps in the 60 to <75 watt range, which were also covered by the regulation.

The power draw of replacement lamps was estimated at 12.8 watts, based on a weighted average of CFL and LED wattages installed in the home in F2017.

Evaluated gross electric energy savings in residential homes from the changes in incandescent general service lighting were 251 GWh per year in F2017, or 37 per cent of reported savings. This was made up of 226 GWh per year among lamps affected by Phase 1 of the regulation and 25 GWh per year among lamps affected by Phase 2 of the regulation. Energy savings are expressed as an annual rate of savings in F2017 due to changes since the identified baseline year (F2011 in the case of Phase 1 and F2014 in the case of Phase 2).

Table 3 Reported vs Evaluated Savings in F2017

		Energy Savings (GWh/year)		Peak Demand Savings (MW)
		Reported	Evaluated Gross	Evaluated Gross
F2017	Phase 1 lamps	300	226	75
	Phase 2 lamps	377	25	8
	Total	**677**	**251**	**83**

One of the main reasons for the variance between reported and evaluated savings, particularly for Phase 1 lamps, is a difference in assumptions used to estimate the number of regulated lamps in each of the wattage categories in F2011. Because the home audit data was not available when the reported savings model was first developed, it used shelf-space data to estimate the distribution of incandescent wattages, while this evaluation used the distribution of incandescent wattages based on home audits. The shelf-space method overestimated the relative share of 100 watt lamps and underestimated the relative share of 40 watt lamps as compared to the audit data.

The other main reason for the variance is that this evaluation found that the rate of replacement of incandescent lamps has been slower than assumed in reported savings, particularly for Phase 2 lamps. Reported savings assumed that by F2017, there would be a reduction of 15.8 million regulated lamps (approximately 5.1 million Phase 1 lamps and 10.7 million Phase 2 lamps, based on the wattage distributions from the shelf-space study). In contrast, this evaluation estimated that the reduction was in the range of 5 million lamps (approximately 3.1 million Phase 1 lamps and 1.9 million Phase 2 lamps, based on the wattage distributions from the home audits). This suggests that there are still a significant number of incandescent lamps to be replaced, and as the trend towards more efficient lighting continues, there are still significant savings to come in future years.

2.4 Findings and Recommendations

Findings

1. The shelf space of incandescent lamps has halved since F2012 (from 51 per cent to 24 per cent of total lighting shelf space), while the shelf space of LEDs has rapidly increased (from 4 per cent to 40 per cent), indicating that a shift towards energy efficient lighting has occurred in the market at the retail level.
2. The price of LEDs has been sharply declining in recent years, while the price for incandescents has been gradually increasing.
3. Within incandescent shelf space, the percentage that was stocked with potentially non-compliant lamps was estimated at a maximum of 28 per cent in F2017.
4. The number of incandescent lamps installed in the home has been decreasing steadily, while LEDs have been increasing rapidly. CFLs installed in the home appear to have peaked around F2013.
5. Although incandescent lamp purchases have declined over time, there are still a significant number of household purchasing them. In F2016, 34 per cent of households purchased at least one and among those that did, they purchased an average of 6.8 lamps.
6. Customers still have a high number of incandescent lamps in storage – an estimated 7.1 million across BC Hydro’s service territory.
7. The average number of incandescent lamps installed in the home decreased from 17.6 to 13.1 between F2011 and F2017. As of F2017, there were an average of only 1.1 Phase 1 lamps remaining in the home, but still an average of 11.0 Phase 2 lamps.
8. Evaluated gross electric energy savings in residential homes from changes in general service lighting were 251 GWh/year in F2017, which was 37 per cent of reported savings.
9. The main sources of difference between reported and evaluated savings were assumptions about the baseline number of incandescent lamps by wattage

category and the rate of replacement of incandescent lamps. The home audit data was considered to be a better representation of installed incandescent wattages in the home compared to the shelf space data.

Recommendations

1. Consider collecting additional information on lamp characteristics in the shelf space studies in order to better estimate compliance. Consider encouraging government to increase enforcement efforts on regulated lamps if compliance is found to be low.
2. Evaluation and Codes & Standards staff should periodically share information with each other on available data that can inform estimates of reported and forecast savings.

2.5 Conclusions

There have been significant changes in the market for general service lamps between F2011 and F2017, with shifts occurring from incandescent to LED lamps, both on store shelves and installed in homes. However, the rate of replacement for incandescent lamps has been slower than anticipated and there remain a considerable number of 40 to 60 watt incandescent lamps still to be replaced. Evaluated gross savings are 37 per cent of reported.

3 Low Income Program: F2011-F2016

3.1 Introduction

The evaluation encompasses two Low Income Program offers over two separate time periods: Energy Saving Kits for the period April 2010 through March 2016 (ESK: F2011-F2016) and the Energy Conservation Assistance Program – Basic Offer for the period April 2011 through March 2016 Energy Conservation Assistance Program (**ECAP**) Basic: F2012-F2016).

The Low Income Program is a BC Hydro energy acquisition initiative to help income qualifying residential customers reduce their energy bills. During the evaluation period the program provided BC Hydro income qualifying residential customers with free energy efficient products and contractor-installed energy efficiency upgrades.

The program's key objectives were to:

- Make energy efficiency more accessible to low income customers by addressing the key barriers to energy efficiency in this sector (e.g., affordability, availability and awareness).
- Provide energy savings to BC Hydro through the installation of energy efficiency measures.
- Provide low-income customers with the opportunity to reduce their energy consumption and utility bills through energy efficiency improvements.
- Increase knowledge about energy conservation among low-income customers.

The Low Income Program launched in 2008 and has operated continuously since that time.

The scope of this evaluation includes the program's two largest offers: the Energy Saving Kit (**ESK**) and ECAP Basic. Two small offers were not evaluated: the Advanced Weatherization offer and the Apartment Direct Install offer. They accounted for 2 per cent and 1.5 per cent of the program's reported electricity savings, respectively, over the evaluation period. They were not included in this evaluation for method reasons.[1]

The program was available to income qualifying residential customers. Statistics Canada's Low Income Cut Off (**LICO**) was used as the income qualification level prior to July 2014. On July 10, 2014 the income qualification level was raised to 1.3 times the LICO, and recipients of various government income and housing assistance programs were pre-qualified.[2]

The ESK is a package of basic, low-cost energy saving measures that can be installed by a homeowner or tenant. ESKs included items such as energy-efficient light bulbs, faucet aerators, window film and a refrigerator thermometer. Installation of the kit contents resulted in energy savings in lighting, space heating, and water heating.

The ECAP Basic offer was available to income qualified residential customers who lived in single family dwellings, duplexes, townhouses or mobile homes.[3] Eligible applicants received a basic home energy audit, installation of energy saving products, and education on energy saving actions from a contractor. The specific installations varied depending on the outcome of the basic audit, and included products to save on lighting, space heating and water heating. Some customers were also eligible for a refrigerator replacement.

3.2 Approach

Shown below are the evaluation objectives, research questions, data sources and methods.

[1] Participation in Advanced Weatherization was too low to enable statistical analysis. Electricity consumption data was not available for a number of Apartment Direct Install participants.
[2] BC Hydro 2015 Rate Design Application, Chapter 5.
[3] Prior to December 2013 eligibility was also based on annual energy consumption.

Table 4 Evaluation Objectives and Research Questions

Objectives	Research Questions
1. Understand the program's target market and barriers to energy efficiency	• What are the characteristics of the population of eligible program participants? • What are the barriers to energy efficiency improvements among low income customers? • How are program participants different from the general population?
2. Assess the participant experience and measures installed through the ESK offer	• What was the installation rate by kit component? • How easy were the kit contents to install? • How satisfied were participants with the ESK offer? • Would participants have purchased most of these products on their own? • Would participants recommend the ESK to someone they know?
3. Assess the participant experience and measures installed through the ECAP Basic offer	• What measures were installed through the ECAP Basic offer? • How did participants learn about the ECAP Basic offer? • Did participants take additional energy savings actions as a result of participation in the ECAP Basic offer? • How satisfied were participants with the measures installed through ECAP Basic?
4. Estimate net electric energy and demand savings for the ESK and ECAP Basic offers	• What are the net electricity savings attributable to ESK by fiscal year? • What are the net electricity savings attributable to ECAP Basic by fiscal year?
5. Assess the effect of program participation on electricity bill payment performance	• How does participation in the Low Income Program impact the bill payment performance of participating homes?

Table 5 summarizes, for each of the evaluation objectives, the evaluation data and methods used.

Table 5 Evaluation Objectives, Data Sources and Methods

Objectives	Data sources	Method
1. Understand the program's target market and barriers to energy efficiency	• 2012, 2014 Residential End Use Survey • Statistics Canada • Literature review • BC Hydro 2015 Rate Design Application	• Qualitative research
2. Assess the participant experience and measures installed through the ESK offer	• 2014-2015 ESK Apartment Participant Survey (N=460) • 2014-2015 ESK House Participant Survey (N=544)	• Cross tabulations
3. Assess the participant experience and measures installed through the ECAP Basic offer	• 2014-2015 ECAP Participant Survey (N=722)	• Cross tabulations
4. Estimate net electric energy and demand savings for the ESK and ECAP Basic offers	• Electricity consumption data • BC Hydro account data • Program tracking data • Weather data	• Quasi-experimental design with variation in adoption • ANCOVA fixed effects modelling
5. Assess the effect of program participation on electricity bill payment performance	• Program tracking data • Creditworthiness score data • Electricity consumption data	• Quasi-experimental design • ANCOVA fixed effects modelling

The first objective, related to better understanding the program's target market and barriers to participation, was addressed through a review of Statistics Canada information and data collected through BC Hydro's Residential End-Use Surveys.

The second and third objectives, related to assessing the participant experience and measures installed through ESK and ECAP Basic, were addressed using the results of BC Hydro's ESK Apartment, ESK House and ECAP Participant Surveys. The surveys were optional and mailed in to BC Hydro by the program participants throughout most of 2014 and 2015.

The fourth objective, related to net savings, was addressed by conducting statistical analysis separately for ESK and ECAP Basic using electricity consumption and other data. The analysis involved quasi-experimental design with variation in adoption and

ANCOVA fixed effects modelling. This evaluation method produced a reliable estimate of average net savings per participant by fiscal year for both ESK and ECAP Basic.

The fifth objective, related to assessing the effect of program participation on electricity bill payment performance, was also addressed by conducting statistical analysis on creditworthiness scores. The analysis involved the same techniques as objective four.

The method for estimating net electric energy savings was used to provide some insights into savings persistence, the average daily shape of savings and savings seasonality. Peak demand savings were calculated using the evaluated savings shape.

3.3 Results

Objective 1: Understand the Program's Target Market and Barriers to Energy Efficiency

The prevalence of low income families in British Columbia has been higher than in Canada as a whole for more than a decade. The 2016 Census indicated that low income individuals make up 14.4 per cent of the population in British Columbia compared to the national average of 12.8 per cent.[4] The low income population is commonly made up of single parent families and persons not living in an economic family,[5] both elderly and non-elderly. Indigenous people, recent immigrants and persons living with a disability are also at higher risk of being low income compared to the rest of the population.

Members of these vulnerable groups face considerable challenges and barriers. Statistics Canada's LICO outlines the total household income required to qualify as low income, based on the number of occupants in the home. The LICO threshold captures both the very poor and the working poor. Approximately 70 per cent of Canadians living

4 Statistics Canada, 2016 Census of Population, Statistics Canada Catalogue no. 98-400-X2016124. Accessed November 17, 2017.
5 An economic family refers to a group of two or more persons who live in the same dwelling and are related to each other by blood, marriage, common-law, adoption, or a foster relationship.

in poverty (3.1 per cent of all Canadian families) are considered to be working poor.[6] The working poor typically have precarious employment situations (e.g., contract, part-time or temporary work); make minimum wage; have limited or no benefits; and have multiple jobs to cover basic living costs. They have no liquid assets or savings to draw upon, and may be dealing with inadequate housing conditions and food insecurity issues. These challenges can lead to the following barriers to low income households participating in energy efficiency improvements: 1) initial financial outlay required to purchase the measures, 2) duration of customer pay-back from bill saving due to energy efficiency measures, 3) high proportion of renters and, 4) tendency for higher household mobility among renters.

BC Hydro estimates that approximately 11 per cent of residential customers have household incomes below the LICO threshold. With the expansion of program eligibility in 2014 to 1.3 times the LICO, an estimated 21 per cent of residential customers became eligible for the program. From 2014 on, the expansion of the income qualification criteria contributed to a 23 per cent increase in program participation, implying that program participants after that date had higher average income levels than the general population of low-income customers, defined as below LICO.[7]

The energy consumption of ESK, ECAP Basic and all BC Hydro customers was also analysed and compared. The results showed that of the three groups, ECAP Basic participants spend the largest percentage of their income on electricity (4 to 10 per cent) as compared to ESK (2 to 8 per cent) and all customers (2.5 per cent or less) and have the highest electricity consumption per square foot.

6 Lefroncois, A. Canada's Working Poor and Precarious Employment. November 2015. Accessed October 18, 2017, http://www.livingwagecanada.ca/index.php/blog/canadas-working-poor-and-precarious-employment/.
7 BC Hydro 2015 Rate Design Application, Chapter 5, pages 5-76 and 5-77.

Objective 2: Assess the Participant Experience and Measures Installed through the ESK Offer

As noted above, data for this objective was collected through separate surveys of participants living in apartments and houses. However, there was minimal variation in survey responses by dwelling type so the results were combined.

The majority of respondents agreed or strongly agreed that the products were easy to install, that they were satisfied with the products received, and that they would recommend the kits to someone they know. On the five-point agreement scale, where one is "*strongly disagree*" and five is "*strongly agree*". Respondents averaged a score of 2.5 when asked whether they would have purchased most of the products on their own.

Reported installation rates were similar between apartments and houses. The highest installation rate was found for the LED night light and the fridge/freezer thermometer, at approximately 94 per cent. This was followed by the kitchen tap aerator (79 per cent) and CFL light bulbs (76 per cent). Between 41 to 45 per cent of participants living in apartments and houses did not install any window insulator film.[8]

Objective 3: Assess the Participant Experience and Measures Installed through the ECAP Basic Offer

Approximately 50 per cent of respondents learned about ECAP Basic through mail or bill inserts. Others learned about the program through avenues such as their property manager, online, through a friend or family member or from an ECAP representative. There was a mixed response when asked whether their household would have purchased and installed products on their own. Approximately 30 per cent agreed, 25 per cent neither agreed nor disagreed and 40 per cent disagreed. Around 80 per cent of respondents indicated that they had implemented additional energy savings actions since participating in ECAP Basic and the majority of respondents agreed or strongly agreed that they were satisfied with the products installed.

[8] During the program application process, participants could opt in to receive window film or not. This install rate includes participants that requested window film and did not install it, as well as those who requested no window film at all.

A review of program tracking data showed that the most commonly installed product categories were refrigerator thermometers and lighting products, which were installed by 96 per cent and 85 per cent of participating households, respectively. Between 40 to 60 per cent of participating households installed some type of draft-proofing or water heating measure, low flow shower heads, or carbon monoxide (**CO**) detectors. Refrigerators were replaced in about 21 per cent of participating households.

The average number of measures installed per home through ECAP Basic increased in F2013, most notably for lighting products, low flow faucets and CO detectors. The average number of measures installed per home remained relatively stable in subsequent years.

Objective 4: Net Electricity Savings for ESK and ECAP Basic

The evaluated and reported net savings by fiscal year are shown below. Evaluated savings are incremental annual savings.

Table 6 Summary of ESK and ECAP Basic Net Savings F2011-F2016

	Fiscal Year	Energy Savings (GWh/year)		Peak Demand Savings (MW)	
		Reported	Evaluated Net	Reported	Evaluated Net
ESK & ECAP Basic	F2011 (ESK only)	4.7	5.3	1.0	1.1
	F2012	5.9	5.2	1.2	1.0
	F2013	3.3	4.5	0.7	0.9
	F2014	3.5	4.2	0.7	0.8
	F2015	3.1	3.6	0.6	0.7
	F2016	2.8	4.3	0.6	0.9
Total		**23.3**	**27.0**	**4.8**	**5.5**

The results for F2011 include net savings for ESK only. F2011 savings for ECAP Basic were covered in a previous evaluation.[9]

Evaluated savings from both ESK and ECAP Basic were greater than reported savings. ESK evaluated savings totaled 19.7 GWh per year or 116 per cent of reported savings

9 BC Hydro, 2012.

of 17.0 GWh per year. ECAP Basic evaluated savings totaled 7.3 GWh per year or 116 per cent of reported savings of 6.3 GWh per year. The variance is largely due to the evaluation finding that unit savings were higher than anticipated in most years of the evaluation timeframe.

As noted in the introduction, electricity savings from the program's Advanced Weatherization and Apartment Direct Install offers were not included in the scope of this evaluation and are therefore not included in the evaluated savings.

Objective 5: Assess the Effect of Program Participation on Electricity Bill Payment Performance

Statistical analysis on a subset of program participants (those who installed both an ESK and participated in ECAP Basic) revealed improvements in electricity bill payment performance among those who had a history of late payment prior to participating in the program. On average, the creditworthiness scores of F2013 ECAP Basic program participants who previously installed an ESK and who had at least some late payments in F2012 declined (improved) by 56 per cent in F2014. This means that for these participants, the program had a statistically significant influence on their ability or willingness to pay their bills in full and on time. This evaluation did not examine whether a similar outcome would be achieved by customers who participated in other offers or initiatives (e.g., ESK only), or by customers with different demographic or other characteristics than those who were analyzed.

3.4 Findings and Recommendations

Findings

Below are the evaluation findings.

1. The prevalence of low income households is higher in BC than the rest of Canada, and is slightly higher in the Lower Mainland than the rest of BC.
2. Barriers to low income customers participating in energy efficiency improvements include the cost of energy saving products or measures, a rental situation denying

them authority or incentive to invest in energy efficiency and a higher level of household mobility.

3. The large majority of 2014 and 2015 participants found the ESK products easy to install, were satisfied with the products and would recommend the ESK to someone they knew.
4. The large majority of 2014 and 2015 ECAP participants were satisfied with the products installed and have taken additional steps to save energy since the measures were installed.
5. Between F2011-F2016, 70,475 homes registered for an ESK.
6. On average, between F2011 and F2016, ESK participants saved between 262 and 316 kWh per year per home with each kit installed. These averages apply across all regions, building types, and space and water heating fuels.
7. Analysis of F2011 ESK participants living in owned, single family dwellings in the Lower Mainland found that ESK measures saved 752 kWh per year in electric space heating, 496 kWh per year in electric water heating and 159 kWh per year in other end-uses.
8. ESK evaluated net savings between F2011 and F2016 were 19.7 GWh per year, which equates to 116 per cent of what was reported.
9. Between F2012-F2016, 9,358 homes were verified as having installed measures through ECAP Basic.
10. On average, between F2012 and F2016, ECAP Basic participants saved between 642 and 899 kWh per year per home. These averages apply across all regions, building types, and space and water heating fuels.
11. ECAP Basic evaluated net savings between F2012 and F2016 were 7.3 GWh per year, which equates to 116 per cent of what was reported.

12. The evaluated net savings for both ESK and ECAP Basic over the evaluation period was 27.0 GWh per year, which equates to 116 per cent of what was reported.
13. The average ESK unit savings in multi-unit buildings serviced by a single BC Hydro meter could not be estimated due to insufficient data.
14. Among ECAP Basic program participants in F2013 who had at least one late electricity bill payment prior to participating in the program, there was an average 56 per cent reduction (improvement) in their BC Hydro creditworthiness scores between F2012 and F2014. This indicates that among those who participated in both ESK and ECAP Basic, the program had a statistically significant influence on the ability or willingness to pay their bills on time and in full.
15. BC Hydro does not systematically archive creditworthiness score data for residential customers and this limits the ability to analyze the program's impact on bill payment performance.
16. The evaluation required extensive time to clean the program tracking data and understand the impact of program changes on the data over time which could be reduced through changes to data management practices.

Recommendations

Below are the evaluation recommendations. Recommendations 1 through 5 are for program management. Recommendation 6 is for evaluation.

1. Consider continuing to deliver periodic customer surveys if there is an interest in understanding changes in customer satisfaction and measure installation rates over time.
2. In the case of multi-unit residential building where all units share one BC Hydro account and only a portion of residents participate in the program, consider collecting information on all units in the building to increase the feasibility of evaluating this group in the future.

3. Consider systematic archiving of selected creditworthiness score data in order to support future analysis of the program's impact on the bill payment performance of income qualifying residential customers.
4. Continue to seek out opportunities to improve data quality. Actions may include, removing unused data fields in the program tracking data, creating a drop down menu for applicable information fields, developing a data dictionary and reviewing the process for crosschecking customer account ID's against the BC Hydro billing system.
5. Document relevant program changes over time in order to facilitate future evaluations.
6. Determine whether there is a need or interest in further delineation of program savings (e.g., by space or water heating fuel or by building type) to inform evaluation planning going forward.

3.5 Conclusions

The majority of Low Income Program participants were satisfied with the measures installed through the program.

The Low Income Program was successful in achieving electric energy savings among BC Hydro's low income customers. Evaluated net savings were 27.0 GWh per year by the end of F2016, which was 116 per cent of what was reported.

There is evidence to suggest that participation in both ESK and ECAP Basic influenced the electricity bill payment performance of income qualifying customers who had a history of late electricity bill payment prior to participating.

4 Power Smart Partner – Distribution Program: F2011-F2016

4.1 Introduction

This is an impact evaluation of BC Hydro's Power Smart Partner – Distribution (**PSP-D**) DSM program for BC Hydro fiscal years F2011 to F2016 (April 2010 to March 2016). This evaluation also includes elements of a process and market evaluation for the period F2011 to F2016.

BC Hydro's PSP-D program (renamed Leaders in Energy Management – Distribution in F2016) is a multi-year energy acquisition and market transformation initiative that encourages industrial customers that receive electricity supply at distribution voltage to reduce their electricity consumption. The program's target market is BC Hydro's industrial customer sites that are serviced at distribution voltage (< 69 kV). The key program objective during the period evaluated was to partner with program participants to obtain cost-effective electricity savings from capital projects by encouraging them to integrate energy efficiency into their on-going business practices and supporting the development and implementation of energy management systems.

The scope of this evaluation includes electrical energy efficiency and conservation projects at industrial distribution sites, including retrofit and new plant design and plant expansion projects, but excluding operational and procedural measures not supported by a formal sustainment plan. This encompasses the incentive offer and enabling activities, as further described below. During the six-year evaluation timeframe, 2,215 energy efficiency and conservation projects were completed at 767 participating customer sites and reported under the program. Program participants included the following industrial segments: wood, manufacturing, food and beverage, transportation and oil and gas. Similarly, the program reported projects in various end uses with a primary focus in lighting, compressed air and industrial processes.

The main program components and enabling activities in PSP-D F2011-F2016 are summarized below:

- **Custom Projects**
  - Incentives**:** Incentives of up to 75 per cent of project costs were available for custom projects.
  - Program Enabled**:** Customer-funded projects that did not receive direct capital incentive funding but were reported as a result of other program enabling activities.
- **Prescriptive incentives**: Since F2014, smaller lighting and compressed air projects were also eligible for prescriptive incentives under the self-serve incentive program (**SIP**). The Product Incentive Program (**PIP**) and Power Smart Express (**PSX**) were prescriptive programs for customers that consume less than 0.5 GWh per year and offered incentives for simple, one-for-one lighting retrofits.
- **BC Hydro Key Account Managers:** Acted as a liaison between the program and the customer.
- **BC Hydro Alliance of Energy Services Professional (formerly known as the Power Smart Alliance):** Trained and pre-qualified trade allies offering energy efficiency products and services to BC Hydro customers.
- **Energy Studies:** To identify and support a business case for implementation of energy conservation measures. Partially or fully funded by BC Hydro.
- **Energy Managers:** Helped participants adopt strategic energy management practices. Partially funded by BC Hydro.

4.2 Approach

The evaluation objectives and research questions are shown below, followed by the data sources and methods.

Table 7 Evaluation Objectives and Research Questions

Evaluation Objective	Research Questions
1. Assess participant and non-participant experience and satisfaction	What is the participant and non-participant experience related to awareness, understanding, and satisfaction with the various program offers (custom incentive, program enabled, new plant design, prescriptive incentive)? What are the barriers to and drivers of program participation?
2. Assess the program enabling activities	What proportion of the savings came from sites with a BC Hydro funded Energy Manager over time? What is the relationship between presence of energy managers and project activity? Which of the enabling activities had the greatest association with project activity, in general and over time? What could be done to improve the evaluability of the program enabling activities?
3. Estimate gross electrical energy and peak demand savings	What were the gross realization rates by end use? What were the evaluated gross energy and demand savings realized by the PSP-D program, delineated by fiscal year and by offer to the extent possible?
4. Estimate net electrical energy and peak demand savings	What are the evaluated net energy savings and demand savings realized by the PSP-D program, delineated by fiscal year and by offer to the extent possible? What factors impact free ridership among custom and prescriptive projects? How much free ridership occurred among custom and prescriptive projects? How much participant and non-participant spillover occurred in response to the program offers?

Table 8 Evaluation Objectives, Data and Methods

Evaluation Objectives	Data	Method
1. Assess participant and non-participant experience and satisfaction	• 6 waves of participant surveys covering F2011 to F2016 (n=328) • 2 waves of non-participant surveys covering F2011 to F2015 (n=206)	• Cross tabulations
2. Assess the program enabling activities	• Program tracking data	• Cross tabulations • Qualitative analysis
3. Estimate gross electrical energy and peak demand savings	• Program tracking data • Project files • Measurement and Verification results (n=297 measures) • Evaluation Review results (n=20 measures)	• Engineering calculation for measure evaluation review • Extrapolation of Measurement and Verification and Evaluation Review results using stratified ratio estimation • Rate class average peak-to-energy factor
4. Estimate net electrical energy and peak demand savings	• Results of Objective 3 • Project files • Participant survey (n=328 responses covering 341 projects) • Non-participant survey (n=206) • Case studies (n=40 projects)	• Triangulation of case study and survey based free ridership estimates • Survey based spillover algorithm • Rate class average peak-to-energy factor

4.3 Results

Objective 1: Participant and Non-Participant Experience and Satisfaction

Awareness of BC Hydro's conservation programs for industrial customers was highest among custom participants (87 per cent) and non-participants (84 per cent), as well as among SIP participants with a Key Account Manager (**KAM**) (85 per cent). Awareness was somewhat lower for SIP participants without a KAM (78 per cent), SIP non-participants (77 per cent) and Product Incentive Program or Power Smart Express (PIP/PSX) participants (79 per cent), and much lower for PIP/PSX non-participants (52 per cent). In terms of individual program components, understanding and overall ratings were highest for the role that KAMs play as liaisons of the program and the incentive structures for the SIP and custom offers.

Overall satisfaction with the custom and SIP offers was very high with 94 per cent of custom participants, 93 per cent of SIP participants with a KAM, and 91 per cent of SIP participants without a KAM rating it as excellent or good. Satisfaction was somewhat lower for PIP/PSX participants at 83 per cent. In terms of program experience, service provided by contractors and suppliers/distributors rated highly among all participant groups, as did service provided by BC Hydro personnel among those customers with a KAM. Areas which rated lowest included direct mail/email about the program (for all offers), length of time to receive project approval (for the custom incentive offer), length of time to receive incentive (for the custom incentive offer), information about the program on the website (for the SIP offer), variety of products funded by the program (for SIP and PIP/PSX) and usability of the online application (for PIP/PSX).

Among all participant and non-participant groups, the factors that emerged as the greatest motivators to conserve electricity were making operating costs as low as possible, the overall level of electricity prices, a focus on cost cutting measures due to the economic downturn or conditions, and to benefit the environment. Among participants, the individual program offers also emerged as motivators. The largest barriers to conserving electricity were lack of funds for energy efficient retrofits, other operational priorities, and a lack of financial incentives for conservation programs. Among non-participants, the main reasons for not participating in the PSP-D program were that the benefits were not worth it, the customer needed more information, and the customer thought the organization was not eligible to participate.

Objective 2: Assess the program enabling activities

Program enabling activities provided participants with a suite of tools and offers intended to help them to implement energy saving projects while also building energy management activities into their standard business practices over the long term. The tools and offers included funding for an energy manager position, energy efficiency feasibility studies, customer site investigations and plant-wide audits, end use assessments, as well as the support and expert consultation from the BC Hydro Alliance.

The evidence reviewed for this evaluation indicates that energy managers played an important role in program participation. During the evaluation period, sites with energy managers completed more than twice as many projects per site relative to those without energy managers (on average, 2.7 projects versus 1.2 projects). Also, the relative level of project savings (as a per cent of site energy consumption) was twice as high at sites with energy managers than at sites without an energy manager for small and large sites based on site energy consumption during the evaluation period.

Under the program's custom offer, 25 per cent of the projects implemented during the evaluation period, and 43 per cent of the expected energy savings, were supported by a program-funded energy study. Similarly, 34 per cent of the projects and 43 per cent of the expected energy savings were supported by a program-funded energy manager. Further, 72 per cent of expected energy savings were supported by either an energy study or an energy manager, indicating that most sites participated in either the energy manager or energy study program enabling activity but not both. Sixty per cent of energy savings occurred at sites that had previously participated in one of the program's enabling activities.

Objective 3: Estimate gross electrical energy and peak demand savings

Evaluated gross energy savings provide an estimate of savings achieved at participating sites, irrespective of whether they are attributable to the program. Evaluated gross savings are estimated by applying a realization rate derived from measurement and verification results to the expected savings by end use measure. The three samples of end use measures that were evaluated were lighting, compressed air and other end uses with realization rates and evaluated gross energy savings of 101 per cent (122 GWh/year), 112 per cent (43 GWh/year), and 89 per cent (55 GWh/year) respectively. An overall realization rate of 99 per cent was calculated for the entire program in the evaluation period, indicating that, on average, projects supported by the program achieved their expected savings. Evaluated gross energy savings averaged 8.5 per cent of site energy consumption across all participants during the six year evaluation period.

Table 9 Summary of Gross Energy and Peak Demand Savings

Period	Number of Measures	Energy Savings (GWh/year)		Peak Demand Savings (MW)
		Expected Gross	Evaluated Gross	Evaluated Gross
F2011	579	43.7	44.2	6.0
F2012	806	34.4	36.4	4.9
F2013	733	40.1	38.1	5.2
F2014	521	27.5	27.1	3.7
F2015	534	44.7	43.5	5.9
F2016	550	30.9	30.6	4.2

Objective 4: Estimation of Net Electricity Savings

Net electricity savings are the change in energy consumption and demand that is attributable to the program. They exclude free riders and include spillover. Free ridership provides an estimate of the proportion of evaluated gross energy savings that are not attributable to the program. Free ridership was estimated separately for the three types of projects reported by the program: custom, SIP and PIP/PSX with estimated free ridership of 14 per cent, 12 per cent and 18 per cent respectively. Spillover savings are additional savings that occurred due to the program's influence. Spillover was estimated at 11 per cent for the overall evaluation period among participants and non-participants. An overall net to gross ratio of 97 per cent was calculated for the entire program in the evaluation period. Evaluated net energy and peak demand savings are shown in Table 10 and average 108 per cent of reported savings, showing that the program performed better than reported.

Table 10 Summary of Net Energy and Peak Demand Savings

	Energy Savings (GWh/year)		Peak Demand Savings (MW)	
Period	Reported	Evaluated Net	Reported	Evaluated Net
F2011	41.9	43.1	5.7	5.9
F2012	31.2	35.3	4.2	4.8
F2013	35.9	36.8	4.9	5.0
F2014	23.6	26.1	3.2	3.5
F2015	37.8	41.9	5.1	5.7
F2016	27.2	29.6	3.7	4.0

The variance between reported and evaluated net savings is primarily due to the evaluated net to gross ratio being higher than what was assumed for reported savings.

4.4 Findings and Recommendations

Findings

1. Awareness of the PSP-D offers was highest among custom participants and non-participants, as well as SIP participants with a KAM. In terms of individual program components, awareness was highest for energy studies and the role that KAMs play as liaisons for the program.
2. Overall satisfaction with the custom and SIP offers was very high with over 90 per cent of participants rating these offers as excellent or good. Satisfaction was lower among PIP/PSX participants at 83 per cent.
3. Over 80 per cent of the program enabled projects (62 per cent of gross energy savings) reported through the program came from sites with an energy manager.
4. Overall, when comparing sites of similar size, the sites with energy managers completed more projects and achieved more energy savings per project. The relative level of project savings (as a per cent of site energy consumption) was twice as high at sites with energy managers than at sites without: 10 per cent versus 5 per cent for sites with energy consumption higher than 4 GWh/year, and

24 per cent versus 12 per cent for sites with energy consumption less than 4 GWh/year.

5. Forty-six per cent of the program's energy savings were supported by either or both of an energy manager or energy study. Sixty per cent of the program's energy savings occurred at sites that had previously participated in program enabling activities.
6. The lack of a standardized process for tracking customers' program enabling activities in project files made it difficult to identify and assess the influence of individual enabling activities on the project's energy savings unless the case study method was applied during evaluation.
7. The program gross realization rate calculated from M&V results was 99 per cent, indicating that the energy conservation measures largely performed as expected. Three end use level realization rates were estimated: compressed air at 112 per cent, lighting at 101 per cent and other end uses at 89 per cent with relative precision between 6 per cent and 9 per cent at 90 per cent confidence.
8. Expected energy savings averaged 8.5 per cent of site energy consumption across all participants during the six year evaluation period.
9. The average weighted persistence of measures (i.e., the length of time that the savings are reported by the program) was 13.1 years during the evaluation period.
10. The net-to-gross ratio was 97 per cent based on an overall level of free ridership of 14 per cent, participant spillover of 7 per cent and non-participant spillover of 4 per cent.
11. Evaluated net savings during the evaluation period from F2011 to F2016 averaged 108 per cent of reported savings.

Recommendations

Recommendation 1 is for program management and Recommendations 2 and 3 are for future evaluations.

1. In consultation with the Evaluation Department, consider ways to improve the evaluability of the program enabling activities through improved documentation and tracking of energy savings opportunities identified and level of influence of program enabling activities.
2. Consider using a greater sample of case studies to assess influence of program enabling activities on custom projects.
3. Should future evaluations use top-down statistical analysis of facility consumption to estimate savings from Strategic Energy Management, review the approach to evaluating participant spillover to ensure there is no double counting of savings.

4.5 Conclusions

BC Hydro's Power Smart Partner – Distribution program achieved 108 per cent of reported savings during fiscal years F2011 to F2016. The program also achieved high levels of customer awareness and satisfaction.

5 Residential Inclining Block Rate: F2013-F2017

5.1 Introduction

The Residential Inclining Block (**RIB**) rate is a two-step rate structure where BC Hydro's residential customers pay a lower price for electricity consumption up to a certain threshold, and a higher price for electricity consumption beyond the threshold.

The RIB rate went into effect in October 2008 for approximately 1.6 million residential customers. The Step 1 to Step 2 threshold was set at 1,350 kWh per two-month billing period, which was approximately 90 per cent of the median consumption of BC Hydro's residential customers. The Step 2 rate was established at BC Hydro's current estimate of the cost of new energy supply, grossed up for losses, and the Step 1 rate was calculated to achieve revenue neutrality for the residential class. The over-arching objective of the RIB rate was to use price to encourage additional electricity conservation relative to what was achievable through a flat rate structure.

The last evaluation of the RIB rate was conducted in 2013[10] and evaluated the price elasticity of consumption and the electricity conservation impacts in response to the rate's two-step structure, as well as customer awareness, understanding, and response to the RIB rate for the period from October 2008 through March 2012 (the mid-point of F2009 through F2012). This evaluation is a continuation of the 2013 evaluation, and covers April 2012 through March 2017 (F2013-F2017).

5.2 Approach

The evaluation objectives and research questions are shown on the following page.

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[10] BC Hydro (2014) "Evaluation of the Residential Inclining Block Rate F2009-F2012", Revision 2, Power Smart Evaluation, BC Hydro.

Table 11 Evaluation Objectives and Research Questions

Objectives	Research Questions
1. Estimate Price Elasticity	• What is the price elasticity of Step 1 and Step 2 consumption? • Is there a difference in price elasticity between BCH customers and a comparable community without a RIB rate (e.g., New Westminster)? • What is the price elasticity due to natural conservation, as measured by the price response to general rate increases through F2017? • How do the results of research questions related to price elasticity compare to previous research on this topic conducted as part of the last RIB rate evaluation?
2. Estimate the Conservation Impacts of the RIB Rate	• What are the energy savings due to BC Hydro's RIB Rate from F2013 to F2017? • What are the peak demand savings due to BC Hydro's RIB rate from F2013 to F2017? • What are the energy savings due to natural conservation from F2013 to F2017, as measured by the price response to general rate increases?
3. Analyze Differences in Price Elasticity by Customer Characteristics	• Are there differences in price elasticity by region? • Are there differences in price elasticity by dwelling type? • Are there differences in price elasticity by space heating type? • How do the results of research questions related to price elasticity compare to previous research on this topic conducted as part of the last RIB rate evaluation? • Are there differences in price elasticity between winter and summer periods?
4. Evaluate the Customer Response and Understanding of the RIB Rate	• Are there differences in the characteristics or demographics of customers who are never billed in Step 2 compared to those who are sometimes or always billed in Step 2? • What is the level of customer awareness and understanding of the RIB rate? • To what degree do customers believe electricity prices provide an incentive to manage electricity consumption? • To what extent do customers believe the total electricity bill amount provides an incentive to manage electricity consumption? • What is customers' understanding of their prevailing electricity price under the RIB rate structure? • To what extent do customers believe the RIB provides an incentive to manage electricity consumption? • To what extent do RIB aware customers report energy conserving behaviours as compared to non-RIB aware customers? • To what extent do RIB aware customers report implementing longer term capital investment in energy efficiency or conservation as compared to non-RIB aware customers? • Was program participation in DSM programs different between customers aware / not aware of the RIB rate? • Did low income customers have a different perception or response to the RIB Rate? • Does the RIB rate have any impact on customers' decisions on fuel switching from electricity to thermal fuels? • Is the RIB rate perceived as a barrier to electrification? • Has customers' response/acceptance to RIB changed over time? • Do customers support the RIB rate? • Do notifications / alerts on Step 2 have an impact on customers' consumption behaviour? • How do the results of research questions related to customer response and understanding of the RIB rate compare to previous research on this topic completed as part of the last RIB rate evaluation or REUS surveys?

The table below summarizes the data sources and methods employed in this study for each evaluation objective.

Table 12 Summary of Evaluation Objectives, Data Sources and Methods

Evaluation Objective	Data Sources	Methods
1. Estimate Price Elasticity	• BC Hydro billing data from April 2004 to December 2016, including electricity consumption, space heating fuel, region and dwelling type by account • BC Hydro residential rate prices from April 2004 to December 2016 • BC Hydro DSM expenditures and savings, from 2004 to 2017 • BC Consumer Price Index data from April 2004 to December 2016 obtained from Statistics Canada • BC real disposable income from April 2004 to December 2016 from BC Stats • Heating and cooling degree days by region from April 2004 to December 2016 • New Westminster customer billing data from 2005 to 2016 and customer information on heating fuel and dwelling type	• Econometric modelling of price elasticity
2. Estimate the Conservation Impacts of the RIB Rate	• Data and results from Objective 1 • BC Hydro residential rate class load shape	• Calculation based on price elasticity and rate class load shape
3. Analyze Differences in Price Elasticity by Customer Characteristics	• Same as Objective 1	• Same as Objective 1
4. Evaluate the Customer Response and Understanding of the RIB Rate	• 2012 customer survey (n = 2,468) • 2017 customer survey (n = 3,307) • 2014 Residential End-Use Study (n=7,318) • 2017 Residential End-Use Study (n=6,929) • BC Hydro billing data from F2012 and F2017 • Data on customer sign-ups for Step 2 alerts • BC Hydro residential DSM program tracking data	• Cross tabulations of survey responses • Linking of survey responses to respondent billing history • Difference in proportions z-tests • Difference of Means Tests using Analysis of Variance

Objective 1, estimating price elasticity, and Objective 3, analyzing elasticities differences by customer characteristics, were addressed through econometric modeling which utilized a variety of data sources including electricity consumption and Statistics Canada data. Objective 2 was a calculation using the results from Objective 1.

Objective 4, related to evaluating customer response and understanding of the RIB rate, was largely addressed through analysis and comparison of the results from two similar residential customer surveys which were delivered in 2012 and 2017.

5.3 Results

Objective 1: Price Elasticity

Step 1 consumption represents the consumption of those customers whose bi-monthly usage does not exceed the 1,350 kWh threshold. The Step 1 price elasticity of these customers was estimated to be -0.14. The previous RIB evaluation in 2013 was unable to detect a Step 1 price elasticity over the F2009 to F2012 period, nor did a subsequent analysis over the F2009 to F2015 period. Due to the fact that Step 1 price elasticity could not be detected for the F2009 to F2015 period, the estimate of -0.14 was only seen to be applicable to F2016 and F2017.

Step 2 consumption represents the consumption of those customers whose bi-monthly usage exceeds the 1,350 kWh threshold. The Step 2 price elasticity of these customers was estimated to be -0.08, which is at the low end of the range estimate of -0.08 to -0.13 from the 2013 evaluation. The current estimate indicates that in comparison to the earlier years of the RIB rate, customers who were exposed to Step 2 prices in recent years may have become less price responsive—measured by percentage change in consumption—to Step 2 price increases. It also indicates that their capacity and options to conserve energy while facing price increases may have been more limited in recent years. Meanwhile, Step 1 consumption has become price sensitive in recent years.

Table 13 Step 1 and Step 2 Price Elasticity Estimates

Time Series Analyzed	Step 1 Elasticity	Step 2 Elasticity
F2005-F2012	Not statistically significant	-0.08 to -0.13***[11]
F2005-F2015[12]	Not statistically significant	Not analyzed
F2005-F2017	-0.14***	-0.08***

*** indicates statistically significant at 95% confidence level.

The price elasticity of electricity consumption under a flat rate is used to calculate the natural conservation impact that would be achieved by general rate increases as per BC Hydro's approved Revenue Requirements. This flat rate price elasticity is used to estimate the baseline conservation that would have occurred in the absence of the RIB rate. The flat rate price elasticity could not be estimated through econometric analysis. A range estimate between the Step 1 and Step 2 elasticities was adopted (-0.08 to -0.14) to calculate the natural conservation impact. Since the Step 1 price elasticity estimate of -0.14 was only applicable to F2016 and F2017, the range estimate of the flat rate elasticity was similarly applied to F2016 and F2017 only. In the absence of an empirical estimate of flat rate elasticity in the F2013 to F2015 period, the planning assumption of -0.05[13] was applied to those years.

Objective 2: Conservation Impacts of the RIB Rate

In order to evaluate additional energy conservation achieved under the RIB rate relative to the flat rate, the energy impacts of the Step 1, Step 2, and the flat rate price response were calculated separately. The baseline scenario was considered natural conservation achieved under the flat rate due to general rate increases and the RIB rate structural savings were calculated as the sum of the Step 1 and Step 2 energy impact, less the natural conservation impact. The annual incremental structural savings from the RIB rate between F2013 and F2015 are presented below. The calculations are based on the

11 BC Hydro (2014).
12 In 2016, an analysis was conducted to evaluate the Step 1 price elasticity for the period of F2005-F2015. This analysis did not produce statistically significant results. The modelling outputs from this analysis were included in Appendix D.
13 Orans, R (2008), the source and reasons for adopting this assumption were provided in the expert testimony of the 2008 BC Hydro Long-Term Acquisition Plan, Appendix E.

value of Step 1 elasticity (zero), Step 2 elasticity (-0.08) and assumed flat rate elasticity (-0.05).

Table 14 RIB Rate Savings F2013-F2015

Fiscal Year	Step 1 Price Impact (GWh)	Step 2 Price Impact (GWh)	Natural Conservationz (GWh)	RIB Structural Savings (GWh)
	A	B	C	(A + B - C)
Elasticity	**0.00**	**-0.08**	**-0.05**	**-**
F2013	-	49	24	23
F2014	-	16	13	3
F2015	-	74	62	13

Given the potential range in flat rate elasticity (-0.08 to -0.14; assuming that it lies between the estimates of Step 1 and Step 2 elasticity), natural conservation and RIB structural savings in F2016 and F2017 could not be estimated with precision. Table 15 shows the calculation of natural conservation and RIB structural savings using four different flat rate elasticities: -0.08, -0.09, -0.10 and -0.14. Based on this calculation, savings appear to decrease as flat rate elasticity increases. Based on the results derived through the range estimate, the evaluated RIB energy savings in F2016 and F2017 were deemed to be small or zero, as shown in Table 16 below.

Table 15 RIB Rate Savings F2016-F2017

	Step 1 Price Impact (GWh)	Step 2 Price Impact (GWh)	Natural Conservation (GWh)				RIB Structural Savings (GWh)			
	A	B	C				(A + B- C)			
Elasticity	**-0.14**	**-0.08**	**-0.08**	**-0.09**	**-0.10**	**-0.14**	**-0.08**	**-0.09**	**-0.10**	**-0.14**
F2016	26	45	60	67	75	104	11	4	(3)	(33)
F2017	13	23	29	33	37	52	6	2	(2)	(16)

Based on the estimates of Step 1 (-0.14), Step 2 (-0.08), and the adopted flat rate elasticity range (-0.08 to -0.014) , the energy and peak demand saving impacts attributed to the RIB rate were calculated as presented in the table below.

Table 16 Reported and Evaluated RIB Rate Savings

	Energy Savings (GWh)		Peak Demand Savings (MW)	
Fiscal Year	Reported	Evaluated	Reported	Evaluated
F2013	42	23	9	5
F2014	19	3	4	1
F2015	59	13	12	3
F2016	29	0 to 11	6	0 to 2
F2017	8	0 to 6	2	0 to 1

Two major factors contribute to the variance between reported and evaluated RIB rate savings. First, the Step 2 price elasticity of -0.08 was smaller (in absolute value) than the planning assumption of -0.1. Second, the flat rate elasticity range estimate applied to F2016 and F2017 was higher (in absolute value) than the value used in the forecast of RIB savings (-0.05).

Objective 3: Price Elasticity by Customer Characteristics

Additional analyses were conducted to determine if separate price elasticity estimates could be identified based on season or specific customer characteristics such as region, dwelling type, and space heating fuel. Those results are presented in Table 17, where each category (region, dwelling type, space heating, winter vs summer) shows the results of a separate regression analysis. The results included in Table 17 show that Step 1 and Step 2 price elasticity varied by region, dwelling type, space heating type and winter versus summer. In some instances, the elasticity estimate was not statistically significant.

Table 17 Step 1 and Step 2 Price Elasticity by Customer Characteristics

Customer Segment	Step 1 Elasticity	Step 2 Elasticity
Region		
Lower Mainland	-0.22***	Not statistically significant
Vancouver Island	-0.18***	-0.12***
Southern Interior	Not statistically significant	Not statistically significant
North	-0.23***	Not statistically significant
Dwelling Type		
Single Family Dwelling	-0.04***	-0.08***
Row/Townhouse	-0.14***	-0.10***
Apartment	-0.26***	-0.07***
Mobile Home	-0.12***	-0.09***
Space Heating		
Electric	-0.11***	Not statistically significant
Non-Electric	-0.18***	-0.17***
Winter vs. Summer	Not statistically significant	More negative by 0.05 in winter than in summer (e.g., if summer price elasticity is -0.07, winter is -0.12)

*** indicates statistically significant at 95% confidence level.

Objective 4: Customer Response and Understanding of the RIB Rate

Between F2013 and F2017, the proportion of customer households that never incurred Step 2 electricity consumption remained generally unchanged at approximately 30 per cent. However, the proportion that sometimes incurred Step 2 consumption (one to 11 months) increased from 39 per cent to 48 per cent while the proportion that always incurred Step 2 consumption (12 months) decreased from 30 per cent to 22 per cent.

Between 2012 and 2017, there was an increase from 53 per cent to 64 per cent in the proportion of customers who believed that BC Hydro's residential electricity prices were too high. In fact, for customers that never incurred electricity consumption beyond Step 1, there was no longer a majority in 2017 – as there was in 2012 – who felt that prices were ‘about right’. The largest segment of these customers now believed prices were too high.

At 49 per cent in 2012 and 47 per cent in 2017, there has been no meaningful change over the past five years in the proportion of customer respondents who knew that BC Hydro charges their consumption of electricity on an inclining block rate. For these particular customers, they believed that their total bill amounts serve as the greatest incentive to manage their consumption of electricity, followed by electricity prices and then followed by the rate structure. In fact, the RIB rate structure was seen as less of an incentive in 2017 than it was in 2012.

In the 2017 survey, customers previously aware of the RIB rate were more likely than others to have completed a home energy efficiency upgrade in the previous three years, to have participated in at least one of BC Hydro’s conservation programs, and to have outperformed other customers on many in-home conservation behaviours. However, it could not be ascertained through the research if and to what extent awareness of the rate structure led to the decisions to engage in these activities.

Customer support of BC Hydro’s RIB rate decreased from 59 per cent to 55 per cent between 2012 and 2017. Support continues to measure highest among customers who never incur Step 2 electricity consumption in a fiscal year.

5.4 Findings and Recommendations

Findings

Price Elasticity

1. The overall average Step 1 price elasticity was estimated to be -0.14 for F2016 and F2017. Previous analyses, covering the time period of F2005-F2012 and F2005- F2015, were unable to detect Step 1 price elasticity, likely due to relatively low Step 1 prices and small changes in the Step 1 price in earlier years. As a result, Step 1 price elasticity was assumed to be zero in the calculation of energy

savings for F2013 to F2015, which was the same approach used in the 2013 evaluation.

2. Step 2 price elasticity was estimated at -0.08, which is at the low end of the range from the previous evaluation (-0.08 to -0.13). This result may suggest that customer response to the Step 2 price has diminished over time.
3. A range of -0.08 to -0.14 was adopted to estimate natural conservation due to general rate increases under a flat rate in F2016 and F2017. This range spans the empirical estimates for Step 1 and Step 2 price elasticity for F2016 and F2017. In the absence of empirical estimates of flat rate and Step 1 price elasticities in the F2013-F2015 period, the planning assumption of -0.05 was applied for natural conservation in those years.
4. To obtain a proxy estimate of the flat rate elasticity, an analysis of residential consumption data from F2005 to F2016 in New Westminster, a jurisdiction serviced under a flat rate, was conducted. However, it did not produce a statistically significant estimate of flat rate elasticity.

Conservation Impacts of the RIB Rate

1. The annual incremental structural savings from the RIB rate were evaluated at 23 GWh, 3 GWh, and 13 GWh between F2013 and F2015.
2. Given the range of estimated flat rate elasticity due to general rate increases, (-0.08 to -0.14), definitive results for natural conservation and RIB structural savings in F2016 and F2017 could not be determined. Calculated RIB structural savings in F2016 and F2017 decreased as the flat rate elasticity increased. As a result, RIB structural savings in F2016 and F2017 were deemed to be small or zero.

Differences in Price Elasticity by Customer Characteristics

1. Price elasticity by region: Step 1 price elasticity was detected in three out of four geographic regions compared to none in the previous evaluation.[14] Step 2 price elasticity was detected in one region compared to all four regions in the previous evaluation. These results indicate that the Step 2 price is no longer a strong factor in determining electricity consumption in a large part of BC Hydro's service area.
2. Price elasticity by dwelling type: Step 1 price elasticity was identified in four dwelling types compared to none in the previous evaluation. Relative to the previous evaluation, Step 2 price elasticity decreased among single family dwellings and increased among row or townhouses and apartments.
3. Price elasticity by space heating type: Step 1 price elasticity was detected in households with electric and non-electric primary space heating, contrary to the previous evaluation. Step 2 price elasticity was only detected in households with non-electric primary space heating, and at a lower level than in the previous evaluation. The previous evaluation detected Step 2 price elasticity in both types of households. This finding suggests that energy savings induced by price changes from F2013 forward may have come from sources other than electric space heating.
4. Price elasticity in winter vs. summer: The analysis found no statistically significant difference in Step 1 price elasticity between winter and summer and a difference of -0.05 in Step 2 price elasticity—with elasticity being more negative in winter than in summer. This result indicates that for Step 2 consumption, the price sensitivity and price impact are greater in winter than in summer.

Customer Response, Awareness, and Understanding

1. From F2013 through to F2017, the proportion of customer households that incurred at least some Step 2 electricity consumption remained generally even at 70 per cent. Through these five years, however, there was a decrease from

[14] BC Hydro (2014).

30 per cent to 22 per cent in the proportion that were into Step 2 in each month of a fiscal year.

2. Between 2012 and 2017, there was an increase from 53 per cent to 64 per cent in the proportion of customers who felt that BC Hydro's residential electricity prices were too high. Furthermore, the extent that customers felt this way was highly correlated with their exposure to Step 2 electricity consumption.
3. For customers that never incurred electricity consumption beyond Step 1, there was no longer a majority in 2017 – as there was in 2012 – who felt that prices were 'about right'. The largest segment of these customers now believed prices were too high. Their beliefs around the price of electricity in each of the 2012 and 2017 surveys help to explain why a Step 1 price elasticity was not detected until F2016 and F2017 as customers became increasingly responsive to increases in the Step 1 price.
4. Customers' unaided awareness that BC Hydro charges household consumption of electricity on an inclining block rate has gone generally unchanged over the past five years, measuring 49 per cent in 2012 and 47 per cent in 2017.
5. For customers previously aware of the RIB rate in each of the 2012 and 2017 surveys, their total bill amounts emerged as serving more of an incentive to manage their consumption of electricity than did electricity prices or the rate structure. In fact, the inclining block rate was considered to be less of an incentive in 2017 than it was in 2012, which is consistent with the findings regarding price elasticity and conservation.
6. Customers previously aware of the RIB rate in the 2017 survey were more likely than others to have completed a home energy efficiency upgrade in the previous three years, to have participated in at least one of BC Hydro's conservation programs, and to have outperformed them on many in-home conservation behaviours. However, it could not be ascertained through the research if and to

what extent awareness of the rate structure led to the decisions to engage in these activities.

7. The total proportion of customers who support the RIB rate – including those who may have learned about it for the first time in the survey – has decreased from 59 per cent to 55 per cent over the past five years. Support continues to measure highest among customers who never incur Step 2 electricity consumption.

Recommendations

1. Consider whether the existing rate structure continues to serve BC Hydro's business objectives and meet customer needs, given that the current RIB rate structure appeared to yield little or no energy savings in F2016 and F2017.
2. Given the finding that larger consuming customers are more price responsive in the winter than in summer, consider exploring the value of a seasonal rate, with different pricing and consumption thresholds in the winter.
3. Consider the value of targeting small electricity consumers (e.g., those living in apartments) with existing or new DSM program offers, given their increased response to price changes in recent years.

5.5 Conclusions

Although awareness of the RIB rate has remained relatively unchanged over the past five years at just under 50 per cent among all residential customers, the survey analysis has shown that a greater proportion of small customers now feel that electricity prices are too high and the econometric analysis has indicated that they have become more responsive to price changes.

Overall, the RIB rate appears to have achieved its objective of encouraging conservation through the customer response to higher marginal prices. However, the effectiveness of the RIB rate in yielding electricity savings appears to have diminished over time.

6 Residential Retail Program – Consumer Electronics and Appliance Rebate Offers: F2011 to Second Quarter F2015

6.1 Introduction

This report provides the results from an evaluation of the impact of the Residential Retail Program for the period from F2011 through to the second quarter of F2015 (i.e., April 2010 through September 2014). The Residential Retail Program was a multi-year energy acquisition and market transformation initiative that facilitated the use of more energy efficient products by BC Hydro's residential customers. The focus of this evaluation report is on the Consumer Electronics offer and the Appliance Rebate Offer.

Consumer Electronics

The Consumer Electronics offer was launched in 2009 with an objective to reduce the electricity consumption resulting from the increased use of home electronics. When the offer was introduced, it consisted of two main components: new TV sales and old TV recycling. A third component involving set-top boxes was introduced in F2013.

The new TVs component provided a mid-stream incentive to participating retailers for the sale of high efficiency TVs. In-store promotional materials were made available to retailers. Training was offered to sales staff to increase their knowledge of the features and benefits of high efficiency TVs.

Recycling old TVs was promoted through advertising and outreach activities to encourage homeowners to unplug and recycle older used TVs. Outreach activities occurred in F2013 (April and January) and in F2014 (February) in selected communities inviting households to drop off their unwanted TVs at specific locations. A pick-up service was also offered in some communities in F2013 and F2014 in partnership with 1-800 Got Junk.

BC Hydro partnered with TELUS to investigate ways to increase the efficiency of set-top boxes installed by the company among its customer base. BC Hydro provided an incentive to TELUS to enable the auto-power down feature through a software update across its deployed set-top boxes in F2013, in British Columbia and Alberta. All new boxes purchased after September 2012 were also enabled with the auto-power down feature.

Appliance Rebate Offer

The objective of the appliance rebate offer was to obtain energy savings by encouraging the purchase of the most energy efficient refrigerators, freezers, clothes washers and dishwashers. The program employed a variety of promotional strategies including advertising, point of sale material and improved labelling of products. In addition, training was offered to sales staff to increase their knowledge of the features and benefits of high efficiency appliances. Rebates were provided to purchasers of qualifying refrigerators, freezers, clothes washers, and dishwashers. The appliance rebate offer was introduced in 2008 and operated on a year-round basis until the end of October 2013.

6.2 Approach

Shown below are the evaluation objectives and research questions.

Table 18 Evaluation Objectives and Research Questions

Objectives	Research Questions
1. Program Effectiveness	• How effective were each of the offers at reaching their target markets? • How influential was the program on customers' decisions to purchase high efficiency TVs or appliances, or to recycle their old TVs? • How easy was the process to apply for an appliance rebate? • How did appliance rebate participants rate the dollar value and speed of receiving the rebate? • How did retail partners rate the influence of the program on promoting sales of energy efficient TVs and appliances, and installing energy efficient set-top boxes? • How satisfied were retail partners with the consumer electronics and appliances offers?
2. Market Trends	• What were the sales trends for new TVs? • What were the stocking and price trends among energy efficient TVs and appliances? • What were trends in the types of consumer electronics and appliances installed in BC Hydro residential customer homes?
3. Evaluated net electricity savings – Consumer Electronics	• What were the gross and net electricity savings for new TVs, set-top boxes and recycled TVs? • To what extent could sales of energy efficient TVs, installation of energy efficient set-top boxes and recycling of old TVs be attributed to the Consumer Electronics offer? • To what extent was there spillover associated with the new TVs components of the offer? • How do evaluated net electricity savings compare to reported savings, and what are the reasons for any variance?
4. Evaluated net electricity savings – Appliance Rebate	• What was the rate of free ridership for each type of appliance? • To what extent was there spillover associated with the rebate offer? • What were the gross and net electricity savings for each appliance? • How do evaluated net electricity savings compare to reported savings, and what are the reasons for any variance?

Data sources and methods used to address each of the objectives are summarized in Table 19.

Table 19 Evaluation Objectives, Data Sources and Methods

Objectives	Data sources	Method
1. Program effectiveness	• 2014 Consumer Electronics Survey (n=501) • 2014 Appliance Program Participant Survey (n=1,119) • 2012, 2013, 2014 Retail Partners Surveys (n = 5, 8, 13) • 2015 Cable TV Service Provider interview (n=1)	• Frequency distributions • Cross tabulations • Qualitative analysis
2. Market Trends	• Annual Household Electronics and Appliances Floor Stock Study from 2001 to 2014 (~ 40 stores per year) • Residential End Use Surveys from 2001 to 2014 (n = 4,338 to 7,907 depending on year) • Sales data for new TVs in BC (January 2011 to December 2015)	• Frequency distributions • Cross tabulations • Trend analysis
3. Evaluated net electricity savings – Consumer Electronics	• 2014, 2015 Consumer Electronics Survey (n = 501; 500) • 2012, 2014 Residential End Use Survey (n = 7,907; 7,451) • Sales data for new TVs in BC, from January 2011 to December 2015 • Annual Household Electronics and Appliances Floor Stock Study 2001 to 2014 (~ 40 stores) • 2008 TV and Set-top Box Survey (n=641) • 2010 Residential Monitoring Study (48 homes) • 2015 Consumer Electronics Metering Study (53 homes) • Technology and Market Profile: Consumer Electronics. Marbek (2006) • 2015 Cable TV Service Provider interview (n=1)	• Engineering algorithms • Load shape analysis • Stock and flow model estimates • ARIMA modelling • Common practices baseline using market data analysis • Survey-based program attribution estimation
4. Evaluated net electricity savings – Appliance Rebate	• Program Tracking Data • Annual Household Electronics and Appliances Floor Stock Study 2001 to 2014 (~ 40 stores) • 2014 Appliance Rebate Participant Survey (n=1,119)	• Engineering algorithms • Survey-based participant free rider and spillover estimation

6.3 Results

Objective 1: Program Effectiveness

New Televisions

The program incented between 12 per cent and 30 per cent of all TVs sold annually in B.C. during the evaluation period. It also incented 94 per cent of the high efficiency TVs sold in F2012 and more than half of those sold in F2013 (55 per cent). Aggregating survey results from all years, eight out of 15 retailers indicated that the incentive was very or somewhat influential on their stocking decisions regarding high efficiency TVs. Overall, retail partners were satisfied with BC Hydro's promotions of new TVs.

Of those households that had recently purchased a new TV, 22 per cent recalled seeing promotional materials. Of those who recalled the promotion, 82 per cent purchased a high efficiency model and 94 per cent in that group indicated the promotional materials had influenced their decision to purchase that particular model.

Recycled TVs

Twenty-one per cent of respondents to the 2014 Consumer Electronics Survey reported they recalled seeing, hearing or reading BC Hydro information about recycling TVs. Of those who had recycled a TV after being exposed to the promotional information, 75 per cent reported the campaign influenced their decision to recycle.

Set-top Boxes

TELUS rated BC Hydro's encouragement and financial support as very important to enabling the auto-power down feature of their set-top boxes and the incentive provided the financial support needed to activate the auto-power down feature. As explained in the interview, TELUS had not considered energy efficiency prior to being approached by BC Hydro.

Appliances

Results of the Appliance Program Participant Survey show that 51 per cent of respondents first learned of the appliance rebate from a salesperson on the floor of the retail store, and 26 per cent learned of the rebate through in-store stickers and labels. Overall, 88 per cent of respondents reported that their experience with the program was good or excellent, including the ease of applying for the rebate. While still favourable, ratings of the speed of receiving the rebate cheque were slightly lower, with 75 per cent giving ratings of good or excellent. The total dollar amount of the rebate was rated lower with 63 per cent of participants assessing the rebate amount favourably. Reported influence of the customer appliance rebate on retailers was mixed.

Objective 2: Market Trends

Televisions

TVs were, and continue to be, a rapidly changing technology. The type of TV installed in BC Hydro customers' homes has changed substantially over the past ten years, in particular the move away from the standard CRT TV to LCD and LED-LCD TVs. The proportion of households with a CRT TV plummeted to 29 per cent in 2014 from 98 per cent in 2001. This decline was accompanied by a rapid increase in LCD models, rising from 8 per cent of households in 2006 to 76 per cent in 2014.

In terms of total TV sales in BC, there has been a declining trend from the beginning of 2011 to the latter part of 2015, and the sale of non-Energy Star televisions has been in general decline since F2012. The price of TVs with higher energy efficiency ratings tended to be slightly higher than the average of all Energy Star models.

Appliances

In 2014, almost all households (96 per cent) had at least one refrigerator, the majority of which were auto-defrost. Fifty per cent of households in the BC Hydro service territory had at least one freezer in 2014, down from 63 per cent in 2001.

In 2010, 2012 and 2014, approximately 90 per cent of households in BC had a clothes washer. The type of clothes washers installed by residential customers also changed over the evaluation period with 53 per cent of households in 2014 reported having a top-load clothes washer, down from 90 per cent in 2001. For the past ten years, slightly more than three-quarters of households in the BC Hydro service area had a dishwasher.

The average proportion of Energy-Star rated appliances on display in BC retail stores from 2009 to 2014 was 76 per cent for refrigerators, 78 per cent for clothes washers and 84 per cent for dishwashers. Energy Star freezers represented an average of 43 per cent of displayed models.

Objective 3: Evaluated net electricity savings – Consumer Electronics

New Televisions

Evaluated net savings were calculated by multiplying the total number of incented televisions by the average unit savings in each fiscal year and adjusted for cross effects. A separate analysis did not detect any lasting trends in the sales of high efficiency TVs and there was no spillover associated with the new TV sales component of the program. Note that the common practice baseline approach accounts for any free ridership that might be present. Table 20 summarizes the inputs and results for evaluated net savings as well as the reported net savings for high efficiency television sales.

Table 20 Evaluated and Reported Net Savings for New TVs

Fiscal Year	Total Units Incented	Avg. Unit Savings (kWh/year)	Cross Effect Adjustment (1-0.03)	Evaluated Net Savings (GWh/year)	Reported Net Savings (GWh/year)
F2011	58,998	34	0.97	1.9	3.2
F2012	120,360	16	0.97	1.9	6.3
F2013	74,620	31	0.97	2.2	2.8
F2014	26,098	36	0.97	0.9	1.1
Total*	**280,076**	**--**	**--**	**7.0**	**13.3**

*Columns may not sum to total due to rounding.

Evaluated net savings for the evaluation period were 7.0 GWh per year, or roughly half of the reported net savings of 13.3 GWh per year. The greatest variance between reported and evaluated savings occurred in F2012 when incented TVs accounted for 94 per cent of high efficiency TV sales in BC and when unit savings were the smallest. It is not conclusive whether the convergence of rebated and total market sales suggests high free ridership in that year or is indicative of the influence previous program efforts had on retailers to stock more of the high efficiency TVs.

Set-top Boxes

The net to gross ratio for set-top boxes was evaluated as 100 per cent, based on the results of the service provider interview. Evaluated and reported net savings for set-top boxes are presented in Table 21.

Table 21 Set Top Box Evaluated and Reported Net Savings

Fiscal Year	Evaluated Gross Savings (GWh/year)	Net to Gross Ratio	Evaluated Net Savings (GWh/year)	Reported Net Savings (GWh/year)
F2013	4.1	1	4.1	5.1
F2014	0.6	1	0.6	0.7
F2015 (Q1-Q2)	0.3	1	0.3	0.4
Total	**5.0**	--	**5.0**	**6.2**

As shown in the above table, evaluated net savings for the evaluation period were slightly lower than reported. The variance between evaluated and reported net savings is due to reported savings assuming higher unit savings and more time spent in active mode relative to evaluated results.

Recycled TVs

Program tracking data was not available for recycled TVs because this component only consisted of promotional activities. Evaluated gross savings were based on information garnered from several sources and were adjusted for a cross effect factor of 3 per cent. The gross savings were further adjusted by an attribution score to account for program influence on recycling. The attribution score was based on self-report by those who had recycled a TV and calculated to be 5 per cent. Evaluated net savings were 6.5 GWh for the evaluation period, which was almost the same as reported net savings, as summarized in Table 22.

Table 22 Evaluated and Reported Gross and Net Savings for Recycled Televisions

Fiscal Year	Evaluated Gross Savings (GWh/year)	Cross Effect Adjustment (1 - .03)	Attribution Score	Evaluated Net Savings (GWh/year)	Reported Net Savings (GWh/year)
F2011	22.4	0.97	0.05	1.1	1.1
F2012	22.4	0.97	0.05	1.1	1.9
F2013	42.9	0.97	0.05	2.1	2.0
F2014	42.9	0.97	0.05	2.1	1.6
Total	**130.6**	**--**	**--**	**6.5***	**6.6**

* Columns may not sum to total due to rounding.

Summary of Net Savings Results for Consumer Electronics

The evaluated and reported net savings for each component of the consumer electronics offer are summarized in Table 23. The share of total evaluated savings was fairly evenly split across the three components of the offer.

Table 23 Reported and Evaluated Net Savings for the Consumer Electronics Offer: F2011 - F2015, Q1-Q2 (GWh/year)

	New TVs		Recycled TVs		Set-top Boxes		Total	
Fiscal Year	Reported	Evaluated	Reported	Evaluated	Reported	Evaluated	Reported	Evaluated
F2011	3.2	1.9	1.1	1.1	--	--	4.3	3.0
F2012	6.3	1.9	1.9	1.1	--	--	8.2	3.0
F2013	2.8	2.2	2.0	2.1	5.1	4.1	9.9	8.4
F2014	1.1	0.9	1.6	2.1	0.7	0.6	3.4	3.6
F2015 (Q1-Q2)	--	--	--	--	0.4	0.3	0.4	0.3
TOTAL*	**13.3**	**7.0**	**6.6**	**6.5**	**6.2**	**5.0**	**26.2**	**18.3**

* Columns may not sum to total due to rounding.

Objective 4: Evaluated electricity savings – Appliance Rebate

Due to data limitations, an estimate of net savings attributable to the program, inclusive of the program's effect on retailers, could not be developed. Therefore, evaluated net savings have not been calculated for the appliance rebate component of the program, as program attribution could not be fully estimated.

Evaluated gross savings were calculated by multiplying average unit savings by the number of units rebated and adjusting for cross effects, where applicable. The cross effect factor applied to evaluated savings was 1.7 per cent for refrigerators and 0.5 per cent for freezers. Cross effect values used in the reported savings varied from 9.7 per cent to 1.8 per cent for refrigerators and 2.7 per cent to 0.3 per cent for freezers.

As shown in Table 24, evaluated gross savings were 19.3 GWh per year. Clothes washers achieved the largest savings, accounting for 79 per cent of the total gross savings. Evaluated gross savings were higher than reported gross savings, which were 10.2 GWh per year. The variance between evaluated and reported gross savings is largely due to the inclusion of additional energy savings from clothes drying associated with high efficiency clothes washers.

Table 24 Evaluated and Reported Gross Savings: F2011 -F2015, Q1-Q2 (GWh/year)

Fiscal Year	Refrigerators	Freezers	Dishwashers	Clothes Washers	Total Evaluated Gross Savings	Total Reported Gross Savings
F2011	0.8	0.5	0.1	4.5	**5.9**	**3.9**
F2012	0.5	0.4	0.2	4.9	**6.0**	**2.3**
F2013	0.7	0.2	0.2	3.7	**4.8**	**2.5**
F2014	0.4	0.2	<0.1	1.8	**2.4**	**1.3**
F2015 (Q1-Q2)	<0.1	--	--	0.3	**0.3**	**0.2**
Grand Total*	**2.4**	**1.3**	**0.4**	**15.2**	**19.3**	**10.2**

*Columns may not sum to total due to rounding.

The evaluation found free ridership, from the perspective of customers who received a rebate, to be in the range of 71 per cent to 76 per cent for all appliances across all fiscal years in the evaluation period. The free rider analysis captured the purchasers' perspectives of program influence on their purchase decisions and focused mainly on the rebate. Participant spillover was estimated to be negligible on an annual basis (less than 1 per cent per year) and totaled 0.1 GWh per year over the evaluation period. Data collected from non-participants were insufficient to reliably estimate non-participant spillover.

The appliances rebate offer was designed to influence both retailers and consumers. Retailer engagement, education and training activities were intended to influence retail partners to increase the stocking of high efficiency products and to improve the positioning and promotion of these products. BC Hydro's advertising and promotional activities also aimed to improve customers' awareness of high efficiency options and, in conjunction with the rebate, influence their decision to purchase high efficiency appliances. Data collected through the retailer surveys was intended to measure the indirect attribution of energy efficient appliance sales to the program via its influence on retailer stocking, pricing and selling practices. Due to data limitations, an estimate of the program's effect on retailers could not be developed.

Summary of Savings Results for the Residential Retail Program

Presented in Table 25 are the annual incremental and peak demand savings associated with the consumer electronics program component.

Table 25 Summary of Reported and Evaluated Net Energy and Peak Demand Savings for Consumer Electronics

	Net Energy Savings (GWh/year)		Net Peak Demand Savings (MW)	
Fiscal Year	Reported	Evaluated	Reported	Evaluated
F2011	4.3	3.0	1.1	0.7
F2012	8.2	3.0	2.0	0.7
F2013	9.7	8.4	2.4	2.0
F2014	4.0	3.6	1.0	0.9
F2015 (Q1-Q2)	0.6	0.3	0.1	0.1
TOTAL	**26.8**	**18.3**	**6.5**	**4.4**

*Columns may not sum to total due to rounding.

Gross peak demand savings were estimated by multiplying evaluated gross energy savings by the ratio of BC Hydro's system peak demand, in MW, to annual energy consumption, in GWh, derived from residential end-use load shapes. The reported and evaluated peak demand savings for each offer are presented in Table 26.

Table 26 Summary of Reported and Evaluated Gross Energy and Peak Demand Savings for Appliances

	Gross Energy Savings (GWh/year)		Gross Peak Demand Savings (MW)	
Fiscal Year	Reported	Evaluated	Reported	Evaluated
F2011	3.9	5.9	0.7	1.0
F2012	2.3	6.0	0.4	1.0
F2013	2.5	4.8	0.5	0.8
F2014	1.3	2.4	0.2	0.4
F2015 (Q1-Q2)	0.2	0.3	0.0	0.1
TOTAL*	**10.2**	**19.3**	**1.8**	**4.0**

*Columns may not sum to total due to rounding.

6.4 Findings and Recommendations

Findings

Program Effectiveness

1. There was evidence to suggest the program had some influence on retailers' decisions regarding stocking and display of high efficiency TVs. However, the evidence was too weak to ascribe any program effects on retailer behaviours and subsequent influences on consumer decision-making and purchases.
2. Partnerships with BC Hydro to deliver the program were successful. Retail partners reported high levels of satisfaction with the new TV and appliance rebate components of the program. The partnership with TELUS was particularly successful as BC Hydro played the key role in identifying a way for TELUS to improve the energy efficiency of set-top boxes installed in their customers' homes.
3. Survey results for the appliance rebate offer indicate that retailer activities and BC Hydro promotional activities reached the target market of residential customers thinking of purchasing a new appliance. In contrast, survey results suggest that the promotional activities of the consumer electronics offer were more limited in reach. However, the influence of the messaging among those who recalled seeing it was high for all three components.

4. Participants in the appliance rebate offer had a positive experience, rating the qualification and application processes as easy to navigate. They were somewhat less satisfied with the amount of time it took to receive the rebate and the rebate amount, but responses were positive overall.

Market Trends

1. There has been a substantial change in the types of TVs installed in BC Hydro customers' homes over the past ten years, with CRT models steadily becoming less prominent. Overall, TV sales declined over the evaluation period.
2. Characteristics of clothes washers and refrigerators have been changing since 2001. The share of households with front-load and top-load clothes washers has converged towards 50 per cent each in 2014. Overall, the percentage of households that have at least one freezer has declined, with chest freezers becoming less popular.
3. In terms of retailer showroom presence, the shares of energy efficient appliances (i.e., Energy Star) fluctuated due to changes in the Energy Star ratings. However, a high majority of refrigerators, clothes washers and dishwashers were Energy Star, as were a smaller share of freezers. No clear price trends for energy efficient appliances were identified.

Evaluated Net Electricity Savings – Consumer Electronics

1. Overall, evaluated net savings for the consumer electronics offer were 31 per cent lower than reported for the evaluation period (18.3 GWh per year as compared to 26.8 GWh per year). The largest difference between reported and evaluated savings occurred in new TVs and can be ascribed to the convergence of the energy efficiency of program qualifying TVs and the overall TV market. The rapidly changing television market made it challenging for the program to stay ahead of the market in terms of new technologies and higher levels of energy efficiency. The effect of program activities on TV retail partner stocking, positioning and sales efforts was not fully captured from the data sources available to this evaluation.

2. Using information from several different sources, the evaluation estimated a total 812,831 TVs were recycled over the period from F2011 to F2014. Approximately 5 per cent of gross savings from these recycled TVs could be attributed to program activities, as would be expected given that the initiative was limited to advertising and outreach activities.

Evaluated Electricity Savings – Appliances

1. Evaluated gross savings were close to double that of reported savings for the appliances rebate offer (19.3 GWh as compared to 10.2 GWh). Overall, clothes washers accounted for 59 per cent of appliance rebates and 79 per cent of the evaluated gross energy savings over the evaluation period. Refrigerators accounted for 20 per cent of the rebated appliances and 12 per cent of the offer's overall gross savings.

2. The variance between evaluated and reported gross savings was due mainly to differences in the unit energy savings calculated for clothes washers. Evaluated unit savings for clothes washers were higher than reported as a result of including additional savings in clothes drying associated with high efficiency clothes washers.

3. Evaluated free ridership, from the perspective of customers who received an appliance rebate, was higher than that assumed in reported savings (71 to 76 per cent as compared to 11 to 20 per cent, respectively) and evaluated participant spillover was lower than that assumed in reported (1 per cent as compared to 10 to 25 per cent, respectively).

4. It is reasonable to believe that the program induced incremental sales of high efficiency appliances by influencing retailer product stocking and sales practices (i.e., market effects) and by influencing consumers who saw the program's advertising or were aware of the rebate but did not apply for one (i.e., non-participant spillover). However, any savings through these streams were not

captured in this evaluation as the data available did not permit the development of a valid attribution score or an estimate of non-participant spillover.

5. Evaluated net savings for appliances are not reported for this evaluation due to the incomplete information about program influence on non-participants and retailers, and the indirect influence on appliance purchasers. The rationale for this decision is that it would be inappropriate to apply the free rider scores without understanding and accounting for other influences, beyond the rebate, on purchaser decision-making.

Recommendations

Recommendations 1 to 4 are for program management. Recommendation 5 is for Evaluation and Recommendations 6 and 7 are for both. The recommendations are not presented in any order of priority.

1. Explore why the speed of receiving their appliance rebates is considered less than satisfactory by a portion of applicants and how the issuance of rebates could be accelerated to improve customer ratings.
2. Continue to collect comprehensive sales data from retail partners for tracking and evaluating market trends and assessing program impacts of retail programs.
3. If clothes washers continue to be included in the appliance rebate offer, update the calculation of reported clothes washer savings to incorporate savings in clothes drying.
4. Consider options to modify the program offers or target markets to reduce free ridership.
5. For offers featuring an incentive paid to retailers, examine program influence on retailers in greater depth to better understand and account for market effects and associated energy savings.

6. Evaluation and Marketing should consider collecting additional data to enable the evaluation of non-participant spillover and market effects from the appliance offer in the future.
7. Consider the feasibility of evaluating advertising-only initiatives (like TV recycling) and how to collect the necessary data for any subsequent evaluation.

6.5 Conclusions

Evaluated savings for the Consumer Electronics offer were lower than reported, mainly due to the convergence of the energy consumption of program qualifying televisions and the television market overall. The set-top box component of the program was successful in transforming the products of a major service provider partner.

Evaluated gross savings for the appliances rebate were almost double the reported savings as a result of including savings from clothes drying. The evaluation did not estimate net savings for the Appliances Rebate offer as the effects of the program on retail partner behaviours or additional savings due to non-participant spillover and market effects were not adequately captured.

Glossary

ANCOVA: is a general linear model which blends ANOVA and regression to test the main and interaction effects of categorical variables on a continuous dependent variable, controlling for the effects of selected other continuous variables, which co-vary with the dependent.

Baseline: A baseline is the initial condition occurring when a DSM activity begins. It may be a market share for equipment, a current standard, or a current average behavior.

BC Hydro Service Area: The portion of the Province of B.C. that receives retail electricity service from BC Hydro. The service area excludes the portion of the Province of B.C. served by Aquila Networks Canada (previously known as West Kootenay Power and Utilicorp Networks Canada), FortisBC, and certain factories or communities that are not customers of BC Hydro. Approximately 75 per cent to 80 per cent of B.C.'s demand for electricity is in the BC Hydro service area and is supplied by BC Hydro.

Cross Effects: Cross effects (also known as interactive effects) refer to the effect that some energy conservation measures (**ECMs**) have on other electricity end uses beyond what the ECM itself produces. An obvious example is building lighting. As more efficient lighting is installed, less heat is generated by the lighting system. This means that less heat must be removed from the building by the air conditioning system during the cooling season, but more heat needs to be supplied by the heating system during the heating season.

Demand Side Management (DSM): The definition of Demand Side Management is the same as the definition of "demand-side measures" set out in section 1 of the *Clean Energy Act*, which is "a rate, measure, action or program undertaken; (a) to conserve energy or promote energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demand, but does not include (d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or (e) any rate, measure, action or program prescribed”.

End Use: The final application or final use to which energy is applied. Recognition of the fact that electric energy is of no value to a user without first being transformed by a piece of equipment into a service of economic value. For example, office lighting is an end use, whereas electricity sold to the office tenant is of no value without the equipment (light fixtures, wiring, etc.) needed to convert the electricity into visible light. End use is often used interchangeably with energy service.

ENERGY STAR®: ENERGY STAR® is the mark of high-efficiency products in Canada that meet strict technical specifications for energy performance—tested and certified. These products save energy without compromising performance in any way. Typically, an ENERGY STAR® certified product is in the top 15 to 30 per cent of its class for energy performance.

Expected Savings: Estimate of gross energy savings based on customer initially reported savings, engineering review and site inspection. These estimates represent the unverified savings.

Free Riders: Free riders are program participants who would have taken the DSM action, even in the absence of the DSM program. They are a part of the reference case. These actions are not attributable to the program.

Gigawatt Hour (GWh): One billion watt-hours; one million kilowatt hours.

Gross Savings : The change in energy consumption and/or associated demand that results directly from program-related action taken by the participants in the demand side management program irrespective of why they participated.

Market Transformation: Market Transformation refers to a permanent change in the structure or functioning of markets, including more energy-efficient behaviour among customers and higher market penetration of energy-efficient products, as a result of

DSM programs that reduce barriers to energy efficiency. These market changes are likely to persist in the absence of continued program activity.

Mid-stream/upstream: The term mid-stream is used in reference to the part of the supply chain that is closer to the customer, such as retailers or contractors. The term up-stream can be used in two ways: 1) to refer to the manufacturers of products or, 2) more generically, to indicate suppliers to the purchasers.

Net savings: The change in energy consumption and/or associated demand that is attributable to the utility DSM program. The change in consumption or associated demand may include the effects of free riders and spillover.

Net-to-gross ratio: A factor representing net demand side management program savings divided by gross program savings that is applied to gross program impacts to convert them into net program load impacts. The factor is made-up of a variety of factors that create differences between gross and net savings, commonly including free riders and spillover. Other adjustments may include rebound, cross effects and measurement and verification results.

Non-energy benefits: Benefits that accrue to program participants (e.g., increased property values, decreased water and sewer bills, increased comfort, health and safety), to the utility (e.g., bill payment improvements, decreased service calls), or to society in general (e.g., improved environmental health, job creation).

Peak Demand - Demand refers to the amount of electricity that is consumed at any instant in time, measured in multiples of watts. Peak demand savings are the reduction in amount of electricity that is consumed at system peak demand, which for BC Hydro occurs on a winter weekday between approximately 5 p.m. and 7 p.m.

Persistence: Refers to how long the energy savings are expected to be attributable to the demand side management activity.

Precision: The degree to which repeated measurements under unchanged conditions show the same results.

Quasi-Experimental Design: is an empirical study used to estimate the causal impact of an intervention on its target population. Quasi-experimental research shares similarities with the traditional experimental design or randomized controlled trial, but they specifically lack the element of random assignment to treatment or control. Instead, quasi-experimental designs typically allow the researcher to control the assignment to the treatment condition, but using some criterion other than random assignment. A well designed Quasi-Experiment can control on key factors when a randomized controlled trial is not practical.

Realization Rate: The ratio of initial estimates of savings to savings adjusted for data errors and measurement and verification results. Does not reflect program attribution or influence on the savings achieved.

Reported Savings: Estimate of energy savings being recorded in the program tracking database. Reported savings are based on best information available from technical review of the initial engineering estimate, post implementation review of documentation and/or inspection, or measurement and verification results, as well as, a forecast net-to-gross ratio applied.

Spillover: Refers to program participants and non-participants whose energy savings measures occur through actions that are not part of a program, but which were influenced by the program (also called free drivers or tag-ons). Participant spillover is the additional energy savings that occur when a program participant independently installs energy efficiency measures or applies energy savings practices after having participated in the efficiency program, as a result of the program's influence. Non-participant spillover refers to energy savings that occur when a program non-participant installs energy efficiency measures or applies energy savings practices as a result of a program's influence. Spillover is expressed as a fraction of the increase of energy savings due to spillover to the gross energy savings of the program participant. Spillover may not be permanent and may not continue in the absence of continued program activity.

Evaluation of the Residential Inclining Block Rate

F2013-F2017

April 2018

Prepared by: Conservation and Energy Management Evaluation

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Executive Summary

Introduction

The Residential Inclining Block (RIB) rate is a two-step rate structure where BC Hydro's residential customers pay a lower price for electricity consumption up to a certain threshold, and a higher price for electricity consumption beyond the threshold.

The RIB rate went into effect in October 2008 for approximately 1.6 million residential customers. The Step 1 to Step 2 threshold was set at 1,350 kWh per two-month billing period, which was approximately 90 percent of the median consumption of BC Hydro's residential customers. The Step 2 rate was established at BC Hydro's current estimate of the cost of new energy supply, grossed up for losses, and the Step 1 rate was calculated to achieve revenue neutrality for the residential class. The over-arching objective of the RIB rate was to use price to encourage additional electricity conservation relative to what was achievable through a flat rate structure.

The last evaluation of the RIB rate was conducted in 2013[1] and evaluated the price elasticity of consumption and the electricity conservation impacts in response to the rate's two-step structure, as well as customer awareness, understanding, and response to the RIB rate for the period from October 2008 through March 2012 (the mid-point of F2009 through F2012). This evaluation is a continuation of the 2013 evaluation, and covers April 2012 through March 2017 (F2013-F2017).

Approach

The evaluation objectives and research questions are shown on the following page.

[1] BC Hydro (2014) "Evaluation of the Residential Inclining Block Rate F2009-F2012", Revision 2, Power Smart Evaluation, BC Hydro.

Table E.1: Evaluation Objectives and Research Questions

Objectives	Research Questions
1. Estimate Price Elasticity	• What is the price elasticity of Step 1 and Step 2 consumption? • Is there a difference in price elasticity between BCH customers and a comparable community without a RIB rate (e.g. New Westminster)? • What is the price elasticity due to natural conservation, as measured by the price response to general rate increases through F2017? • How do the results of research questions related to price elasticity compare to previous research on this topic conducted as part of the last RIB rate evaluation?
2. Estimate the Conservation Impacts of the RIB Rate	• What are the energy savings due to BC Hydro's RIB Rate from F2013 to F2017? • What are the peak demand savings due to BC Hydro's RIB rate from F2013 to F2017? • What are the energy savings due to natural conservation from F2013 to F2017, as measured by the price response to general rate increases?
3. Analyze Differences in Price Elasticity by Customer Characteristics	• Are there differences in price elasticity by region? • Are there differences in price elasticity by dwelling type? • Are there differences in price elasticity by space heating type? • How do the results of research questions related to price elasticity compare to previous research on this topic conducted as part of the last RIB rate evaluation? • Are there differences in price elasticity between winter and summer periods?
4. Evaluate the Customer Response and Understanding of the RIB Rate	• Are there differences in the characteristics or demographics of customers who are never billed in Step 2 compared to those who are sometimes or always billed in Step 2? • What is the level of customer awareness and understanding of the RIB rate? • To what degree do customers believe electricity prices provide an incentive to manage electricity consumption? • To what extent do customers believe the total electricity bill amount provides an incentive to manage electricity consumption? • What is customers' understanding of their prevailing electricity price under the RIB rate structure? • To what extent do customers believe the RIB provides an incentive to manage electricity consumption? • To what extent do RIB aware customers report energy conserving behaviours as compared to non-RIB aware customers? • To what extent do RIB aware customers report implementing longer term capital investment in energy efficiency or conservation as compared to non-RIB aware customers? • Was program participation in DSM programs different between customers aware / not aware of the RIB rate? • Did low income customers have a different perception or response to the RIB Rate? • Does the RIB rate have any impact on customers' decisions on fuel switching from electricity to thermal fuels? • Is the RIB rate perceived as a barrier to electrification? • Has customers' response/acceptance to RIB changed over time? • Do customers support the RIB rate? • Do notifications / alerts on Step 2 have an impact on customers' consumption behaviour? • How do the results of research questions related to customer response and understanding of the RIB rate compare to previous research on this topic completed as part of the last RIB rate evaluation or REUS surveys?

The table below summarizes the data sources and methods employed in this study for each evaluation objective.

Table E.2: Summary of Evaluation Objectives, Data Sources and Methods

Evaluation Objective	Data Sources	Methods
1. Estimate Price Elasticity	• BC Hydro billing data from April 2004 to December 2016, including electricity consumption, space heating fuel, region and dwelling type by account • BC Hydro residential rate prices from April 2004 to December 2016 • BC Hydro DSM expenditures and savings, from 2004 to 2017 • BC Consumer Price Index data from April 2004 to December 2016 obtained from Statistics Canada • BC real disposable income from April 2004 to December 2016 from BC Stats • Heating and cooling degree days by region from April 2004 to December 2016 • New Westminster customer billing data from 2005 to 2016 and customer information on heating fuel and dwelling type	• Econometric modelling of price elasticity
2. Estimate the Conservation Impacts of the RIB Rate	• Data and results from Objective 1 • BC Hydro residential rate class load shape	• Calculation based on price elasticity and rate class load shape
3. Analyze Differences in Price Elasticity by Customer Characteristics	• Same as Objective 1	• Same as Objective 1
4. Evaluate the Customer Response and Understanding of the RIB Rate	• 2012 customer survey (n = 2,468) • 2017 customer survey (n = 3,307) • 2014 Residential End-Use Study (n=7,318) • 2017 Residential End-Use Study (n=6,929) • BC Hydro billing data from F2012 and F2017 • Data on customer sign-ups for Step 2 alerts • BC Hydro residential DSM program tracking data	• Cross tabulations of survey responses • Linking of survey responses to respondent billing history • Difference in proportions z-tests • Difference of Means Tests using Analysis of Variance

Objective 1, estimating price elasticity, and Objective 3, analyzing elasticities differences by customer characteristics, were addressed through econometric modeling which utilized a variety of data sources including electricity consumption and Statistics Canada data. Objective 2 was a calculation using the results from Objective 1.

Objective 4, related to evaluating customer response and understanding of the RIB rate, was largely addressed through analysis and comparison of the results from two similar residential customer surveys which were delivered in 2012 and 2017.

Results

Price Elasticity

Step 1 consumption represents the consumption of those customers whose bi-monthly usage does not exceed the 1,350 kWh threshold. The Step 1 price elasticity of these customers was estimated to be -0.14. The previous RIB evaluation in 2013 was unable to detect a Step 1 price elasticity over the F2009 to F2012 period, nor did a subsequent analysis over the F2009 to F2015 period. Due to the fact that Step 1 price elasticity could not be detected for the F2009 to F2015 period, the estimate of -0.14 was only seen to be applicable to F2016 and F2017.

Step 2 consumption represents the consumption of those customers whose bi-monthly usage exceeds the 1,350 kWh threshold. The Step 2 price elasticity of these customers was estimated to be -0.08, which is at the low end of the range estimate of -0.08 to -0.13 from the 2013 evaluation. The current estimate indicates that in comparison to the earlier years of the RIB rate, customers who were exposed to Step 2 prices in recent years may have become less price responsive—measured by percentage change in consumption—to Step 2 price increases. It also indicates that their capacity and options to conserve energy while facing price increases may have been more limited in recent years. Meanwhile, Step 1 consumption has become price sensitive in recent years.

Table E.3: Step 1 and Step 2 Price Elasticity Estimates

Time Series Analyzed	Step 1 Elasticity	Step 2 Elasticity
F2005-F2012	Not statistically significant	-0.08 to -0.13***[2]
F2005-F2015[3]	Not statistically significant	Not analyzed
F2005-F2017	-0.14***	-0.08***

*** indicates statistically significant at 95% confidence level

The price elasticity of electricity consumption under a flat rate is used to calculate the natural conservation impact that would be achieved by general rate increases as per BC Hydro's approved Revenue Requirements. This flat rate price elasticity is used to estimate the baseline conservation that would have occurred in the absence of the RIB rate. The flat rate price elasticity could not be estimated through econometric analysis. A range estimate between the Step 1 and Step 2 elasticities was adopted (-0.08 to -0.14) to calculate the natural conservation impact. Since the Step 1 price elasticity estimate of -0.14 was only applicable to F2016 and F2017, the range estimate of the flat rate elasticity was similarly applied to F2016 and F2017 only. In the absence of an empirical estimate of flat rate elasticity in the F2013 to F2015 period, the planning assumption of -0.05[4] was applied to those years.

Conservation Impacts of the RIB Rate

In order to evaluate additional energy conservation achieved under the RIB rate relative to the flat rate, the energy impacts of the Step 1, Step 2, and the flat rate price response were calculated separately. The baseline scenario was considered natural conservation achieved under the flat rate due to general rate increases and the RIB rate structural savings were calculated as the sum of the Step 1 and Step 2 energy impact, less the natural conservation impact. The annual incremental structural savings from the RIB rate between F2013 and F2015 are presented below. The calculations are based on the value of Step 1 elasticity (zero), Step 2 elasticity (-0.08) and assumed flat rate elasticity (-0.05).

[2] BC Hydro (2014)
[3] In 2016, an analysis was conducted to evaluate the Step 1 price elasticity for the period of F2005-F2015. This analysis did not produce statistically significant results. The modelling outputs from this analysis were included in Appendix D.
[4] Orans, R (2008), the source and reasons for adopting this assumption were provided in the expert testimony of the 2008 BC Hydro Long-Term Acquisition Plan, Appendix E.

Table E.4: RIB Rate Savings F2013-F2015

Fiscal Year	Step 1 Price Impact (GWh)	Step 2 Price Impact (GWh)	Natural Conservation (GWh)	RIB Structural Savings (GWh)
	A	B	C	(A + B - C)
Elasticity	**0.00**	**-0.08**	**-0.05**	**-**
F2013	-	49	24	23
F2014	-	16	13	3
F2015	-	74	62	13

Given the potential range in flat rate elasticity (-0.08 to -0.14; assuming that it lies between the estimates of Step 1 and Step 2 elasticity), natural conservation and RIB structural savings in F2016 and F2017 could not be estimated with precision. Table E.5 shows the calculation of natural conservation and RIB structural savings using four different flat rate elasticities: -0.08, -0.09, -0.10 and -0.14. Based on this calculation, savings appear to decrease as flat rate elasticity increases. Based on the results derived through the range estimate, the evaluated RIB energy savings in F2016 and F2017 were deemed to be small or zero, as shown in table E.6 below.

Table E.5: RIB Rate Savings F2016-F2017

	Step 1 Price Impact (GWh)	Step 2 Price Impact (GWh)	Natural Conservation (GWh)				RIB Structural Savings (GWh)			
	A	B	C				(A + B- C)			
Elasticity	**-0.14**	**-0.08**	**-0.08**	**-0.09**	**-0.10**	**-0.14**	**-0.08**	**-0.09**	**-0.10**	**-0.14**
F2016	26	45	60	67	75	104	11	4	(3)	(33)
F2017	13	23	29	33	37	52	6	2	(2)	(16)

Based on the estimates of Step 1 (-0.14), Step 2 (-0.08), and the adopted flat rate elasticity range (-0.08 to -0.014) , the energy and peak demand saving impacts attributed to the RIB rate were calculated as presented in the table below.

Table E.6: Reported and Evaluated RIB Rate Savings

	Energy Savings (GWh)		Peak Demand Savings (MW)	
Fiscal Year	Reported	Evaluated	Reported	Evaluated
F2013	42	23	9	5
F2014	19	3	4	1
F2015	59	13	12	3
F2016	29	0 to 11	6	0 to 2
F2017	8	0 to 6	2	0 to 1

Two major factors contribute to the variance between reported and evaluated RIB rate savings. First, the Step 2 price elasticity of -0.08 was smaller (in absolute value) than the planning assumption of -0.1. Second, the flat rate elasticity range estimate applied to F2016 and F2017 was higher (in absolute value) than the value used in the forecast of RIB savings (-0.05).

Price Elasticity by Customer Characteristics

Additional analyses were conducted to determine if separate price elasticity estimates could be identified based on season or specific customer characteristics such as region, dwelling type, and space heating fuel. Those results are presented in Table E.7, where each category (region, dwelling type, space heating, winter vs summer) shows the results of a separate regression analysis. The results included in Table E.7 show that Step 1 and Step 2 price elasticity varied by region, dwelling type, space heating type and winter versus summer. In some instances, the elasticity estimate was not statistically significant.

Table E.7: Step 1 and Step 2 Price Elasticity by Customer Characteristics

Customer Segment	Step 1 Elasticity	Step 2 Elasticity
Region		
Lower Mainland	-0.22***	Not statistically significant
Vancouver Island	-0.18***	-0.12***
Southern Interior	Not statistically significant	Not statistically significant
North	-0.23***	Not statistically significant
Dwelling Type		
Single Family Dwelling	-0.04***	-0.08***
Row/Townhouse	-0.14***	-0.10***
Apartment	-0.26***	-0.07***
Mobile Home	-0.12***	-0.09***
Space Heating		
Electric	-0.11***	Not statistically significant
Non-Electric	-0.18***	-0.17***
Winter vs. Summer	Not statistically significant	More negative by 0.05 in winter than in summer (e.g. if summer price elasticity is -0.07, winter is -0.12)

*** indicates statistically significant at 95% confidence level

Customer Response and Understanding of the RIB Rate

Between F2013 and F2017, the proportion of customer households that never incurred Step 2 electricity consumption remained generally unchanged at approximately 30 percent. However, the proportion that sometimes incurred Step 2 consumption (1-11 months) increased from 39 percent to 48 percent while the proportion that always incurred Step 2 consumption (12 months) decreased from 30 percent to 22 percent.

Between 2012 and 2017, there was an increase from 53 percent to 64 percent in the proportion of customers who believed that BC Hydro's residential electricity prices were too high. In fact, for customers that never incurred electricity consumption beyond Step 1, there was no longer a majority in 2017 – as there was in 2012 – who felt that prices were 'about right'. The largest segment of these customers now believed prices were too high.

At 49 percent in 2012 and 47 percent in 2017, there has been no meaningful change over the past five years in the proportion of customer respondents who knew that BC Hydro charges their consumption of electricity on an inclining block rate. For these particular customers, they believed that their total bill amounts serve as the greatest incentive to manage their consumption of electricity, followed by electricity prices and then followed by the rate structure. In fact, the RIB rate structure was seen as less of an incentive in 2017 than it was in 2012.

In the 2017 survey, customers previously aware of the RIB rate were more likely than others to have completed a home energy efficiency upgrade in the previous three years, to have participated in at least one of BC Hydro's conservation programs, and to have outperformed other customers on many in-home conservation behaviours. However, it could not be ascertained through the research if and to what extent awareness of the rate structure led to the decisions to engage in these activities.

Customer support of BC Hydro's RIB rate decreased from 59 percent to 55 percent between 2012 and 2017. Support continues to measure highest among customers who never incur Step 2 electricity consumption in a fiscal year.

Findings

Price Elasticity

1. The overall average Step 1 price elasticity was estimated to be -0.14 for F2016 and F2017. Previous analyses, covering the time period of F2005-F2012 and F2005- F2015, were unable to detect Step 1 price elasticity, likely due to relatively low Step 1 prices and small changes in the Step 1 price in earlier years. As a result, Step 1 price elasticity was assumed to be zero in the calculation of energy savings for F2013 to F2015, which was the same approach used in the 2013 Evaluation.

2. Step 2 price elasticity was estimated at -0.08, which is at the low end of the range from the previous evaluation (-0.08 to -0.13). This result may suggest that customer response to the Step 2 price has diminished over time.

3. A range of -0.08 to -0.14 was adopted to estimate natural conservation due to general rate increases under a flat rate in F2016 and F2017. This range spans the empirical estimates for Step 1 and Step 2 price elasticity for F2016 and F2017. In the absence of empirical estimates of flat rate and Step 1 price elasticities in the F2013-F2015 period, the planning assumption of -0.05 was applied for natural conservation in those years.

4. To obtain a proxy estimate of the flat rate elasticity, an analysis of residential consumption data from F2005 to F2016 in New Westminster, a jurisdiction serviced under a flat rate, was conducted. However, it did not produce a statistically significant estimate of flat rate elasticity.

Conservation Impacts of the RIB Rate

5. The annual incremental structural savings from the RIB rate were evaluated at 23 GWh, 3 GWh, and 13 GWh between F2013 and F2015.

6. Given the range of estimated flat rate elasticity due to general rate increases, (-0.08 to -0.14), definitive results for natural conservation and RIB structural savings in F2016 and F2017 could not be determined. Calculated RIB structural savings in F2016 and F2017 decreased as the flat rate elasticity increased. As a result, RIB structural savings in F2016 and F2017 were deemed to be small or zero.

Differences in Price Elasticity by Customer Characteristics

7. Price elasticity by region: Step 1 price elasticity was detected in three out of four geographic regions compared to none in the previous evaluation[5]. Step 2 price elasticity was detected in one region compared to all four regions in the previous evaluation. These results indicate that the Step 2 price is no longer a strong factor in determining electricity consumption in a large part of BC Hydro's service area.

8. Price elasticity by dwelling type: Step 1 price elasticity was identified in four dwelling types compared to none in the previous evaluation. Relative to the previous evaluation, Step 2 price elasticity decreased among single family dwellings and increased among row or townhouses and apartments.

9. Price elasticity by space heating type: Step 1 price elasticity was detected in households with electric and non-electric primary space heating, contrary to the previous evaluation. Step 2 price elasticity was only detected in households with non-electric primary space heating, and at a lower level than in the previous evaluation. The previous evaluation detected Step 2 price elasticity in both types of households. This finding suggests that energy savings induced by price changes from F2013 forward may have come from sources other than electric space heating.

[5] BC Hydro (2014)

10. Price elasticity in winter vs. summer: The analysis found no statistically significant difference in Step 1 price elasticity between winter and summer and a difference of -0.05 in Step 2 price elasticity—with elasticity being more negative in winter than in summer. This result indicates that for Step 2 consumption, the price sensitivity and price impact are greater in winter than in summer.

Customer Response, Awareness, and Understanding

11. From F2013 through to F2017, the proportion of customer households that incurred at least some Step 2 electricity consumption remained generally even at 70 percent. Through these five years, however, there was a decrease from 30 percent to 22 percent in the proportion that were into Step 2 in each month of a fiscal year.

12. Between 2012 and 2017, there was an increase from 53 percent to 64 percent in the proportion of customers who felt that BC Hydro's residential electricity prices were too high. Furthermore, the extent that customers felt this way was highly correlated with their exposure to Step 2 electricity consumption.

13. For customers that never incurred electricity consumption beyond Step 1, there was no longer a majority in 2017 – as there was in 2012 – who felt that prices were 'about right'. The largest segment of these customers now believed prices were too high. Their beliefs around the price of electricity in each of the 2012 and 2017 surveys help to explain why a Step 1 price elasticity was not detected until F2016 and F2017 as customers became increasingly responsive to increases in the Step 1 price.

14. Customers' unaided awareness that BC Hydro charges household consumption of electricity on an inclining block rate has gone generally unchanged over the past five years, measuring 49 percent in 2012 and 47 percent in 2017.

15. For customers previously aware of the RIB rate in each of the 2012 and 2017 surveys, their total bill amounts emerged as serving more of an incentive to manage their consumption of electricity than did electricity prices or the rate structure. In fact, the inclining block rate was considered to be less of an incentive in 2017 than it was in 2012, which is consistent with the findings regarding price elasticity and conservation.

16. Customers previously aware of the RIB rate in the 2017 survey were more likely than others to have completed a home energy efficiency upgrade in the previous three years, to have participated in at least one of BC Hydro's conservation programs, and to have outperformed them on many in-home conservation behaviours. However, it could not be ascertained through the research if and to what extent awareness of the rate structure led to the decisions to engage in these activities.

17. The total proportion of customers who support the RIB rate – including those who may have learned about it for the first time in the survey – has decreased from 59 percent to 55 percent over the past five years. Support continues to measure highest among customers who never incur Step 2 electricity consumption.

Recommendations

1. Consider whether the existing rate structure continues to serve BC Hydro's business objectives and meet customer needs, given that the current RIB rate structure appeared to yield little or no energy savings in F2016 and F2017.

2. Given the finding that larger consuming customers are more price responsive in the winter than in summer, consider exploring the value of a seasonal rate, with different pricing and consumption thresholds in the winter.

3. Consider the value of targeting small electricity consumers (e.g. those living in apartments) with existing or new DSM program offers, given their increased response to price changes in recent years.

Conclusions

Although awareness of the RIB rate has remained relatively unchanged over the past five years at just under 50 percent among all residential customers, the survey analysis has shown that a greater proportion of small customers now feel that electricity prices are too high and the econometric analysis has indicated that they have become more responsive to price changes.

Overall, the RIB rate appears to have achieved its objective of encouraging conservation through the customer response to higher marginal prices. However, the effectiveness of the RIB rate in yielding electricity savings appears to have diminished over time.

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1.0 Introduction

The Residential Inclining Block (RIB) rate is a two-step rate, where BC Hydro's residential customers who take electricity service under this rate pay a lower price for electricity consumption below a 1,350 kWh bi-monthly threshold and a higher price for electricity consumption above the kWh threshold.

1.1 Evaluation Scope

The previous evaluation of the RIB rate was conducted in 2013 and evaluated the price elasticity of consumption and the electricity conservation impacts in response to the rate's two-step structure, as well as customer awareness, understanding, and response to the RIB rate for the period October 2008 through March 2012 (the mid-point of F2009 through F2012). This evaluation is a continuation of the 2013 evaluation, and covers April 2012 through March 2017 (F2013-F2017).

1.2 Organization of Report

The organization of this report is as follows. Section 1 covers the evaluation scope, the organization of the report and the initiative description. Section 2 discusses the approach to the evaluation, including evaluation objectives, methodology review, data sources and methods. Section 3 provides the results organized by evaluation objective. Section 4 provides the findings and recommendations. Section 5 provides the conclusions. Additional supporting material is included in the appendices.

1.3 RIB Rate Overview

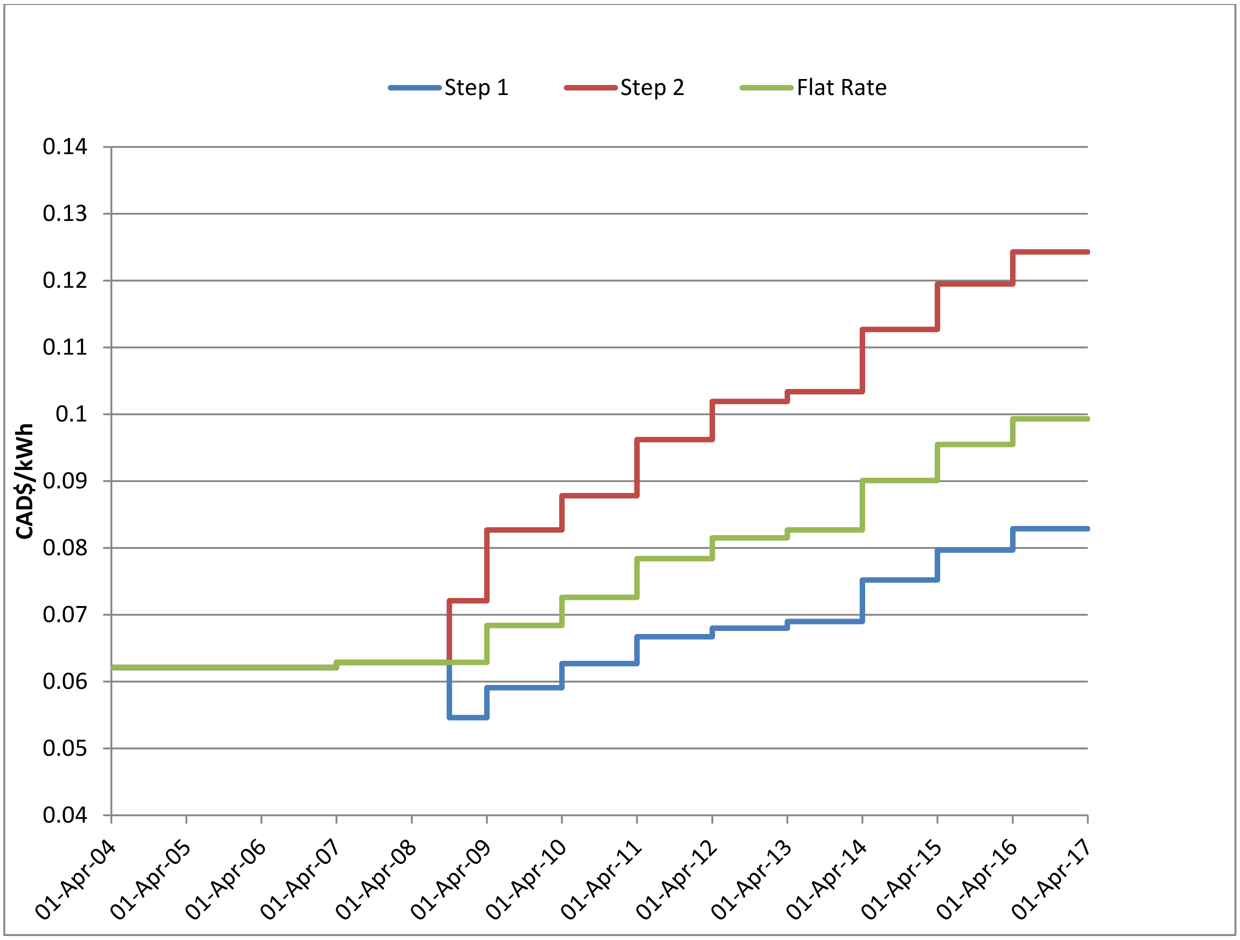
The use of conservation rate structures is one of three tools used in BC Hydro's Demand Side Management (DSM) Plan, the other two being energy efficiency programs and support for government codes and standards. The overarching objective of the RIB rate was to use price to encourage additional electricity conservation relative to what was achievable through a flat rate structure. This objective was supported by the inclining block rate design, where customers are billed at a lower (Step 1) rate for consumption below the 1,350 kWh threshold in a bi-monthly billing period, and at a higher (Step 2) rate for consumption above the threshold, thus setting a higher marginal price for large users relative to the flat rate they were billed at before the introduction of the RIB rate. Theoretically, the energy consumption of customers who rarely or never exceed the threshold may increase under this rate structure, since the Step 1 price was initially lower than the previous price. However, given that only approximately 20 percent of marginal consumption under the RIB rate was priced at Step 1, it was expected that any additional consumption by Step 1 customers would be offset and surpassed by the energy savings achieved by customers with Step 2 consumption, who were charged at a higher marginal price.

In August 2008 the British Columbia Utilities Commission (BCUC) determined that it was in the public interest for BC Hydro to implement the new RIB rate and required the new RIB rate structure to go into effect October 1, 2008 for approximately 1.6 million residential customers[6]. The Step 1 to Step 2 threshold was set at 1,350 kWh per bi-monthly billing period, approximately 90 percent of the median consumption of BC Hydro's residential customers. The 2 step price was gradually increased over time until it reached BC Hydro's estimated long run marginal cost of new energy supply. The Step 1 price was set residually to achieve revenue neutrality for the residential class.

[6] Certain residential groups were exempt from the RIB rate and continued to be charged under a flat rate, referred to as rate schedule 1151 in the BC Hydro tariff. The exempt group included farms and customers in the Bella Bella region.

Figure 1.1 below shows the nominal price changes in the RIB Step 1 and Step 2 prices, as well as the flat rate[7] that would have continued in the absence of the RIB, from F2005 through F2017.

Figure 1.1: RIB and Residential Flat Rate Energy Prices, F2005-F2017



The table below summarizes the energy prices charged to customers under the RIB rate between F2013 and F2017, and the ratio between step 2 and step 1 prices.

Table 0.1: Residential Inclining Block Rate Energy Prices between F2013 and F2017 (Nominal Dollars)

Price	F2013	F2014	F2015	F2016	F2017
Step 1 Price (¢/kWh)	6.8	6.9	7.52	7.97	8.29
Step 2 Price (¢/kWh)	10.19	10.34	11.27	11.95	12.43
Step 2 : Step 1 Ratio	1.5	1.5	1.5	1.5	1.5

Parallel Initiatives: The RIB rate operated in parallel to a number of residential DSM initiatives that were delivered to residential customers and may have had impacts on electricity consumption. These initiatives included energy efficiency programs and government codes and standards. The impact evaluation

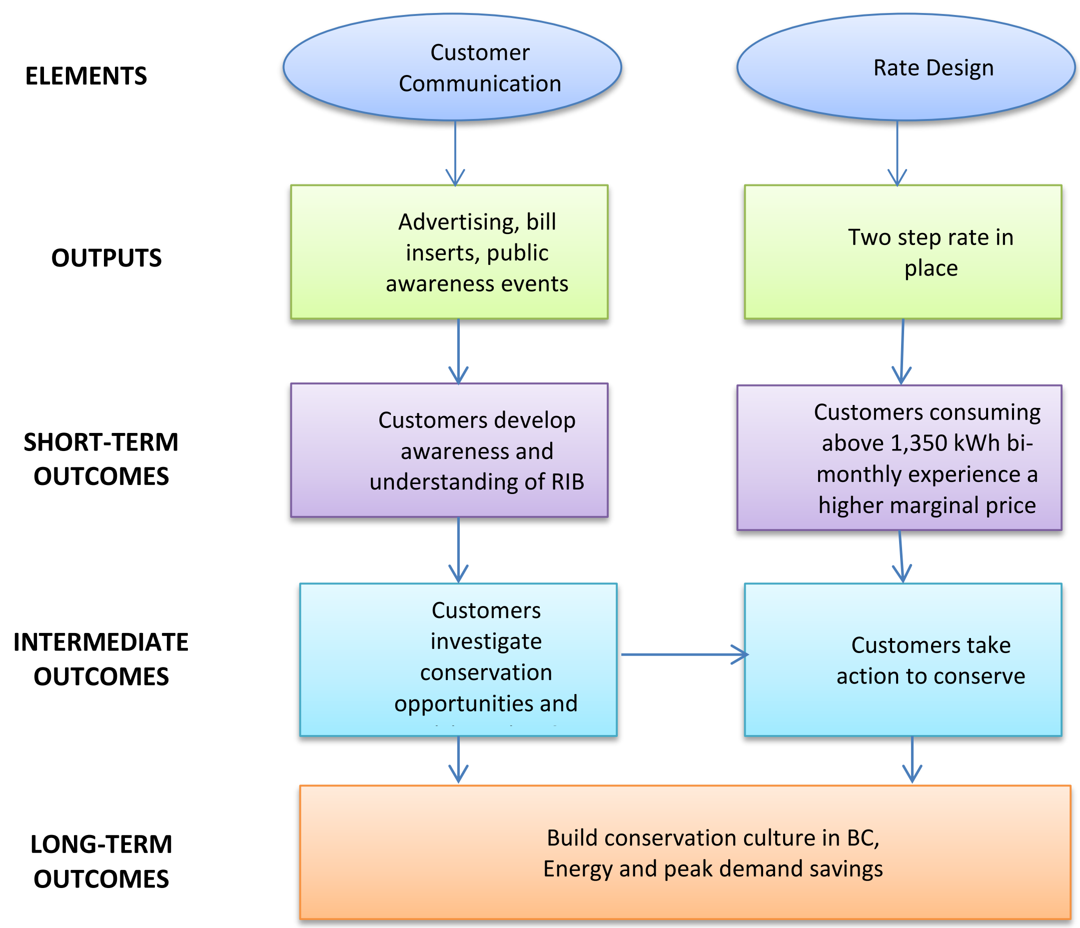
[7] The flat rate price changes included in Figure 1.1 refer to rate schedule 1151. The 1151 flat rate price was considered a proxy for what customers on the RIB rate would have been charged without the implementation of the RIB rate.

methodology used in this evaluation of the RIB accounted for the effect of these parallel DSM initiatives. Evaluated savings for the RIB do not include savings resulting from the parallel DSM initiatives mentioned above[8].

Program Logic Model: The RIB rate, through its price signals, was intended to encourage the adoption of conservation actions and encourage participation in BC Hydro's residential energy efficiency programs by improving the payback on conservation investments. Conversely, the presence of BC Hydro residential energy efficiency programs and educational initiatives was expected to elevate customers' awareness and understanding of the RIB rate, and enhance their response to the rate's price signals.

The logic model presented in Figure 1.2 illustrates how the RIB rate works toward energy conservation by dividing the initiative into its main elements or activities, and examining the logic chain for each element or activity.

Figure 1.2: RIB Logic Model



[8] The econometric analysis tests the sensitivity and influence of DSM programs and code and standard savings on the estimate of the RIB price elasticity and concludes that they do not affect the elasticity estimate. See Appendix D for the detailed econometric modelling results.

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2.0 Approach

2.1 Evaluation Objectives

The overall objective of this study is to evaluate the customer response to the RIB rate and to estimate energy and peak demand savings resulting from the rate. Table 2.1 summarizes BC Hydro's evaluation objectives and research questions to be addressed.

Table 2.1: Evaluation Objectives and Research Questions

Objectives	Research Questions
1. Estimate Price Elasticity	• What is the price elasticity of Step 1 and Step 2 consumption? • Is there a difference in price elasticity between BCH customers and a comparable community without a RIB rate (e.g. New Westminster)? • What is the price elasticity due to natural conservation, as measured by the price response to general rate increases through F2017? • How do the results of research questions related to price elasticity compare to previous research on this topic conducted as part of the last RIB rate evaluation?
2. Estimate the Conservation Impacts of the RIB Rate	• What are the energy savings due to BC Hydro's RIB Rate from F2013 to F2017? • What are the peak demand savings due to BC Hydro's RIB rate from F2013 to F2017? • What are the energy savings due to natural conservation from F2013 to F2017, as measured by the price response to general rate increases?
3. Analyze Differences in Price Elasticity by Customer Characteristics	• Are there differences in price elasticity by region? • Are there differences in price elasticity by dwelling type? • Are there differences in price elasticity by space heating type? • How do the results of research questions related to price elasticity compare to previous research on this topic conducted as part of the last RIB rate evaluation? • Are there differences in price elasticity between winter and summer periods?
4. Evaluate the Customer Response and Understanding of the RIB Rate	• Are there differences in the characteristics or demographics of customers who are never billed in Step 2 compared to those who are sometimes or always billed in Step 2? • What is the level of customer awareness and understanding of the RIB rate? • To what degree do customers believe electricity prices provide an incentive to manage electricity consumption? • To what extent do customers believe the total electricity bill amount provides an incentive to manage electricity consumption? • What is customers' understanding of their prevailing electricity price under the RIB rate structure? • To what extent do customers believe the RIB provides an incentive to manage electricity consumption? • To what extent do RIB aware customers report energy conserving behaviors as compared to non-RIB aware customers? • To what extent do RIB aware customers report implementing longer term capital investment in energy efficiency or conservation as compared to non-RIB aware customers? • Was program participation in DSM programs different between customers aware / not aware of the RIB rate? • Did low income customers have a different perception or response to the RIB Rate? • Does the RIB rate have any impact on customers' decisions on fuel switching from electricity to thermal fuels? • Is the RIB rate perceived as a barrier to electrification? • Has customers' response/acceptance to RIB changed over time? • Do customers support the RIB rate? • Do notifications / alerts on Step 2 have an impact on customers' consumption behavior? • How do the results of research questions related to customer response and understanding of the RIB rate compare to previous research on this topic completed as part of the last RIB rate evaluation or REUS surveys?

2.2 Methodology Review

A literature review of electricity rate studies in DSM evaluation resources and the academic literature shows that most evaluations have been focused on the estimation of price elasticity of various rate schemes and energy or demand impact by rate design. This methodology review briefly discusses the methodologies employed in the studies or evaluations of electricity rates and the learnings gleaned for the purpose of selecting a methodology for this RIB rate evaluation.

The methodologies for evaluating rate design vary in terms of evaluation methods and data construction. These methodologies are designed to address different evaluation questions and can be classified broadly into three types: 1) qualitative study through customer surveys to assess customers' perception, acceptance and behavioral responses to the rate design, 2) quantitative evaluation of rate impacts through estimation of price elasticity, and 3) experimental or quasi-experimental design to estimate the impacts of the different rate designs on electricity consumption.

The first type of methodology is designed to gauge customers' perception and response to electricity rate design. This type of evaluation is usually conducted through surveys of a representative sample of customers. This methodology is not widely used for rate evaluations due to customer privacy issues and evaluation budget constraints. For its conservation rate evaluation, FortisBC (2014) surveyed some customers with above average electricity consumption to assess their demographic information and energy uses. Sacramento Municipal Utility District (Potter J.M. et al., 2014) also conducted customer surveys to inform its SmartPricing evaluation and to assess customer's acceptance of potential changes to its pricing plan.

The second type of methodology involves quantitative study of rate impacts on electricity consumption. Such studies mainly entail econometric analysis to estimate price elasticity—the most commonly used measure in the electricity industry when analyzing consumption changes due to rate adjustments. It provides a straightforward and easy-to-compare means to measure the price impacts on electricity consumption and the magnitude of customers' price sensitivity. Many different techniques for econometric modelling of price elasticity have been developed to treat different research issues and/or address technical shortcomings. The methodology selected is often based on the specific market conditions and available data. Most elasticity studies adopt parametric models, which are based on economic and energy consumption theories. The following examples are the econometric studies of electricity price elasticity which use parametric models:

- Fullerton T. Jr et al. (2016) estimated both short-run and long-run residential price elasticity in El Paso, Texas for the period of 1977-2014,
- Ros (2015) estimated electricity price elasticity in the USA residential, commercial and industrial sectors,
- Sacramento Municipal Utility District (SMUD) in 2014 employed econometric models to estimate price elasticity for its SmartPricing evaluation, and
- Miller and Albernini (2016) provided a comprehensive review of elasticity analyses.

Other elasticity studies adopt non-parametric models which do not have a pre-defined model specification and provide an estimation of price elasticity based on a more flexible functional form. These models are often selected when estimates of price elasticity are thought to have changed over time[9].

The third type of methodology is experimental or quasi-experimental design. These methods rely on comparative analysis between a control group and a customer group that participated in a rate design. This method requires careful selection of the control or comparison group prior to the implementation of the rate

[9] Xiao et al. (2007) used non-parametric Bayesian model to estimate price elasticity of electricity demand and compared it to the results from parametric models.

design to ensure the comparability between the two groups. Faruqui et al. (2016) used a quasi-experimental design for an impact evaluation of a Time-of-Use rate in Ontario.

2.3 Methodology

The methodology adopted to evaluate the customer response to the RIB rate and the rate-induced conservation impacts has two parts. The first part is an estimation of the conservation impacts of the RIB rate via econometric modeling of price elasticity for each of the step 1 and step 2 price. Econometric models are selected as they provide a straightforward way to measure customers' price sensitivity and the resulting impacts on electricity consumption.

The second part evaluation method used surveys of a sample of RIB rate customers. A well designed survey with good sample coverage will provide accurate information on customers' perception and response to the RIB rate with high internal and external validity. The surveys also provide information or evidence that cannot be obtained from econometric analysis. The two methods are complementary and produce multiple lines of evidence and more valid and rich evaluation results.

Table 2.2 summarizes the data sources and methods employed in this study for each evaluation objective. Further description of the proposed methodology is provided in the subsequent sections, in order of evaluation objective. Alternative methodologies that were considered for this evaluation are presented in Section 2.4.

Table 2.2: Summary of Evaluation Objectives, Data Sources and Methodology

Evaluation Objective	Data Sources	Methods
1. Estimate Price Elasticity	• BC Hydro billing data from April 2004 to December 2016, including electricity consumption, space heating fuel, region and dwelling type by account • BC Hydro residential rate prices from April 2004 to December 2016 • BC Hydro DSM expenditures and savings, from 2004 to 2017 • Statistics Canada Consumer Price Index data from April 2004 to December 2016 • BC real disposable income from April 2004 to December 2016 from BC Stats • Heating and cooling degree days by region from April 2004 to December 2016 • New Westminster customer billing data from 2005 to 2016 and customer information on heating fuel and dwelling type	• Econometric modelling of price elasticity
2. Estimate the Conservation Impacts of the RIB Rate	• Data and results from Objective 1 • BC Hydro residential rate class load shape	• Calculation based on price elasticity and rate class load shape
3. Analyze Differences in Price Elasticity by Customer Characteristics	• Same as Objective 1	• Same as Objective 1
4. Evaluate the Customer Response and Understanding of the RIB Rate	• 2012 customer survey (n = 2,468) • 2017 customer survey (n = 3,307) • 2014 Residential End-Use Study (n=7,318) • 2017 Residential End-Use Study (n=6,929) • BC Hydro billing data from F2012 and F2017 • Data on customer sign-ups for Step 2 alerts • BC Hydro residential DSM program tracking data	• Cross tabulations of survey responses • Linking of survey responses to respondent billing history • Difference in proportions z-tests • Difference of Means Tests using Analysis of Variance

The methodology employed ultimately provides an estimate of evaluated net savings. Electricity cross effects and natural conservation are accounted for within the evaluated savings results. The method is not able to provide an estimate of the magnitude of electricity cross effects or the persistence of energy savings over time. Natural gas cross effects were not evaluated.

2.3.1 Methodology to Estimate Price Elasticity

Estimating conservation of the RIB rate first required estimates of price elasticity that measured customers' responsiveness to changes in price of their electricity. Step 1 and Step 2 price elasticity was estimated separately by modelling Step 1 and Step 2 consumption using linear regression analysis. The analysis quantified Step 1 and Step 2 consumption as the average bi-monthly consumption per account among groups of RIB customers defined by different dwelling types, geographical regions and heating fuel sources. The analysis was conducted at the aggregate level instead of using customer-specific data for a representative sample of customers, mainly because BC Hydro does not maintain detailed information at the individual account level on factors affecting electricity consumption, such as occupancy, personal income and residential building characteristics. Lack of detailed information pertaining to individual accounts could potentially lead to sample selection bias and the adopted approach of conducting the analysis at the aggregate level avoids such problems.

The following steps were employed to create the econometric models:

1. Determine the explanatory variables expected to influence electricity consumption and obtain applicable data;
2. Develop a basic functional form of the regression model;
3. Develop and test alternative forms of the regression model;
4. Estimate the price elasticity for Step 1 and Step 2 consumption;
5. Estimate the price elasticity for the baseline (flat rate) scenario.

These steps are further described below.

Step 1: Determine the Explanatory Variables Impacting Electricity Consumption and Obtain Data

Many factors influence electricity consumption. It is important to capture the major factors in the regression models in order to isolate the relationship between price and consumption. Factors considered as explanatory variables include electricity prices, weather, seasonality, space heating fuel, dwelling type, region, DSM expenditure and economic factors. As discussed later, various interactions between some of the variables were also considered. This is the same suite of explanatory variables that were tested in the 2014 RIB Evaluation, which provides high comparability of the elasticity results with those from the previous evaluation.

DSM initiatives, namely BC Hydro DSM programs and government codes and standards, and their impacts were also considered in the price elasticity models. BC Hydro DSM expenditures and the energy savings attributed to programs and codes and standards were the variables tested in the price elasticity models to examine whether price elasticity estimates were impacted. Alternative models with different treatment of the DSM expenditure or savings variables were tested in Step 3.

See Appendix C for further information on the methodology and each of the expected drivers of consumption.

Step 2: Develop the Basic Functional Form of the Regression Model

The overall goal was to create a simple and transparent model that reasonably explained the changes in electricity consumption with respect to changes in electricity price over the time period of analysis. The basic model postulates that electricity consumption is a function of electricity price, space heating fuel, dwelling type, geographic region, billing period, weather, and disposable income.

Equation 1 portrays the per account consumption regression estimated using the Ordinary Least Square method. This model represents the basic form of a double-log regression with the key explanatory variables expected to affect electricity consumption.

Equation 1

$$\ln(Consumption) = \alpha + \beta \cdot Heat + \gamma \cdot Dwelling + \delta \cdot BillingPeriod + \omega 1 \cdot CDD + \omega 2 \cdot HDD + \mathfrak{z} \cdot Region + \varepsilon \cdot ln\,(Price) + \sigma \cdot ln\,(Disposable\_Income) + \varphi \cdot C + \mu$$

Where,

ln() denotes natural logarithm; natural logarithm is used for convenience, because when it is used for both the consumption and price variables it results in a regression coefficient on the price variable that can be interpreted as an elasticity without additional calculation;

Consumption is average bimonthly electricity consumption per account in kWh;

Heat is a binary indicator (dummy variable) whose value is one to indicate the presence or zero to indicate absence of electricity as the primary space heating fuel;

Dwelling is a dummy variable to indicate different residential dwelling types: single family dwelling, apartment, row house, and mobile home;

BillingPeriod is a dummy variable that represents the six bimonthly billing periods in a calendar year to capture non-weather related seasonal effects;

CDD and *HDD* represent cooling and heating degree days, respectively, which are used to represent weather impacts;

Region is a dummy variable to represent the four regions in BC Hydro's service territory: Lower Mainland, Vancouver Island, Southern Interior, and North;

Price is the real electricity price charged to residential customers. It was a single flat rate before RIB and the applicable marginal rate in the RIB period. Price elasticity is represented by the coefficient (ε) for the price variable;

Disposable_Income: per capita real disposable income (CPI deflated);

C is a correction term to account for customer selection bias[10] caused by the fact that the Step 1 regression sample is made up of customers who only had Step 1 consumption in a given billing period and the Step 2 regression sample is made up of customers who had Step 2 consumption in a given billing period.

μ is the error term.

[10] See Heckman (1979) discusses sample selection bias and related specification error. See Havranek et al. (2012), Woo and Train (1988) and Yoo et al. (2007) for the examples of using the correction term to address sample selection bias.

Electricity consumption data was drawn from BC Hydro billing records for all RIB accounts from April 2004 to December 2016 (F2005 through Q3 of F2017). The analysis commenced in early 2017 when the complete data for F2017 was not yet available.

The electricity consumption data was set up in a panel format consisting of the four regions, four dwelling types, and two space heating fuel types described above. This produced a total of 32 observations per billing period and 2,400 observations for the entire period in the regression analysis. The first four and a half years of consumption was under the flat rate schedule and another eight and one quarter years was under the RIB rate.

Step 3: Develop and Test Alternative Forms of the Regression Model

Alternative forms of the basic model were constructed to test and compare the modeling results. The alternative forms explored the effect of adding or removing explanatory variables not included in the basic form. The estimate of price elasticity and the sensitivity of the estimate with respect to DSM initiatives were explored.

The impact of DSM expenditures and savings were tested in two alternative models.

Equation 2

$$\ln(Consumption) = \alpha + \beta \cdot Heat + \gamma \cdot Dwelling + \delta \cdot BillingPeriod + \omega 1 \cdot CDD + \omega 2 \cdot HDD + ʒ \cdot Region + \theta \cdot ln\left(DSM_{Expenditure}\right) + \varepsilon \cdot ln\,(Price) + \sigma \cdot ln\,(Disposable\_Income) + \varphi \cdot C + \mu$$

Where

$DSM_{Expenditure}$ is the real (CPI deflated) BC Hydro spending on DSM initiatives (programs, codes and standards, and sector enabling activities) in the residential sector.

Equation 3

$$\ln(Consumption + DSM\ Savings) = \alpha + \beta \cdot Heat + \gamma \cdot Dwelling + \delta \cdot BillingPeriod + \omega 1 \cdot CDD + \omega 2 \cdot HDD + ʒ \cdot Region + \varepsilon \cdot ln\,(Price) + \sigma \cdot ln\,(Disposable\_Income) + \varphi \cdot C + \mu$$

Where

DSM savings refer to electricity savings in BC generated by BC Hydro's DSM programs and government codes and standards in the residential sector.

The results of the models described in Equations 2 and 3 were compared to determine whether omitting a DSM variable would introduce meaningful error or bias to the estimates of price elasticity. As shown in Appendix D, the results indicated that reliable price elasticity estimates were obtained even in the absence of a DSM variable being included in the model.

Adding interaction terms to the regression model was also considered. For example, the relationship between weather and heating fuel is expected to have a strong influence on overall consumption since households with electric heat would have higher consumption in colder weather compared to households with non-electric heat. The alternative models explored the effects of including and/or excluding variables for:

- Billing period;
- Interactions between space heating fuel and weather; and
- Interactions between dwelling type and weather.

The selection of the alternative forms of the model was based on tested economic theories of drivers of residential electricity consumption and appropriate statistical and diagnostic tests. See Appendix C for additional details on the regression models and Appendix D for the full output of regression results.

Another model was developed to identify the difference in price elasticities between summer (June, July, August) and winter (November, December, January, February) as shown in Equation 4 on the following page. This model is similar to Equation 1 but only applies to monthly consumption data of the summer and winter months.

Equation 4

$$\ln(Consumption) = \alpha + \beta \cdot Heat + \gamma \cdot Dwelling + \delta \cdot BillingPeriod + \omega1 \cdot CDD + \omega2 \cdot HDD + \mathfrak{z} \cdot Region + \varepsilon \cdot \ln(Price) + \varepsilon1 \cdot Season \cdot \ln(Price) + \sigma \cdot ln\,(Disposable\_Income) + \varphi \cdot C + \mu$$

Where,

> *Season* is a dummy variable with value being either 1 to represent winter months or 0 to represent summer months.

An interaction term $Season \cdot ln\,(Price)$ was included in the model to detect any different price influence on consumption. Its coefficient, $\varepsilon1$, indicates any difference in price elasticity between the winter and summer months.

Steps 4: Estimate the Price Elasticity for Step 1 and Step 2 Consumption

To obtain separate Step 1 and Step 2 price elasticity estimates, RIB rate customers were separated into two groups in each billing period based on bi-monthly energy consumption. The threshold between Step 1 and Step 2 consumption is 1,350 kWh in a two-month period. All RIB rate customer accounts with consumption below 1,350 kWh in a given bi-monthly billing period were analyzed as the Step 1 group. All accounts with consumption above the 1,350 kWh threshold in a given bi-monthly billing period were separately analyzed as the Step 2 group. As such, individual customers may fall in either group in different billing periods, depending on their billed consumption for specific periods. Since the Step 1 regression sample only contains the aggregate consumption of "small" customers and the Step 2 regression sample only contains "large" customers in a given bi-monthly billing period, each of the two regression models contained a correction term (as shown in Equation 1) to correct for the sample selection bias of an individual account being included in the aggregate consumption of one group or the other. See Appendix C for additional details on the regression models and Appendix D for the output of regression results.

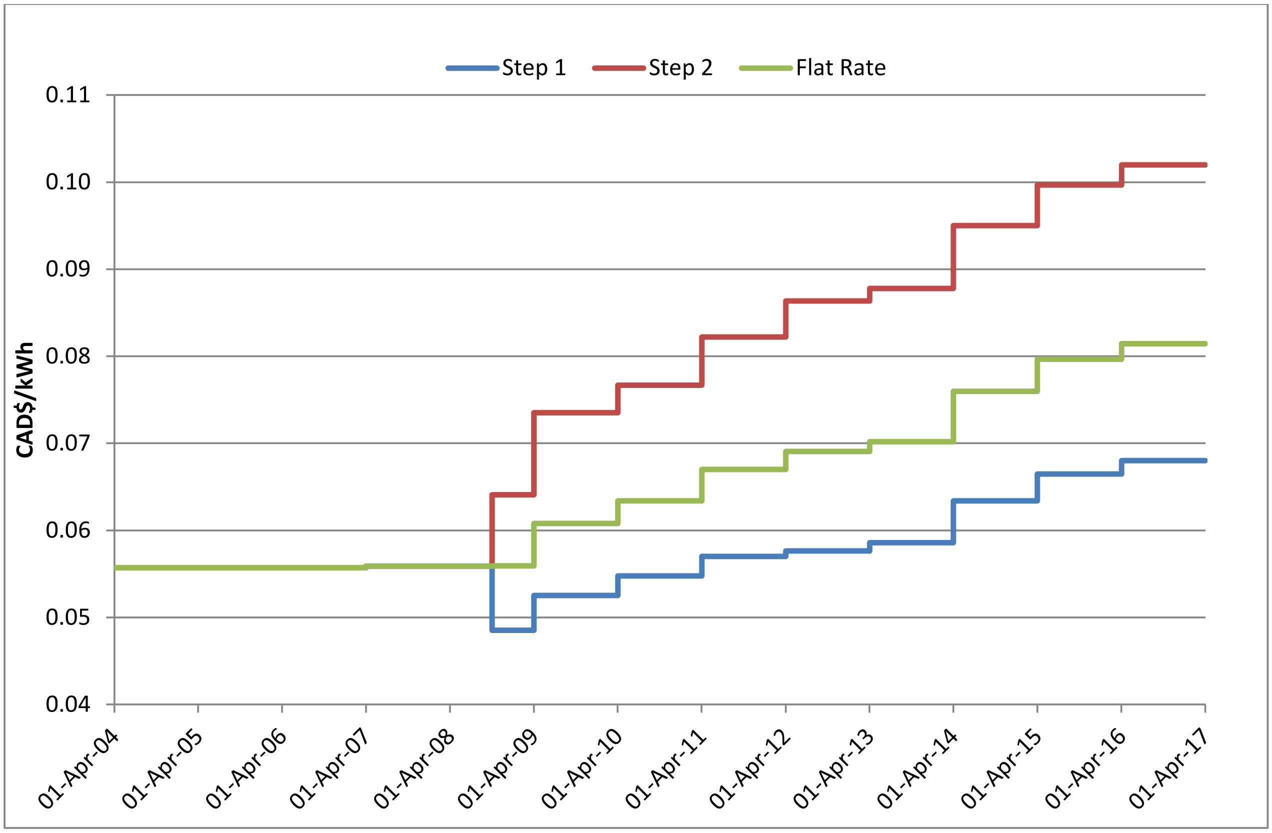
Step 5: Estimate the Price Elasticity for the Baseline Scenario

The baseline for estimating RIB rate savings was defined as a flat rate with general rate increases as per BC Hydro's approved Revenue Requirements Applications. Estimation of the price elasticity under a flat rate was required in order to estimate natural conservation due to general rate increases that would have occurred without the RIB rate structure.

BC Hydro's residential rate structure was switched from a flat rate to the RIB rate in October 2008. Since then, the flat rate has been applied only to specific customer groups under the 1151 Rate Schedule. The 1151 flat rate price was considered a proxy for what the customers on the RIB rate would have experienced without the implementation of the RIB from F2009 through F2017.

Figure 2.1 on the following page shows the real price changes after adjusting for inflation in Step 1, Step 2 and the flat rate from April 2004 (F2005) through to April 2017 (F2017).

Figure 2.1: Real Price Changes in the RIB and Residential Flat Rates after Inflation Adjustment (in 2002 dollar), F2005-F2017



The flat rate elasticity could not be empirically estimated. As a result, three options were considered for adopting a flat rate elasticity estimate. The first option was using the planning assumption of -0.05[11], which was adopted in the 2013 RIB rate application. The second option involved estimating flat rate elasticity by analyzing data from residents in New Westminster, which is another municipality in British Columbia. These customers were served by a different electric utility and charged under a flat rate. Any price elasticity estimated would then serve as a proxy for BC Hydro customers serviced under a flat rate. This analysis followed a method similar to that described in Step 1 through Step 3 above. The third option assumed that the flat rate elasticity falls somewhere in between the Step 1 and Step 2 price elasticities. This assumption was believed to be valid because the Step 1 and Step 2 price elasticity estimates are based on analysis of the same BC Hydro customers who would have been charged under a flat rate. In addition, the flat rate price falls within the range set by the Step 1 and Step 2 prices, and Step 1, Step 2 and the flat rate experienced the same annual price increases over the later part of the analysis period, as illustrated in Figure 2.1 above.

[11] Orans, R (2008), the source and reasons for adopting this assumption were provided in the expert testimony of the 2008 BC Hydro Long-Term Acquisition Plan.

2.3.2 Methodology to Estimate the Conservation Impacts of the RIB Rate

Energy and demand savings due to the RIB rate were calculated separately for Step 1 and Step 2 consumption, using the following steps, as described below:

1. Estimate total conservation for Step 1 and Step 2 consumption.
2. Estimate natural conservation under the baseline scenario.
3. Estimate structural conservation of the RIB rate as the difference between total and natural conservation.
4. Multiply total energy savings by a peak to energy ratio to estimate peak demand savings.

Step 1: Estimate Total Conservation

By definition, price elasticity multiplied by a percentage change in price yields the percentage change in consumption. The percentage change in consumption multiplied by the base year consumption gives the total change in consumption from the base year to the current year. For this evaluation, the percentage change in both Step 1 and Step 2 prices was defined as the percentage change in real price relative to the previous year. The method described in the 2008 RIB application[12] was designed to reflect estimated conservation over a phase-in period where the Step 2 rate was gradually increased, and it assumed that customer decisions were made relative to a price anchored in F2008. However, now that the RIB rate has been in place for more than nine years, it is reasonable to expect customers to adjust consumption based on the most recent price changes they experienced, rather than for example a price change relative to the flat rate that they were charged prior to the implementation of the RIB rate in 2008. This is the approach that was applied here, which is similar to what was done in the previous evaluation in 2013.

The impact of electricity consumption due to increases in each of Step 1 and Step 2 prices was calculated separately with the inputs of price elasticity and the previous year's consumption, as specified in the following equation:

Equation 5

$$\Delta\, kWh_t = \varepsilon_{price} \cdot \%\,\Delta price \;\cdot\; Electricity\ Consumption_{\,t-1}$$

Where:

$\Delta\, kWh_t$ is the consumption change (impact) in year *t* due to the change in price;

ε_{price} is the estimated price elasticity from the econometric models;

$\%\,\Delta price$ is the percentage change in real price relative to the previous year; and

$ElectricityConsumption_{t-1}$, for Step 1 impact, is the total consumption in the previous year from customer bills that do not exceed 1,350 kWh in any billing period. For Step 2 impact, it is the total consumption in the previous year from customer bills that exceed 1,350 kWh (including the first 1,350 kWh of electricity consumption per billing period billed at Step 1 price).

Total conservation is calculated as the sum of Step 1 and Step 2 impacts based on Equation 6:

[12] BC Hydro (2008) "Residential Inclining Block Application".

Equation 6

$$Total\ RIB\ Conservation\ Impact = \varepsilon_{Step\ 1\ price} \cdot \%\ \Delta Step\ 1\ price\ \cdot\ Step\ 1\ Electricity\ Consumption_{\ t-1} + \varepsilon_{Step\ 2\ price} \cdot \%\ \Delta Step\ 2\ price\ \cdot\ Step\ 2\ Electricity\ Consumption_{\ t-1}$$

Step 2: Estimate Natural Conservation

Calculations of natural conservation were based on Equation 5 with inputs of total (actual) residential sales charged at the RIB rate, the changes in the price for the 1151 Rate Schedule, and the flat rate elasticity.

Step 3: Estimate Structural Conservation

The natural conservation impacts were subtracted from the total conservation as a result of the RIB rate to arrive at the consumption impacts attributable to the structure of the RIB rate.

Equation 7

$$RIB\ Structure\ Impact = \ (Total\ RIB\ Conservation\ Impact - Natural\ Conservation\ Impact)$$

Step 4: Estimate Peak Demand Savings

Peak demand savings for the RIB rate were estimated by multiplying RIB structure energy impact, in GWh, by a peak-to-energy ratio based on the residential rate class load shape. This calculation assumes that RIB rate savings have the same shape as the total electricity consumption of the residential rate class.

2.3.3 Methodology for Analyzing Differences in Price Elasticity by Customer Characteristics

To further understand price responsiveness of different groups of customers, the data were partitioned by region, space heating fuel and dwelling type. The regression models (Equation 1) for Step 1 and Step 2 consumption used the different subsets of data to evaluate the price elasticity of different groups. The results for these models are presented in Section 3.

2.3.4 Methodology to Evaluate Customer Response and Understanding of the RIB Rate

Examination of the customer response and understanding of the RIB rate relied on customer survey data and billing data. RIB rate customer surveys were administered in January/February 2012 and in July/August 2017 to collect and track information on awareness, understanding and decision making related to the RIB rate, opinions on electricity pricing, behaviors around energy use, as well as additional demographic and housing parameters to inform the evaluation.

For the 2017 survey, a self-administered methodology – with online and print booklet options – was selected to afford respondents the time to formulate and express well considered responses to the number of complex questions being asked of them. Specifically, all randomly sampled customers were first mailed an invitation letter that served to introduce the study and to encourage their early participation in the survey by completing it online. Customers who had not completed the survey online by a specified date were then mailed a survey booklet with the option of either mailing it back in the business reply envelope, or completing it online. Lastly, customers who still had not completed the survey by a subsequent date were mailed a reminder card as a final attempt to promote participation.

The administration of the 2012 survey was very similar to that of the 2017 survey in that respondents had the two different ways of completing the survey. However, it did not utilize an initial invitation letter, and instead led directly with the survey booklet – with the option to complete online – followed by the reminder card.

The population of interest for both surveys was defined as the approximately 1.7 million customer households in BC Hydro's service territory with a residential account charged on the 1101 tariff, thereby excluding those residential in the non-integrated areas who are not charged under the RIB rate. Representative random samples of 10,000 customers were drawn from the overall population in BC Hydro's billing system with the survey correspondence subsequently sent to their households.

The 2017 survey's final sample was comprised of 3,307 customer respondents (1,792 online and 1,515 booklets) who not only completed the full survey, but also granted permission for their responses to be linked to their account history – a prerequisite for the survey analysis presented herein. This total translated to a 33 percent response rate and, at the 95 percent confidence level, a maximum margin of error of ± 1.7 percent.

The 2012 survey's final sample was comprised of 2,468 customer respondents (1,621 online and 857 booklets). This total translated to a 25 percent response rate and, at the 95 percent confidence level, a maximum margin of error of ± 2.0 percent.

Each of the two survey samples were statistically weighted by primary account holder age, housing type and region to their known population distributions to further ensure that findings were generalizable to the entire customer base of interest. These three parameters were chosen because many key areas of interest in the survey were proven to be highly correlated with them and because they are in fact among the very few parameters whose population distributions can be ascertained from the BC Hydro billing system.

Findings from BC Hydro's 2014 and 2017 Residential End-Use Studies were leveraged – due to their very large sample sizes and representativeness – to serve as population proxies in confirming the reliability of the RIB survey samples.

Refer to Appendix C for additional details on the RIB customer surveys, the Residential End-Use Studies as well as the statistical tests used in the analysis. Refer to Appendix D for the detailed RIB survey results and Appendix E for the RIB survey instrument.

2.4 Alternative Methodologies

This section describes alternative methods that were considered and rejected for this evaluation.

An intervention model is a linear regression model of bi-monthly residential electricity sales that includes a RIB rate indicator (dummy) variable to indicate the presence of the RIB rate beginning in October 2008 along with all other expected drivers of electricity consumption as described in Section 2.3.1. Theoretically, this method can produce direct estimates of the RIB rate's average conservation impact over the analysis period. However, it cannot produce a price impact for each year, nor can it take advantage of year-over-year price changes to estimate price elasticity. Since it does not produce an estimate of price elasticity, this method did not meet all the evaluation objectives and it was not adopted. Preliminary investigation into this method indicated that statistically significant savings induced by the RIB rate existed.

An experimental design using a control group was considered to estimate the flat rate elasticity as a baseline elasticity. A small number of BC Hydro residential customers that volunteered to participate in a Conservation Research Initiative ("CRI") Pilot in 2006 were excluded from the RIB rate in 2008 in order to form a control group. Preliminary analysis of customer characteristics indicated that CRI Pilot participants were not representative of the general population of RIB rate customers, so the experimental design method was rejected and further analysis was not pursued. BC Hydro dissolved the control group in 2017 with the approval of the BC Utilities Commission. As a result, a control group for the RIB rate no longer exists.

A second group of New Westminster electricity customers, who pay for their electricity under a flat rate structure, was analyzed to see if it could offer a proxy estimate of flat rate elasticity among BC Hydro customers. The econometric analysis of this group did not yield statistically significant estimates of price elasticity under a flat rate.

A separate analysis of billing data at the level of individual customer accounts for a sample of 1,000 randomly selected customers was also considered. The price elasticity estimated from such a sample of customers should be representative of the overall population. This method was rejected due to the lack of necessary and detailed demographic, socio-economic and end-use data at the individual customer level.

2.5 Uncertainty and Threats to Validity

Uncertainty and Threats to Validity: Estimates of Price Elasticity and Conservation Impacts

The method adopted for this evaluation is mainly an analysis of electricity consumption and the underlying factors driving consumption changes. As the consumption model could be specified in different functional forms, different model specifications could lead to different price elasticity estimates. The accuracy of a price elasticity estimate depends on the appropriateness of the econometric model and the availability of information and data that can be applied to the model. Models with an over-simplified specification or missing critical variables or models with irrelevant variables can both lead to biased estimates of price elasticity.

The models adopted in the evaluation cover the most important factors that influence electricity consumption to avoid biased modelling results. To address the potential for bias of price elasticity estimates, this evaluation tested alternative forms of the models, including the inclusion or exclusion of DSM savings and expenditures, to examine if such variables affect the price elasticity estimates. For this reason, the internal validity of the elasticity estimates is considered high. The external validity of Step 1 and Step 2 price elasticity estimate is also considered high given that the data used for the analysis covers the entire residential class.

The accuracy of Step 1 and Step 2 price elasticity is considered high and so are the estimates of the Step 1 and Step 2 rate impacts. However, the ability to attribute conservation effects directly to the RIB rate (an aspect of internal validity) is considered moderate as the validity of the estimate of conservation under the baseline flat rate scenario is moderate. The accuracy of the impact evaluation with this method also depends on the accuracy of the baseline or counterfactual: how much electricity would have been consumed in the absence of the RIB rate? This is difficult to estimate because it is a hypothetical scenario. This evaluation produced a range for flat rate elasticity in F2016-F2017 based on the Step 1 and Step 2 price elasticity estimates. This range was then used to estimate the conservation effects which would have occurred in the absence of the RIB rate. However, because a precise estimate of flat rate elasticity was not empirically derived, the precision of the natural conservation impact, based on the range estimate of flat rate elasticity, is not high. Prior to F2016, a planning assumption was used for flat rate elasticity, which was in turn an input into the estimation of natural conservation. As a result there is greater uncertainty associated with the estimate of natural conservation in F2013 to F2015 compared to F2016 to F2017. This in turn affects the certainty of the RIB conservation impact estimate, which has been identified as a limitation in this evaluation.

Uncertainty and Threats to Validity: RIB Surveys

The main threats to the validity of the data collection approach and accompanying findings are tied to two concepts: 1) response bias, and 2) non-response bias and representativeness.

Response bias can occur when the structure of the survey, the presentation of information in the survey, the survey questions and/or the response options influence the responses of customers away from accurate or truthful responses. This potential source of bias was mitigated by administering what is believed to be well-structured, well-ordered, unambiguous and non-leading questions together with balanced response scales that covered the potential range of customer opinion.

One particular type of response bias is 'social desirability response bias' whereby respondents provide answers that they believe an interviewer may want to hear and/or answers that they believe are consistent with the preferred outcome of the study. This potential source of bias was mitigated by utilizing a self-administered survey approach rather than an interviewer led approach.

Non-response bias can occur when subjects comprising the final survey sample are significantly different in the key exploratory parameters of interest than eligible subjects in the same population who did not complete a survey. Among a host of other possibilities, these responders may be different than non-responders on these exploratory parameters because their demographic, geographic, attitudinal or behavioural makeup is different. This can render the survey sample not wholly representative of the population.

Proving the existence or non-existence of non-response bias in a survey sample requires either 1) a follow-up survey sample of the non-responders or 2) an understanding of the true population distribution of the exploratory parameters of interest. Follow-up surveys with non-responders are very rarely conducted because they often incur additional costs, extend research timelines, and most often come with their own group of non-responders. Having an understanding of the true population distribution of the exploratory parameters before embarking on a survey is generally rare – the absence of this information is the very reason for conducting the survey in the first place.

Non-response bias was mitigated by the fact that high response rates were achieved on the surveys – the higher the response rate and the greater the coverage of a survey across different groups of subjects in the population, the lower the chance that the survey sample and its findings are not wholly representative of the population. Acceptable levels of coverage or representativeness of the survey samples were also confirmed by comparing various distributions of non-exploratory parameters in those samples (e.g. region, housing type, account holder age, education, household income, etc.) to the known distributions in the population as revealed in the customer account billing system as well as the in the Residential End-Use Studies.

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3.0 Results

In this section results are organized in accordance with the evaluation objectives and research questions outlined in Table 2.1 of Section 2.1. These questions are answered using information derived from the data and methodology listed in Table 2.2.

3.1 Results for Evaluation Objective 1: Estimate Price Elasticity

Three different models[13] were explored to estimate Step 1 and Step 2 price elasticity. The price elasticity estimates from Model 1 were adopted for the calculation of RIB conservation impacts.[14] . The modelling results for all three models are listed in Appendix D.

3.1.1 Step 1 and Step 2 Price Elasticity

The previous RIB evaluation in 2013 was unable to detect Step 1 price elasticity in a statistically significant manner (at the 90% confidence level) and estimated Step 2 price elasticity to be in the range of -0.08 to -0.13 (at the 95% confidence level). In subsequent analysis in 2016 with additional data from F2013 through F2015, Step 1 price elasticity could still not be detected at the 90 percent confidence level. Step 2 elasticity was not analyzed for the period between F2005 and F2015. The current evaluation extended data up to F2017 and estimated Step 1 elasticity at -0.14 and Step 2 elasticity at -0.08 (both at the 95% confidence level or higher.)

Table 3.1: Step 1 and Step 2 Price Elasticity Estimates

Round	Time Series Analyzed	Step 1 Elasticity	Step 2 Elasticity
1	F2005-F2012	Not statistically significant	-0.08 to -0.13***[15]
2	F2005-F2015	Not statistically significant	Not analyzed
3	F2005-F2017	-0.14***	-0.08***

*** indicates the statistical significance at 95% confidence level or higher

Looking at the results of the 3 rounds of analysis shown in Table 3.1 above, the inability to estimate Step 1 price elasticity in rounds 1 and 2 is likely due to a number of factors, including a relatively low Step 1 price and relatively small changes in the Step 1 price in the F2005 to F2014 period (see Figure 2.1 in Section 2.3.1). In contrast, the current analysis had more data points and included later years when the Step 1 price experienced larger annual increases and reached higher levels. These results suggest that these latter differences in price were sufficient enough to trigger a customer response that could then be quantified by the analysis.

The 3 rounds of analysis were conducted at different points in time with slightly different model specifications. To test whether these differences in model specifications affected the analytical results, the round 3 Step 1 model was run with 2 sets of truncated data matching the time periods analyzed in the earlier 2 rounds: F2005 – F2012 and F2005 – F2015. Neither analysis produced a statistically significant estimate of Step 1 price elasticity.

Since the Step 1 price elasticity could not be detected until F2015, the estimate of -0.14 was deemed to be applicable only to F2016 and F2017. The alternative of applying the Step 1 price elasticity to the entire F2009 to F2017 period was considered but rejected due to the absence of a statistically significant estimate of Step 1 price elasticity in the first 2 rounds of analysis.

[13] See Equations 1, 2, and 3 in Section 2.3.1.
[14] Models 2 and 3 showed that DSM expenditures and savings either had no effect on the price elasticity estimate or had a coefficient with the wrong sign (e.g. positive or negative) which would bias the price elasticity estimate if left in the model. Model 1 did not have an independent variable for DSM expenditures or savings.
[15] BC Hydro (2014)

Except for this evaluation, no specific studies were found indicating that price elasticity changes over time or over a price range within a single electricity market. However, there are many studies indicating variation in price elasticity between electricity markets and across price levels and time.[16] Some academic and industry researchers have suggested that price elasticity could be non-linear within a single electricity market[17].

Model 1 estimated Step 2 price elasticity at -0.08. This estimate is at the low end of the range of price elasticity (-0.08 to -0.13) from the 2013 RIB evaluation. The latest result suggests that the customer response to the Step 2 price may have diminished with time. The current estimate indicates that in comparison to the earlier years of the RIB, customers who were exposed to Step 2 prices in recent years may have become less price responsive—measured by percentage change in consumption—to Step 2 price increases. It also indicates that their capacity and options to conserve energy while facing price increases may have been more limited in recent years. Meanwhile, Step 1 consumption has become more price sensitive in recent years.

3.1.2 Flat Rate Elasticity (Natural Conservation)

As discussed in Step 5 of Section 2.3.1, the current evaluation was also unable to produce a statistically significant estimate of flat rate elasticity and considered three options for flat rate elasticity: a) the planning assumption of -0.05, b) a proxy in the form of price elasticity in New Westminster which is served under a flat rate and c) a range of flat rate elasticity falling between the Step 1 and 2 price elasticity (e.g. -0.08 to -0.14, or a wider range if the confidence intervals on these point estimates are considered).

Option A is based on the RIB rate application in which the estimate of flat rate elasticity is low[18] and was adopted in the 2014 evaluation which was unable to produce a statistically significant estimate of flat rate elasticity. In the absence of an empirical estimate of flat rate elasticity and the Step 1 elasticity estimate being zero for the F2013 to F2015 period, the flat rate elasticity in this period is considered to be low and the planning assumption of -0.05 was applied to the F2013 to F2015 period.

With respect to option B, New Westminster is an urban municipality in the Lower Mainland with a population of approximately 70,000 that is served by a municipal electric utility and charged for electricity under a flat rate. Given the 2013 RIB evaluation was unable to produce a statistically significant estimate of flat rate elasticity among BC Hydro customers, BC Hydro attempted to estimate the flat rate elasticity among New Westminster's 32,000 residential customer accounts by analyzing their electricity consumption using the same approach as used in this evaluation. The analysis covered the period from 2005 to 2016. If the analysis was successful in producing a statistically significant estimate, the estimate could serve as a proxy for BC Hydro customers if the current evaluation was again unsuccessful in estimating flat rate elasticity in a statistically significant manner.

However, the analysis of New Westminster data did not produce a statistically significant estimate of flat rate elasticity. The flat rate elasticity estimate was -0.10 but with a low confidence level (p=0.13). This result indicated that the flat rate elasticity was in the vicinity of -0.10, but with a large error band. Other variables such as weather, dwelling type, and billing period were statistically significant drivers of electricity consumption. The results of the New Westminster analysis are provided in Appendix D.

With respect to option C, of adopting a range estimate for flat rate elasticity falling between -0.08 and -0.14, since the Step 1 price elasticity estimate of -0.14 was deemed to only be applicable to F2016 and F2017, the range of flat rate elasticity was similarly deemed to only apply to F2016 and F2017. This range estimate is considered reasonable because the range of flat rate elasticity is based on the empirically derived values for

[16] Chang (2016) constructed a time-series model to show that price elasticity of electricity consumption changes over time in four selected countries.
[17] See Alberini and Filippini (2011) and Yachew (2017) for the discussions that elasticity may change over price range and time.
[18] Orans, R (2008), the source and reasons for adopting this assumption were provided in the expert testimony of the 2008 BC Hydro Long-Term Acquisition Plan.

Step 1 and Step 2 price elasticity. Under a flat rate scheme, Step 1 and Step 2 consumption would be combined together and the flat rate elasticity would be collectively affected by both Step 1 and Step 2 price elasticity. Under the flat rate scenario, it is the same customers being analysed, therefore they would have experienced the same external factors (e.g. economy, weather, housing stock, percentage increases in electricity price each year etc.) and their price response would bear similarity to the Step 1 and Step 2 price response. This rationale lends support to the idea that the flat rate price elasticity should not fall too far from the verified Step 1 and Step 2 price elasticities.

3.2 Results for Evaluation Objective 2: Estimate the Conservation Impacts of the RIB Rate

As outlined in Steps 1 through 3 of Section 2.3.2, energy conservation is calculated separately for the impact of the Step 1 and Step 2 prices, natural conservation under the baseline scenario and the RIB rate structure.

Table 3.2 shows the annual changes in real prices for Steps 1, Step 2, and the flat rate. Refer to Table C.1 in Appendix C for the complete history of the rate schedule price changes since the beginning of the RIB Rate.

Table 3.2: Percentage Change in Real Prices (in 2002$)

Fiscal Year	Step 1	Step 2	Flat Rate
F2013	1.1%	5.0%	3.1%
F2014	1.6%	1.6%	1.6%
F2015	8.3%	8.3%	8.2%
F2016	4.8%	4.9%	4.8%
F2017	2.3%	2.3%	2.3%

The incremental structural savings from the RIB rate were evaluated at 23 GWh, 3 GWh, and 13 GWh between F2013 and F2015, as listed in Table 3.3. The calculations are based on the value of Step 1 elasticity (zero), Step 2 elasticity (-0.08) and flat rate elasticity (-0.05).

Table 3.3: RIB Rate Savings F2013-F2015

Fiscal Year	Step 1 Price Impact (GWh)	Step 2 Price Impact (GWh)	Natural Conservation (GWh)	RIB Structural Savings (GWh)
	A	**B**	**C**	**(A + B - C)**
Elasticity	**0.00**	**-0.08**	**-0.05**	**-**
F2013	-	49	24	23
F2014	-	16	13	3
F2015	-	74	62	13

After adopting a flat rate elasticity range (-0.08 to -0.14), natural conservation and RIB structural savings in F2016 and F2017 were also estimated as a range. Table 3.4 shows the calculation of natural conservation and RIB structural savings tested over four different flat rate elasticities within the range of estimates that were empirically verified for Step 1 and Step 2 price elasticity: -0.08, -0.09,-0.10 and -0.14. Based on this calculation, savings appear to decrease as flat rate elasticity increases. The evaluated RIB energy savings in F2016 and F2017 were deemed to be small or zero, as shown in Table 3.5.

Table 3.4: RIB Rate Savings F2016-F2017

	Step 1 Price Impact (GWh)	Step 2 Price Impact (GWh)	Natural Conservation (GWh)				RIB Structural Savings (GWh)			
	A	B	C				(A + B- C)			
Elasticity	-0.14	-0.08	-0.08	-0.09	-0.10	-0.14	-0.08	-0.09	-0.10	-0.14
F2016	26	45	60	67	75	104	11	4	(3)	(33)
F2017	13	23	29	33	37	52	6	2	(2)	(16)

Evaluated savings are lower than what has been reported for F2013 through F2017. Table 3.5 compares reported and evaluated savings from the RIB rate structure.

Table 3.5: Reported and Evaluated RIB Rate Savings

	Energy Savings (GWh)		Peak Demand Savings (MW)	
Fiscal Year	Reported	Evaluated	Reported	Evaluated
F2013	42	23	9	5
F2014	19	3	4	1
F2015	59	13	12	3
F2016	29	0 to 11	6	0 to 2
F2017	8	0 to 6	2	0 to 1

The evaluated peak demand savings, calculated using the peak-to-energy ratio of 0.205 MW/GWh derived from the residential rate class load shape, range from (7) MW to 6 MW during the evaluation period.

Two major factors contribute to the variance between reported and evaluated RIB rate savings. First, the Step 2 price elasticity of -0.08 (in absolute value) is less than the planning assumption of -0.1. Second, the flat rate elasticity values applied to F2016 and F2017 were higher (in absolute value) than the value used in the forecast of RIB savings (-0.05). These two reasons were the major factors contributing to the smaller savings attributed to the RIB.

3.3 Results for Evaluation Objective 3: Analyze Differences in Price Elasticity by Customer Characteristics

Price elasticity associated with different customer profiles or characteristics were further analyzed through econometric modelling by different customer segments. The analysis was broken down by region, dwelling type, and space heating fuel. Additional analysis also estimated the difference in price elasticity between winter and summer. Results are shown at the 95 percent confidence level. N/A indicates that the estimates were not statistically significant at the 95 percent confidence level.

3.3.1 Price Elasticity by Region

Price elasticity was analyzed separately for four different geographic regions in BC Hydro's service territory: Lower Mainland, Vancouver Island, Southern Interior and North. The Step 1 price elasticity estimate in each region is listed in Table 3.6. The previous evaluation was unable to detect Step 1 price elasticity in a statistically significant manner. The current evaluation was able to detect it in three out of four regions.

Table 3.6: Step 1 Price Elasticity by Region

Evaluation	Lower Mainland	Vancouver Island	Southern Interior	North
2013	N/A	N/A	N/A	N/A
2018	-0.22	-0.18	N/A	-0.23

Step 2 price elasticities by region are listed in Table 3.7. Vancouver Island was the only region where the Step 2 price elasticity was statistically significant. The current and previous evaluations indicated that Vancouver Island had the highest Step 2 price elasticity and this finding aligns with the survey results from both evaluations.

Table 3.7: Step 2 Price Elasticity by Region

Evaluation	Lower Mainland	Vancouver Island	Southern Interior	North
2013	-0.11 to -0.13	-0.15	0.08 to -0.12	-0.12 to -0.15
2018	N/A	-0.12	N/A	N/A

While the estimate of Step 2 price elasticity is significant in the BC Hydro service territory as a whole, when the analysis is conducted by region, Step 2 price elasticity is not statistically significant in 3 of 4 regions. The regional analysis indicates that price sensitivity to the Step 2 price has become unidentifiable or insignificant in many parts of BC Hydro's service territory, and that variables other than price have a stronger influence on electricity consumption in those regions.

3.3.2 Price Elasticity by Dwelling Type

Step 1 and Step 2 price elasticity for the four major dwelling types are presented in Table 3.8 and 3.9. Step 1 price elasticity by dwelling type could not be estimated in the previous evaluation, but was identified, with statistically valid estimates, in the current evaluation.

Table 3.8: Step 1 Price Elasticity by Dwelling Type

Evaluation	Single Family Dwelling	Row/Town House	Apartment	Mobile Home
2013	N/A	N/A	N/A	N/A
2018	-0.04	-0.14	-0.26	-0.12

Compared to the previous evaluation, there were changes in Step 2 price elasticity by dwelling type. Price elasticity decreased among Single Family Dwellings but increased among Row or Townhouses and Apartments.

Table 3.9: Step 2 Price Elasticity by Dwelling Type

Evaluation	Single Family Dwelling	Row/Town House	Apartment	Mobile Home
2013	-0.08 ~ -0.14	-0.06 ~ -0.07	-0.03 ~ -0.04	-0.10
2018	-0.08	-0.10	-0.07	-0.09

3.3.3 Price Elasticity by Space Heating Type

Step 1 and Step 2 price elasticity for two space heating types are presented in Table 3.10 and 3.11. The previous evaluation did not estimate Step 1 price elasticity by space heating type in a statistically significant manner. The current evaluation did. The higher elasticity value for non-electric heat suggests that the Step 1 price response comes not only from space heating but also from other end-uses.

Table 3.10: Step 1 Price Elasticity by Heating Type

Evaluation	Electric Heat	Non-electric Heat
2013	N/A	N/A
2018	-0.11	-0.18

Unlike in the previous evaluation, Step 2 price elasticity for electrically heated customers could not be identified in the current evaluation, which suggests that space heating may not be the major source of Step 2 price response among most Step 2 customers.

Table 3.11: Step 2 Price Elasticity by Heating Type

Evaluation	Electric Heat	Non-electric Heat
2013	-0.14	-0.08 ~ -0.09
2018	N/A	-0.17

3.3.4 Difference in Price Elasticity between Winter and Summer

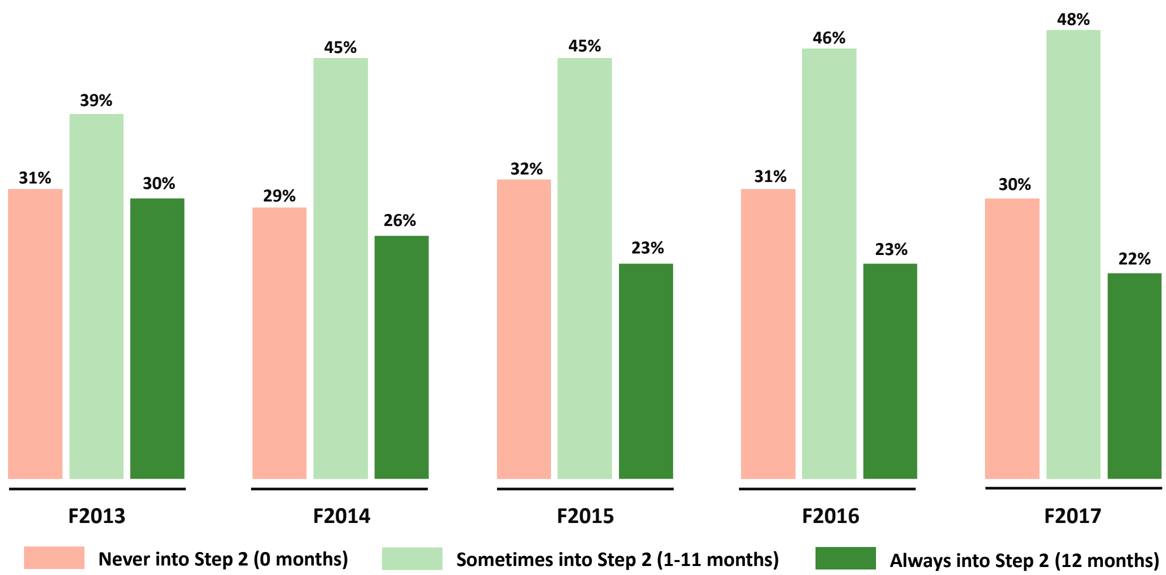
The econometric analysis of price elasticity differences between winter (November, December, January and February) and summer (June, July and August) shows no statistically significant difference in Step 1 price elasticity. For Step 2 price elasticity, the difference between winter and summer is -0.05, with Step 2 price elasticity more negative in winter than in summer. This result indicates that customers exposed to Step 2 consumption, are more price responsive in the winter compared to the summer. Due to the short time period and lack of contrast in consumption, the econometric modelling was unable to separately analyse the winter or summer period. Therefore, there was no separate estimate of winter or summer price elasticity. Based on the Step 2 elasticity estimate of -0.08 and the difference in elasticity between winter and summer of -0.05, it is expected that the Step 2 price elasticity estimate is in the vicinity of -0.05 in summer and in the vicinity of -0.11 in winter.

3.4 Results for Evaluation Objective 4: Evaluate Customer Response and Understanding of the RIB Rate

3.4.1 Customer Exposure to Step 2 Electricity Consumption

While the econometric models to estimate elasticity grouped all RIB rate customers into 'small' (Step 1 only) and 'large' (Step 2 only) consumption groups, much of the analysis presented herein uses three consumption bins to help further profile customers in terms of their exposure to Step 2 consumption through the evaluation period. For each fiscal year, Figure 3.1 details how RIB rate customers' electricity consumption distributed into the three unique consumption bins: the percentage of customer households that never (0 months), sometimes (1-11 months) or always (12 months) incurred Step 2 consumption in the twelve months of the fiscal year[19].

Figure 3.1
Incidence of Step 2 Electricity Consumption by Fiscal Year



Through the five fiscal years, the proportion of customer households that never incurred Step 2 consumption remained generally unchanged at approximately 30 percent. However, there was a change among the balance of customers in that there was an increase from 39 percent to 48 percent in the proportion that sometimes incurred Step 2 consumption while – accordingly – there was a decrease from 30 percent to 22 percent in the proportion that always incurred Step 2 consumption. The reasons for the changes are unknown, but they likely include those related to factors such as weather, changes in regulations, technological improvements, and conservation.

Incidence of Step 2 Electricity Consumption in F2017 by Region and Dwelling Type

Looking strictly at F2017, customer households on Vancouver Island were the most likely to have incurred Step 2 electricity consumption that year – 81 percent did so in at least one month of the year, including some 27 percent that always did so in all twelve months. As detailed in Appendix D, these findings reflect that nearly one-half of customers on Vancouver Island rely on electricity for both their space heating and water heating needs and that these end-uses were key determinants of Step 2 consumption.

[19] For each fiscal year, only accounts open the entire year were included in the analysis.

Customer households in the Lower Mainland were the least likely to have incurred Step 2 consumption in F2017 – only 64 percent did so in at least one month of the year. This finding is due in part to the fact the Lower Mainland is comprised of a much larger share of apartments and condominiums than other regions and the fact that these smaller dwellings – most without their own hot water heaters – are the least likely to incur any Step 2 consumption.

Table 3.12: Incidence of Step 2 Electricity Consumption in F2017 by Region and Dwelling Type

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total	Total Sometimes + Always into Step 2
Total	30%	48%	22%	100%	70%
Region					
Lower Mainland	36%	44%	20%	100%	64%
Vancouver Island	19%	53%	27%	100%	81%
Southern Interior	23%	53%	24%	100%	77%
North	22%	54%	24%	100%	78%
Dwelling Type					
Single detached house	17%	49%	34%	100%	83%
Duplex/Row house/townhouse	22%	64%	14%	100%	78%
Apartment/Condominium	65%	34%	1%	100%	35%
Mobile home/other	24%	58%	18%	100%	76%

Regional distributions are based on the billing system. Dwelling type distributions are based on the survey sample.
Row totals may not total 100% due to the rounding of values.

At 83 percent, customers living in single detached houses were the most likely to have incurred Step 2 consumption in F2017. This incidence measured slightly lower at 78 percent among customers living in duplexes, row houses or townhouses and at 76 percent among those living in mobile or other dwellings, but much lower at just 35 percent among those living in apartments and condominiums.

All of these particular patterns and differences in exposure to Step 2 consumption in F2017 – as well as those that tie to other parameters such as space heating and water heating fuels – are very similar to those first uncovered in the 2013 evaluation. Refer to Appendix D for the details pertaining to F2017.

3.4.2 Opinions of BC Hydro's Residential Electricity Prices

Several lines of questions in each of the 2012 and 2017 surveys focussed on customer opinions about the price of electricity and their electricity bills in the context of the RIB rate structure. However, in view of the possibility that not all customers think about the price of electricity in regards to the RIB rate, respondents were first asked – before seeing any RIB rate content – for their opinions about BC Hydro's residential electricity prices in a broader sense[20].

Opinion of BC Hydro's Current Residential Electricity Prices

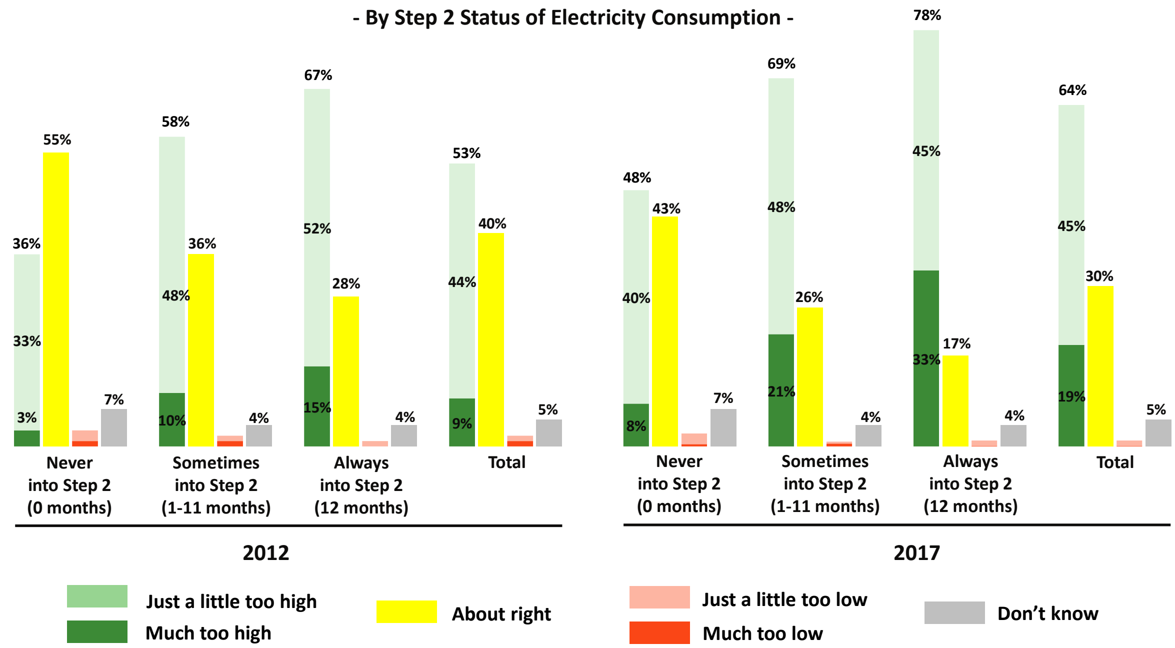
In the 2012 survey, 53 percent of customers felt that electricity prices were either 'just a little too high' or 'much too high', but this slim majority in sentiment increased to 64 percent in the 2017 survey.

In each of the two surveys, customer opinions of the current residential electricity prices varied strongly with their incidence of Step 2 electricity consumption. As illustrated in Figure 3.2 on the following page, for customers that never incurred Step 2 electricity consumption in F2012, the majority of them – 55 percent – felt

[20] Before being asked their opinion of electricity prices in the survey, respondents were first asked to rate the extent that the amount of money that their household pays for its consumption of electricity represented 'value for money'. In doing so, it is believed that their opinions about 'price' were comparably more considered and thoughtful than had the 'value for money' question not been asked.

that electricity prices were ‘about right’. To compare, the proportion who felt this way measured much lower at 36 percent among households that sometimes incurred Step 2 consumption in the fiscal year and at 28 percent among households that always did so. For these two particular cohorts, the majority of customers felt that the current electricity prices were either ‘just a little too high’ or ‘much too high’.

Figure 3.2
Opinion of BC Hydro’s Current Residential Electricity Prices
- By Step 2 Status of Electricity Consumption -



The pattern of opinions toward electricity prices identified in the 2012 survey emerged again in the 2017 survey, but with some notable shifts over the five year period. In each of the three cohorts, there were increases in the proportion of customers who felt that electricity prices were too high – including doublings in those who felt that the prices were ‘much too high’. Notably, for customers that never incurred Step 2 electricity consumption in F2017, there was no longer a majority who felt that prices were ‘about right’.

These results may help to explain why Step 1 elasticity was not detected until the third round of analysis that included data for the years F2016 to F2017. Step 1 customers who felt that electricity prices were ‘about right’ would be comparably less likely to be responsive to price increases than those who felt that prices were already ‘just a little too high’ or ‘much too high’.

Refer to Appendix D for additional findings in regards to customer beliefs in regards to price changes over the previous three years.

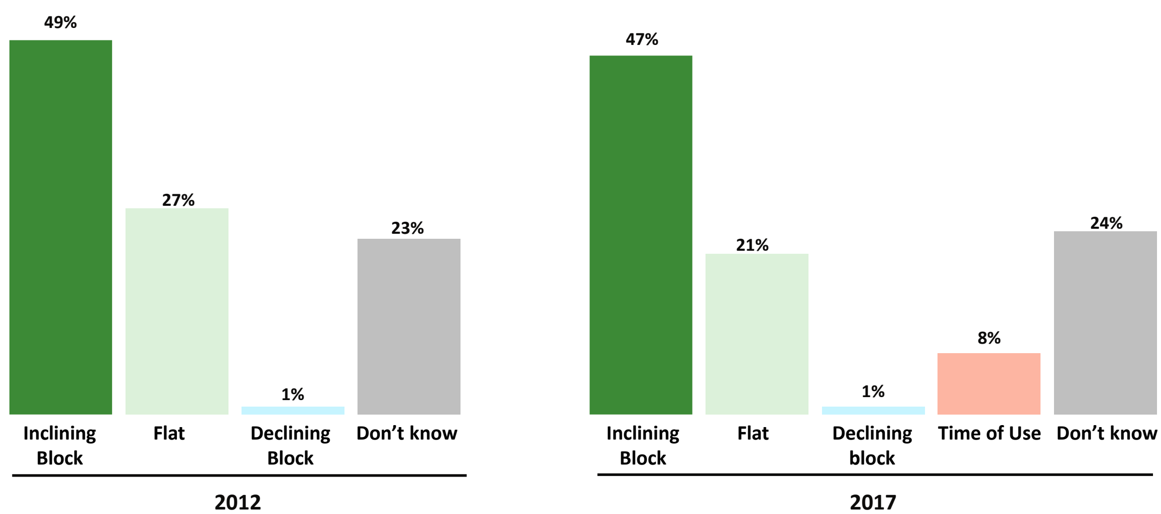
3.4.3 Awareness and Opinions of BC Hydro’s Residential Rate Structure

Unaided Awareness of BC Hydro’s Residential Rate Structure

To measure customers’ awareness of BC Hydro’s residential rate structure, a series of different rate explanations were presented in the survey and questions administered to derive their actual awareness prior to receiving the survey – that is, awareness uncontaminated by the survey content itself. It is also important to note that the context of interest was awareness of the rate structure in concept – not necessarily awareness by name such as the ‘Residential Inclining Block’ or the ‘Two-Step Residential Conservation Rate’. Figure 3.3 on the following page details the findings pertaining to 2012 and 2017.

At 49 percent in 2012 and 47 percent in 2017, there has been no meaningful change over the past five years in the proportion of customer respondents who demonstrate a previous awareness that BC Hydro charges their household's consumption of electricity on an inclining block rate – also described as a stepped rate in the survey.

Figure 3.3
Perceived Rate Structure that BC Hydro Uses to Charge for the Consumption of Electricity



The proportion of customers who believed their household's use of electricity was charged on a flat rate has dropped from 27 percent to 21 percent over the past five years. The initial finding and subsequent decrease is likely due in part to the fact that customers were charged on a flat rate prior to October 2008 – presumably, some of these respondents thinking it was still in effect. However, this decrease is also likely due in part to the fact that a time of use rate response option was added to the 2017 survey and the finding that 8 percent of respondents believed their consumption was charged in this manner. In other words, data analysis showed that many of these individuals would very likely have selected the flat rate in the 2017 survey had the time of use rate not been added as a response option[21].

Unaided awareness that BC Hydro uses an inclining block rate to charge residential customers for their use of electricity continues to be strongly tied to household consumption – the pathway very likely being via the magnitude of the accompanying bills and the extent that customers would be motivated to understand them. At 53 percent, households that always incurred Step 2 consumption in the twelve months of F2017 were the most likely to have been aware of the structure. Awareness measured slightly lower at 49 percent among households that sometimes incurred Step 2 consumption in the year and much lower at 39 percent among those that never incurred Step 2 consumption.

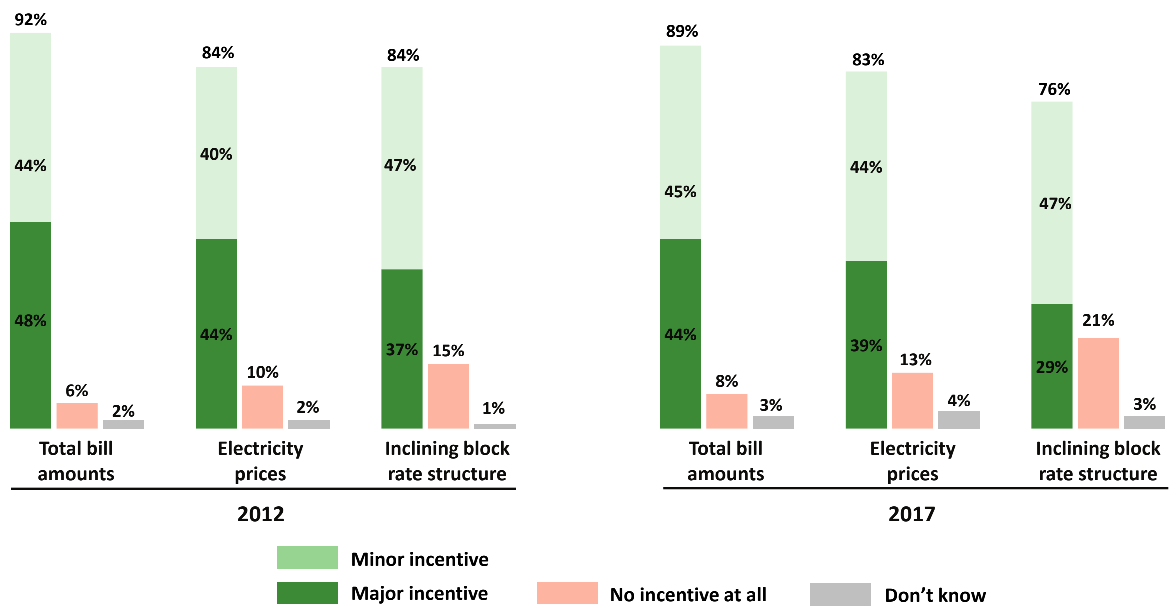
Refer to Appendix D for a complete accounting of rate awareness by all customer demographics and household sub-groups – including region, dwelling type, space heating fuel and water heating fuel.

[21] Data analysis showed that the addition of the time of use response option to the 2017 survey was not responsible for the 2-point decrease in the proportion of respondents who were coded as having a prior understanding that their consumption of electricity is charged on an inclining block rate. This is due to the rigor around the data analysis and the fact that many different lines of questions were administered in each of the 2012 and 2017 surveys to gauge and triangulate customer beliefs about the rate structure, including several strictly in regards to the inclining block rate.

Total Bill Amounts, Electricity Prices and the Inclining Block Structure as an Incentive to Manage Electricity

All customers were asked to consider – in separate lines of questions – the extent that electricity prices, their total electricity bills and the method they perceived BC Hydro uses for charging their household's consumption of electricity each served as an incentive to manage their use of it[22]. Figure 3.4 details findings from the 2012 and 2017 studies strictly among customers who correctly knew that their consumption of electricity was charged on an inclining block rate.

Figure 3.4
Extent that Total Bill Amounts, Electricity Prices and the Inclining Block Structure Serve as an Incentive to Manage Electricity
- among customer respondents with unaided awareness of BC Hydro's residential inclining block rate -



By virtue of the specific distribution of responses for each of the three factors, the total bill amounts emerged in the 2012 study as the greatest incentive to manage electricity among these customers followed by electricity prices and slightly further behind by the inclining block rate structure.

The hierarchy – the relative position of the three factors – identified in 2012 revealed itself as generally the same in 2017, but with some notable differences as detailed further below. Total bill amounts and electricity prices continued to sit in first and second position, respectively, though the specific proportion of customers assessing them as serving an incentive to manage electricity did slip marginally – the bill amounts from 92 percent to 89 percent, and the electricity prices from 84 percent to 83 percent.

The substantive change was in regards to proportion of customers who viewed the inclining block rate as an incentive to manage electricity – it decreased from 84 percent in 2012 to 76 percent in 2017. What's more, this 8-point decrease was seen entirely in the 'major incentive' response option which underscores the change in sentiment much more than had the decrease been – at least partially – in the 'minor incentive' option.

[22] In regards to electricity prices, customer respondents were reflecting on their own perception, understanding and experience with price without having been given any details about the inclining block rate – such as the Step 1 and Step 2 prices – that BC Hydro uses to charge their household for their consumption of electricity.

These changes in opinion have created sharper contrasts among the three incentive factors in 2017 than as seen in 2012. Most importantly, the inclining block rate was less seen as serving an incentive to manage electricity consumption – less in comparison to how it was viewed in 2012, and less than in 2012 in its relative comparison to total bill amounts and electricity prices.

Customer Opinion of the Price of Electricity in Relation to the RIB Rate

Customers who correctly identified that their household's use of electricity is charged on an inclining block rate may not necessarily consider or differentiate the price of electricity – as it pertains to their own household – by the Step 1 and Step 2 prices. Having been reminded that they are charged the Step 1 price for their consumption of electricity up to 1,350 kWh in an average two-month billing period and the Step 2 price for any additional consumption, these particular customers were queried in each of the 2012 and 2017 surveys as to what they considered to be their electricity price as it relates to their own household's use of it.

The single largest segment of these customers in 2017 – 46 percent – considered each of the Step 1 and Step 2 prices as being their household's price of electricity, depending on the point in time in the billing period and/or their consumption in the billing period. This is especially true for households that either sometimes or always incurred Step 2 consumption in the twelve months of F2017.

Table 3.13: Customer Opinion of the Price of Electricity in Relation to the RIB Rate - among customers previously aware of the RIB Rate in 2017 -

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total
I would say that I consider the lower, Step 1 price as being my household's price of electricity in a billing period	49%	15%	7%	22%
I would say that I consider the higher, Step 2 price as being my household's price of electricity in a billing period	4%	9%	14%	9%
I would say that I consider each of the Step 1 and Step 2 prices as being my household's price of electricity, depending on the point in time in the billing period and/or our consumption in the billing period	32%	52%	48%	46%
I do not think about my household's price of electricity in any of these particular ways	13%	22%	27%	21%
Don't know	2%	2%	3%	2%
Total	100%	100%	100%	100%

Column totals may not total 100% due to the rounding of values.
Binning of Step 2 status is based on electricity consumption in F2017.

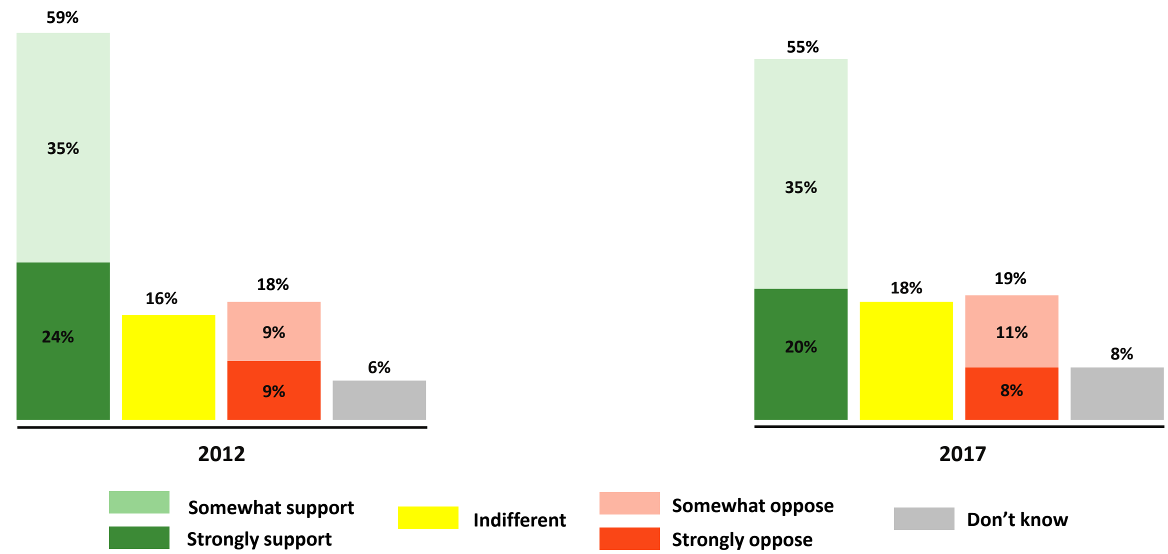
A total of 22 percent of customer contacts who correctly understood that their household's consumption of electricity is charged on an inclining block rate considered the lower, Step 1 price as being their household's price of electricity in a billing period. This sentiment increased substantially to 49 percent strictly among households that proved to have never incurred Step 2 consumption in F2017. Only a small minority of customers – 9 percent – considered the higher, Step 2 price as being their household's price of electricity in a billing period. The balance of most other customers – 21 percent – revealed that they do not think about their household's price of electricity in any of the three given ways.

A very broad view of these findings suggests that many of these customers who correctly identified that their household is on an inclining block rate have a logical understanding and view of the price of electricity. These results remain largely unchanged from the 2012 survey.

Customer Support of the RIB Rate

The total proportion of customers who support the RIB rate that BC Hydro uses to charge for their consumption of electricity – including those who may have learned about it for the first time in the survey – has decreased from 59 percent to 55 percent over the past five years. This 4-point decrease in support of the RIB rate has transferred to a 2-point increase to 18 percent in the proportion of customers indifferent about the rate and a 1-point increase to 19 percent in those opposed to it.

Figure 3.5
Customer Support of the RIB Rate



While the slip in support of the RIB rate does not mark a wholesale change in sentiment, it is statistically significant at the 99 percent level of confidence. This indicates that this change very likely occurred among the population of all RIB rate l customers – not just among those in the survey samples. Note also that this decreased support was detected in nearly all customer sub-groups (i.e. by region, dwelling type, etc.).

As found in the 2012 study, customer opinion of the RIB rate in 2017 was most correlated – and very strongly so – to their exposure to Step 2 electricity consumption. Support for the structure measured highest at 68 percent among customers who never incurred Step 2 consumption in F2017; many of them living in apartments or condominiums that often do not to breach the Step 2 threshold. Support measured much lower at 52 percent among households that sometimes incurred Step 2 consumption and at just 42 percent among those that always did so.

3.4.4 Customer Behaviour in Relation to Awareness of the RIB Rate

Electricity Consumption by Awareness of the RIB Rate

As first uncovered in the 2013 evaluation, average Step 1, Step 2 and total electricity consumption in F2017 measured higher among customer households aware of the RIB rate than among other households.

Table 3.14: ANOVA Tests: Mean Electricity Consumption in F2017 by Awareness of the RIB Rate

	Customers aware of the RIB Rate	Customers not aware of the RIB Rate	Difference between groups
Total F2017 consumption ⇒	10,447 kWh	8,707 kWh	1,740 kWh*
Total Step 1 consumption ⇒	6,305 kWh	5,777 kWh	528 kWh*
Total Step 2 consumption ⇒	4,142 kWh	2,930 kWh	1,212 kWh*

* The difference between mean consumption levels is statically significant at the 99% level of confidence.

Statistical analysis – namely, analysis of variance and linear regression – indicated a causal path whereby higher consumption leads to a greater likelihood of being aware of the rate. Refer to Appendix D for the details.

It is worthy to note that when comparing their consumption over time, households aware of the RIB rate may have lower energy consumption than had they not been aware of the rate and/or lower energy consumption than in periods prior to becoming aware of the rate.

Investments in Home Energy Efficiency Upgrades by Awareness of the RIB Rate

Customers in the 2017 survey were queried as to whether they had completed any home energy efficiency upgrades in the past three years to understand whether such investments differ by awareness of the RIB rate. Those who knew that their consumption of electricity was charged in this way were slightly more likely than others to have completed at least one of the eight upgrades investigated (52% vs. 48%), including more likely to have completed draft proofing upgrades (21% vs. 15%) and insulation upgrades (16% vs. 12%).

Table 3.15: Investments in Home Energy Efficiency Upgrades by Awareness of the RIB Rate

	Customers aware of the RIB Rate	Customers not aware of the RIB Rate	Difference between groups
	⇓	⇓	⇓
Net Total: Any of the upgrades	52%	48%	4 points*
Hot water tank installation/upgrade	30%	28%	2 points
Window upgrades	24%	22%	2 points
Draftproofing upgrades	21%	15%	6 points*
Door upgrades	17%	16%	1 point
Insulation upgrades	16%	12%	4 points*
Furnace installation/upgrade	12%	12%	0
Air source heat pump installation/upgrade	4%	3%	1 point
Ground source heat pump installation/upgrade	1%	1%	0

* Statistically significant difference between the two groups at the 95% level of confidence.

As expected, customers living in single detached or semi-attached houses were much more likely to have completed any of the upgrades than those living in apartments and condominiums. In fact, analysis showed that housing type, demographics such as income, attitudes toward energy efficiency, and awareness of the RIB rate are all factors that inform customers' likelihood of having completed such upgrades. However, due to the number of these factors and their interplay with each other, any causal relationship between awareness of the RIB rate and the decision to make such investments could not be effectively isolated and measured.

Program Participation by Awareness of the RIB Rate

BC Hydro offers several programs to its residential customers to encourage them to improve energy efficiency and to adopt more energy conscious behaviours in their homes. Customers who understood that their household's consumption of electricity is charged on the RIB rate emerged to be more likely than other customers to have participated in the Residential Behaviour Program (14% vs. 6%) and the Appliance Rebate Program (14% vs. 9%) since the rate came into effect in October 2008. In addition, these RIB aware customers were more likely to have signed-up on BC Hydro's website to be able to view their detailed electricity use by the month, week, day or even hour. Refer to Appendix D for the complete findings.

For the same reasons as given in the previous sub-section above, it could not be ascertained through the research if and to what extent awareness of the rate structure led to the decision to participate in the programs.

In-Home Behaviours by Awareness of the RIB Rate

The self-reported in-home behaviours around energy use and conservation were compared between customers who correctly understood that their household's use of electricity is charged on the RIB rate and those that did not. As found in the 2012 study, customers previously aware of the inclining block rate emerged to outperform other customers on many of the conservation behaviours related to space heating, laundry, dishwashing, lighting and other energy-using equipment.

Due to the interplay among customer demographics, attitudes toward energy efficiency, awareness of the RIB rate, etc., it was not possible to measure the causal pathway that may exist between awareness of the rate and the conservation behaviours.

Appendix D details the comprehensive list of in-home behaviours investigated in the survey, including the behavioural scores disaggregated by customers previously aware of the inclining block rate and all others.

Customer Behaviour and Electricity Consumption by RIB Step 2 Price Alerts

BC Hydro's billing system shows that a total of 5 percent of customer households have signed up online to receive email notifications that indicate when their consumption of electricity is halfway to reaching the higher Step 2 price in a billing period as well as when it has reached it.

Among these customers in the 2017 survey, 64 percent reported that they typically make more of an effort to manage their consumption of electricity when their household receives the price alerts – 35 percent do not.

In regards to the entire pool of customer households that received at least one Step 2 price alert in F2017, the analysis was not able to ascertain whether the alerts had an impact on their electricity consumption during the year.

However, for households that chose to act on the price alerts, various analyses showed – depending on the comparison scenario – that their Step 1 and/or Step 2 electricity consumption in F2017 was lower than other households. The differences were not statistically significant, however, largely because the absolute number of households in the survey that received the price alerts and acted on them was not large enough to afford a high level of confidence in the findings.

3.5 Confidence and Precision

Since the RIB conservation estimates are anchored in the estimation of price elasticity, the accuracy and confidence of the savings estimates depend on the statistical significance of the elasticity estimates. The Step 1 and Step 2 elasticity estimates have very high levels of precision (with very large t-values at the 99% confidence level). The results of the evaluated Step 1 and Step 2 price impacts have a high level of precision because they are based on the highly statistically significant Step 1 and Step 2 price elasticity estimates.

In comparison, the flat rate elasticity was not empirically derived. Instead, a planning assumption of -0.05 was applied to F2013 through F2015. For F2016 and F2017, the flat rate elasticity was estimated to fall within the range of the Step 1 and Step 2 price elasticity estimates. Due to the error band associated with the Step 1 and Step 2 elasticity estimates, the range of flat rate elasticity based on the Step 1 and Step 2 price elasticity estimates could be expanded to span, for example, the 95 percent confidence intervals of those estimates[23]. As such, the flat rate elasticity estimate is less precise than the Step 1 and Step 2 elasticity estimates because it would broaden the range of the RIB structural savings estimate, expanding it both on the positive and the negative sides and providing no more certainty over the existence of significant savings.

The calculation of natural conservation impacts are based on the flat rate elasticity planning assumption (F2013-F2015) and the flat rate elasticity range estimate with relatively low precision (F2016-F2017). Therefore, the precision of the natural conservation estimate is low. Hence, the precision of the estimated savings from the RIB rate structure, as the difference between the sum of the step rate impacts and the natural conservation impact, is moderate.

Shown below are the margins of error and the confidence levels associated with the 2012 and 2017 customer surveys used in this evaluation.

Table 3.16: Uncertainty and Margins of Error of the Survey Results

	Valid Responses	Maximum Margin of Error	Confidence Level
2012 Residential Rate Survey	2,468	± 2.0%	95%
2017 Residential Rate Survey	3,307	± 1.7%	95%

3.6 Limitations

This evaluation lacks the empirical evidence to estimate the flat rate elasticity. The certainty and precision of the evaluated conservation impact of the RIB rate is affected given that a planning assumption of the flat rate elasticity was applied to F2013 through F2015, and a range estimate was applied to F2016 and F2017.

The modelling of price elasticity also has some limitations. The current approach is limited by the availability and frequency of data. Disposable income data was only available on an annual basis while all other variables were available on a bi-monthly basis. The lower frequency and lack of variability in the income data may limit the model's ability to accurately estimate the income effect on electricity consumption. The econometric models were not able to identify the impact of energy efficiency improvements from government codes and standards on electricity consumption, as well as the impact of changes in household occupancy. A time variable which could represent these to a certain extent was tested but did not emerge as a statistically significant driver of electricity consumption.

The Step 1 price elasticity estimate in this evaluation was applied to the F2016-F2017 period only given that the analyses of previous time periods did not produce a valid Step 1 price elasticity estimate. There is a possibility that Step 1 price elasticity existed prior to F2016 but it could not be detected using the available data. This possibility is considered low but adds uncertainty to the estimate of Step 1 price elasticity. Customer survey evidence also indicated that the customer response to Step 1 was low in earlier years and has only increased in recent years.

The three rounds of Step 1 price elasticity analysis indicated that price response may change over time. However, the parametric model adopted in this evaluation alone was not able to provide direct support for non-linear price elasticity. This parametric model was based on a pre-defined consumption model, which does

[23] The range of the flat rate elasticity estimates would expand to -0.04 to -0.19 if the 95% confidence intervals of Step 1 and Step 2 price elasticity were considered.

not provide the flexibility to detect the time impact on other factors in the model (such as price elasticity or income elasticity). Any non-linear effect over time may be better estimated with a non-parametric model. However, it is not certain that a valid non-parametric elasticity model could be constructed, for the purposes of this evaluation, due to a lack of variation in the available data (e.g. income data).

As discussed in Section 2.3.1, the analysis of price elasticity was conducted at the aggregate level across all residential customers, and not at the individual customer level. It is difficult to produce more comprehensive and precise electricity consumption models at the aggregate level to better estimate price elasticity. More insights and better understanding of price elasticity could be obtained from analysis at the individual customer level, but that would require the availability of more customer-level data on end-use profiles and energy efficiency standards over the analysis period.

Finally, the use of an average peak-to-energy ratio based on the residential rate class load shape adds uncertainty to the estimates of peak demand savings. The econometric analysis is unable to determine how the customer response to the RIB rate translates into energy savings during the short time frame that defines the overall system peak.

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4.0 Findings and Recommendations

4.1 Findings

Price Elasticity

1. The overall average Step 1 price elasticity was estimated to be -0.14 for F2016 and F2017. Previous analyses, covering the RIB period of F2009-F2012 and F2009-F2015, were unable to detect Step 1 price elasticity, likely due to relatively low Step 1 prices and small changes in the Step 1 price in earlier years. As a result, Step 1 price elasticity was assumed to be zero in the calculation of energy savings for F2013 to F2015, which was the same approach used in the 2013 Evaluation.

2. Step 2 price elasticity was estimated at -0.08, which is at the low end of the range from the previous evaluation (-0.08 to -0.13). This result may suggest that customer response to the Step 2 price has diminished over time.

3. A range of -0.08 to -0.14 was adopted to estimate natural conservation due to general rate increases under a flat rate in F2016 and F2017. This range spans the empirical estimates for Step 1 and Step 2 price elasticity for F2016 and F2017. In the absence of empirical estimates of flat rate and Step 1 price elasticities in the F2013-F2015 period, the planning assumption of -0.05 was applied for natural conservation in those years.

4. To obtain a proxy estimate of flat rate elasticity, an analysis of residential consumption data from F2005 to F2016 in New Westminster, a jurisdiction serviced under a flat rate, was conducted. However, it did not produce a statistically significant estimate of flat rate elasticity.

Conservation Impacts of the RIB Rate

5. The annual incremental structural savings from the RIB rate were evaluated at 23 GWh, 3 GWh, and 13 GWh between F2013 and F2015.

6. Given the range of estimated flat rate elasticity due to general rate increases, (-0.08 to -0.14), definitive results for natural conservation and RIB structural savings in F2016 and F2017 could not be determined. Calculated RIB structural savings in F2016 and F2017 decreased as the flat rate elasticity increased. As a result, RIB structural savings in F2016 and F2017 were deemed to be small or zero.

Differences in Price Elasticity by Customer Characteristics

7. Price elasticity by region: Step 1 price elasticity was detected in three out of four geographic regions compared to none in the previous evaluation[24]. Step 2 price elasticity was detected in one region compared to all four regions in the previous evaluation. These results indicate that the Step 2 price is no longer a strong factor in determining electricity consumption in a large part of BC Hydro's service area.

8. Price elasticity by dwelling type: Step 1 price elasticity was identified in four dwelling types compared to none in the previous evaluation. Relative to the previous evaluation, Step 2 price elasticity decreased among single family dwellings and increased among row or townhouses and apartments.

9. Price elasticity by space heating type: Step 1 price elasticity was detected in households with electric and non-electric primary space heating, contrary to the previous evaluation. Step 2 price elasticity was only detected in households with non-electric primary space heating, and at a lower level than in the previous evaluation. The previous evaluation detected it in both types of households. This finding

[24] BC Hydro (2014)

suggests that energy savings induced by price changes may come from sources other than electric space heating.

10. Price elasticity in winter vs. summer: The analysis found no statistically significant difference in Step 1 price elasticity between winter and summer and a difference of -0.05 in Step 2 price elasticity - with elasticity being more negative in winter than in summer. This result indicates that for Step 2 consumption, the price sensitivity and price impact are greater in winter than in summer.

Customer Response, Awareness, and Understanding

11. From F2013 through to F2017, the proportion of customer households that incurred at least some Step 2 electricity consumption remained generally even at 70 percent. Through these five years, however, there was a decrease from 30 percent to 22 percent in the proportion that were into Step 2 in each month of a fiscal year.

12. Between 2012 and 2017, there was an increase from 53 percent to 64 percent in the proportion of customers who felt that BC Hydro's residential electricity prices were too high. Furthermore, the extent that customers felt this way was highly correlated with their exposure to Step 2 electricity consumption.

13. For customers that never incurred electricity consumption beyond Step 1, there was no longer a majority in 2017 – as there was in 2012 – who felt that prices were 'about right'. The largest segment of these customers now believed prices were too high. Their beliefs around the price of electricity in each of the 2012 and 2017 surveys help to explain why a Step 1 price elasticity was not detected until the F2016 and F2017 consumption data was added to the econometric analysis.

14. Customers' unaided awareness that BC Hydro charges household consumption of electricity on an inclining block rate has gone generally unchanged over the past five years, measuring 49 percent in 2012 and 47 percent in 2017.

15. For customers previously aware of the RIB rate in each of the 2012 and 2017 surveys, their total bill amounts emerged as serving more of an incentive to manage their consumption of electricity than did electricity prices or the rate structure. In fact, the inclining block rate was considered to be less of an incentive in 2017 than it was in 2012.

16. Customers previously aware of the RIB rate in the 2017 survey were more likely than others to have completed a home energy efficiency upgrade in the previous three years, to have participated in at least one of BC Hydro's conservation programs and to have outperformed other customers on many in-home conservation behaviours. However, it could not be ascertained through the research if and to what extent awareness of the rate structure led to the decisions to engage in these activities.

17. The total proportion of customers who support the RIB rate – including those who may have learned about it for the first time in the survey – has decreased from 59 percent to 55 percent over the past five years. Support continues to measure highest among customers who never incur Step 2 electricity consumption.

4.2 Recommendations

1. Consider whether the existing rate structure continues to serve BC Hydro's business objectives and meet customer needs, given that the current RIB rate structure appeared to yield little or no energy savings in F2016 and F2017.

2. Given the finding that larger consuming customers are more price responsive in the winter than in summer, consider exploring the value of a seasonal rate, with different pricing and consumption thresholds in the winter.

3. Consider the value of targeting small electricity consumers (e.g. those living in apartments) with existing or new DSM program offers, given their increased response to price changes in recent years.

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5.0 Conclusions

Although awareness of the RIB rate has remained relatively unchanged over the past five years at just under 50 percent among all residential customers, the survey analysis has shown that a greater proportion of small customers now feel that electricity prices are too high and the econometric analysis has indicated that they have become more responsive to price changes.

Overall, the RIB rate appears to have achieved its objective of encouraging conservation through the customer response to higher marginal prices. However, the effectiveness of the RIB rate in yielding electricity savings appears to have diminished over time.

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Evaluation Oversight Committee Signoff

BC Hydro's Evaluation Oversight Committee is made up of DSM stakeholders from various parts of the company and is mandated to ensure that BC Hydro's DSM evaluations are objective, unbiased and of sufficient quality.

The F20013-F2017 RIB evaluation meets the following criteria for approval by the Evaluation Oversight Committee:

1. The evaluation complied with the defined scope.
2. The evaluation methodology is appropriate given the available resources at the time of the evaluation.
3. The evaluation results are reasonable given the available data and resources at the time of the evaluation.

Serina Grahn
Evaluation Oversight Committee Chair

May 4, 2018
Date

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Abbreviations and Glossary

BCUC: British Columbia Utilities Commission

CDD: Cooling Degree Days. A measurement to reflect the amount of energy required to cool a building derived from outdoor air temperature. Cooling degree days are defined relative to a base temperature (18°C).

CRI: Conservation Research Initiative – A pilot project started in November 2006 to investigate the capabilities of smart meters including critical peak pricing and load control components.

DSM: Demand Side Management

Evaluated Savings: Savings estimates reported after the energy efficiency activities have been implemented and an impact evaluation has been completed.

Experimental Design: Also known as a randomized controlled experiment where participants in the experiment are randomly assigned to either the treatment or control group to attempt to isolate the effects of the treatment itself from all other (unknown) sources of variation.

HDD: Heating Degree Days. A measurement to reflect the amount of energy required to heat a building derived from outdoor air temperature. Heating degree days are defined relative to a base temperature (18°C).

Natural Conservation: Refers to those efficiency improvements that would occur in the absence of any DSM activity. Natural conservation may be due to equipment efficiencies, behaviors, changes to codes and standards or simply reactions to rate increases.

OLS: Ordinary Least Squares - a method for estimating the unknown parameters in a linear regression model. This method minimizes the sum of squared vertical distances between the observed responses in the dataset and the responses predicted by the linear approximation.

Reported Savings: Savings estimates reported by a program or initiative implementer/administrator after an energy efficiency activity has been completed. Also called *claimed savings* or *tracking estimates.*

RIB: Residential Inclining Block

Quasi-experiment: In a quasi-experimental design, there is no random assignment to a treatment or control group. Treatment and comparison group members are matched on relevant characteristic(s).

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Appendix A: Results Summary

Evaluation Objective 1: Price Elasticity

Table A.1: Step 1 and Step 2 Price Elasticity Estimates

Round	Time Series Analyzed	Step 1 Elasticity	Step 2 Elasticity
1	F05-F12	Not statistically significant	-0.08 to -0.13***
2	F05-F15	Not statistically significant	Not analyzed
4	F05-F17	-0.14***	-0.08***

*** indicates the statistical significance at 95% confidence level or higher

Evaluation Objective 2: Conservation Impacts of the RIB Rate

Table A.2: RIB Rate Savings F2013-F2015

Fiscal Year	Step 1 Price Impact (GWh)	Step 2 Price Impact (GWh)	Natural Conservation (GWh)	RIB Structural Savings (GWh)
	A	**B**	**C**	**(A + B - C)**
Elasticity	**0.00**	**-0.08**	**-0.05**	**-**
F2013	-	49	24	23
F2014	-	16	13	3
F2015	-	74	62	13

Table A.3: RIB Rate Savings F2016-F2017

	Step 1 Price Impact (GWh)	Step 2 Price Impact (GWh)	Natural Conservation (GWh)				RIB Structural Savings (GWh)			
	A	**B**	**C**				**(A + B- C)**			
Elasticity	**-0.14**	**-0.08**	**-0.08**	**-0.09**	**-0.10**	**-0.14**	**-0.08**	**-0.09**	**-0.10**	**-0.14**
F2016	26	45	60	67	75	104	11	4	(3)	(33)
F2017	13	23	29	33	37	52	6	2	(2)	(16)

Table A.4: Reported and Evaluated RIB Rate Savings

	Energy Savings (GWh)		Peak Demand Savings (MW)	
Fiscal Year	Reported	Evaluated	Reported	Evaluated
F2013	42	23	9	5
F2014	19	3	4	1
F2015	59	13	12	3
F2016	29	0 to 11	6	0 to 2
F2017	8	0 to 6	2	0 to 1

Evaluation Objective 3: Differences in Price Elasticity by Customer Characteristics

Table A.5: Step 1 and Step 2 Price Elasticity by Customer Characteristics

Customer Segment	Step 1 Elasticity	Step 2 Elasticity
Region		
Lower Mainland	-0.22***	Not statistically significant
Vancouver Island	-0.18***	-0.12***
Southern Interior	Not statistically significant	Not statistically significant
North	-0.23***	Not statistically significant
Dwelling Type		
Single Family Dwelling	-0.04***	-0.08***
Row/Townhouse	-0.14***	-0.10***
Apartment	-0.26***	-0.07***
Mobile Home	-0.12***	-0.09***
Space Heating		
Electric	-0.11***	Not statistically significant
Non-Electric	-0.18***	-0.17***
Winter vs. Summer		
	Not statistically significant	Winter is more negative than summer by -0.05

*** indicates statistically significant at 95% confidence level

Appendix B: Evaluation Advisor Memos

May 9, 2018

To: BC Hydro

From: Rafael Friedmann
Evaluation Consultant
Oakland, California, USA

Re: Evaluation of the Residential Inclining Block Rate F2013-F2017

1. What is your assessment of the quality of the research design? If you identify any shortcomings, what is your assessment of their potential risk for the validity of the evaluation results?

   The research design and objectives make sense, but the ability to get actionable results was limited by two main factors: i) better understanding of how the RIB, the absolute energy bill, and other factors played into customers' actions; and ii) getting a solid counterfactual (the flat rate case).

2. What is your assessment of the quality of the input data? If you identify any shortcomings, what is your assessment of their potential risk for the validity of the evaluation results?

   The evaluation team did a great job at drawing from a variety of data sources to optimize the cost-effectiveness of the research. Input data for the most part was good. The core difficulty was getting enough data to overcome the relatively small "signal" and large amount of "noise".

3. What is your assessment of the quality of the analytical methods? If you identify any shortcomings, what is your assessment of their potential risk for the validity of the evaluation results?

   The analytical methods were sound. The focus on determining an elasticity of demand for both the RIB and the flat rate, and then estimating savings as the difference between these made sense a priori. But it appears that due to how small the elasticities were, that about ½ of the customers' surveyed didn't know they were on RIB or what it was, resulted in much lower "signal" compared to the "noise" of other factors. The ongoing increase in rates apparently had more of an effect than the RIB. A larger focus on understanding customers' reactions to both RIB and absolute increase in their rates and how these led or not to energy saving actions would have enabled a better understanding of the influence of these and how to proceed to improve rate design.

4. How does the methodology compare to common industry practice for evaluations of similar initiatives?

   Methodology for estimating elasticities is aligned with common industry practice. Similarly, with regards to estimating savings and customer understanding of rate structures. A broader and deeper use of qualitative methods would have possibly provided a better understanding of customers' key motivating factors to take energy saving actions. For example, what were the synergistic effects of increasing rates and the RIB? Would the RIB have a larger effect if more effort were put to educate customers on it and the benefits of small reductions in energy having large effects on bills? How would customers react if their entire energy use were charged at the marginal rate they fell in the RIB (Mexico did this for a while)?

5. What are your suggestions for future evaluations of this DSM initiative?

   Future work should examine in more detail objective #4 – how well customers understand their rate structure and how changes to their energy use affect their bills, and whether these are material enough to effect increased conservation and energy efficiency actions by customers. Such research would provide more insight on what types of changes to the rate structure will be most effective at getting customers to modify their energy use (and potentially, at specific times of the day and year).

6. Do you have any other comments that you would like to make?

   This was a very difficult effort; very small "signal", lots of "noise". The evaluation team did a good job at drawing from a variety of data sources to develop elasticity and savings estimates. Findings offer elasticity results, but less on what to do in view of these, due to the uncertainty in these results and need for a deeper understanding of the reasons (i.e., customer motivators) behind the observed energy use changes.

Date: May 9, 2018

To: BC Hydro

From: Steven Braithwait, PhD
Vice President (retired), Christensen Associates Energy Consulting
Madison, Wisconsin

Re: Evaluation of the Residential Inclining Block Rate F2013-F2017, April 2018

1. What is your assessment of the quality of the research design? If you identify any shortcomings, what is your assessment of their potential risk for the validity of the evaluation results?

   The research design of the evaluation is of reasonably high quality for the approach chosen. That is, given that the target program involves a rate change (*i.e.*, from a flat rate to a residential inclining block rate, or RIB), the evaluators attempted to estimate price elasticities for customers' consumption on the two pricing blocks (Blocks 1 and 2). They then calculate RIB conservation impacts by applying the elasticities to the corresponding percentage changes in prices. One potential shortcoming of this design is that estimating price elasticities for a utility can be challenging due to typically small changes in prices, which also tend to follow a trend over time, leading to relatively few independent observations on price changes. Another potential shortcoming involves the element of the design that requires estimation of consumers' price elasticity for the flat rate that would otherwise have been in place. Uncertainties surrounding this estimated price elasticity and the block price elasticities results in a somewhat wide range of estimated RIB conservation impacts that vary substantially from year to year.

2. What is your assessment of the quality of the input data? If you identify any shortcomings, what is your assessment of their potential risk for the validity of the evaluation results?

   The quality of the input data is high. BCH has extensive time-series data on their customers' bi-monthly energy consumption, weather, geographical region and rates.

3. What is your assessment of the quality of the analytical methods? If you identify any shortcomings, what is your assessment of their potential risk for the validity of the evaluation results?

   The analytical methods used to estimate price elasticities for Block 1 and Block 2 consumption are competent. However, the methods used to calculate conservation impacts of RIB implementation are needlessly convoluted, leading to considerable uncertainty regarding the estimated impacts. The problems arise from the nature of the analytical approach, which assumes that the price changes to which the estimated elasticities are applied should be year-to-year changes in the individual block prices. This assumption in turn implies the need to estimate a price elasticity for the flat rate (which customers no longer experience) so that naturally-occurring price impacts may be subtracted from RIB impacts. Lacking the ability to estimate a price elasticity for a non-existing rate, the researchers make an arbitrary assumption that it is a blend of the Block 1 and 2 price elasticities, and calculate a range of conservation impacts under alternative assumptions regarding the flat rate elasticities.

As I have suggested in previous comments, a more appropriate evaluation approach would be to calculate the relevant price changes as the percentage changes in the two block prices *relative to the flat rate* that would otherwise have applied. That is, an evaluation of any program or rate involves a comparison to a counter-factual reference case of what would have occurred had the program or rate not been offered to customers. In the case of RIB, the reference case is that customers would have faced the flat rate rather than the RIB rates. Thus, the relevant price change is the difference between the relevant RIB rate and the flat rate. As a result, Block 1 customers experience prices that are approximately 15 percent <u>lower</u> than they would have been under the flat rate, while Block 2 customers see prices that are 25 percent <u>higher</u>. Under this approach to calculating RIB impacts there would be no need to estimate a separate elasticity for the non-existing flat rate; the naturally-occurring price response would be accounted for in the relative price changes.

4. How does the methodology compare to common industry practice for evaluations of similar initiatives?

   The methodology for estimating price elasticities is comparable to common industry practice for applications such as load forecasting. However, for evaluating the impacts of the RIB rate change, other methodologies, such as those used for estimating load impacts of demand response (DR) programs and dynamic pricing are more common. These are generally intervention models in which an impact variable is used to directly estimate the effect of a rate or DR program. The binary variable takes on the value *zero* in pre-RIB billing periods and *one* following RIB implementation (the variable may be interacted with time to allow time-varying impacts), such that the coefficient on the variable represents the program impact. Such variables could be included in separate regressions using billing data for Block 1 and Block 2 consumption.

5. What are your suggestions for future evaluations of this DSM initiative?

   In future analyses I would suggest exploring two alternative research paths. One would explore intervention models of the type described above (and in the report) to estimate RIB impacts directly. The other would undertake additional analyses of price elasticities using alternative methods, particularly using dynamic models that account for possible lagged, or delayed responses to price changes. Finally, I recommend a review of the assumptions regarding the price changes that Block 1 and Block 2 customers experience compared to the counter-factual flat rate.

6. Do you have any other comments that you would like to make?

   I would suggest that future evaluations also explore the relationship between RIB impacts on residential energy consumption and the impacts of BC Hydro’s DSM conservation programs. Some initial attempts along these lines were attempted in the current evaluation and are described in the report. No statistically significant results of expected signs were found, suggesting opportunities for further exploration into data on DSM expenditures and reported savings, and on methods used in the RIB evaluation to incorporate those data.

Appendix C: Approach Details

C.1. Econometric Modeling

Price elasticity analysis started with the three electricity consumption models and their basic functional forms as shown in Equations 1, 2 and 3 in Section 2.3.1. In setting up consumption models, the following factors that are significant drivers for electricity consumption at the aggregate level were considered:

Electricity Price: Economic theory holds that price impacts consumption. Historical electricity prices for residential customers were obtained from BC Hydro Tariff documents.

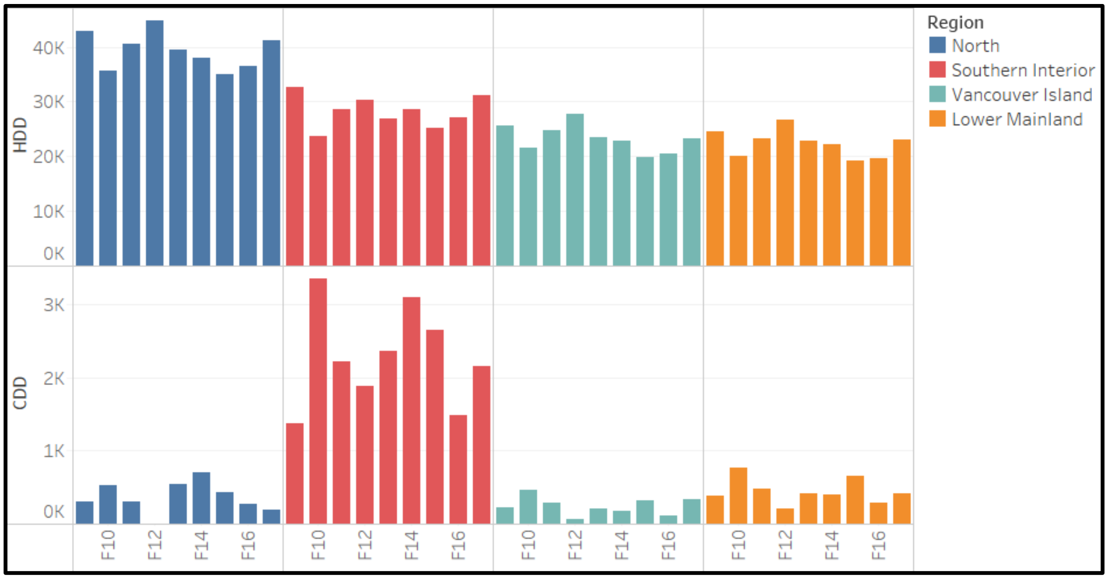
Adjusting Historical Prices using the BC CPI: Table C.1 presents a schedule of the historical prices for the Step 1, Step 2 and flat rate. The table also shows the year over year percentage change in the real price by adjusting the nominal prices for inflation, based on the consumer price index ("CPI") shown in the far-right column.

Table C.1: Historical Prices vs. Consumer Price Index

	Nominal Price (cents/kWh)			Percentage Change in Real Price from Previous Year			
Fiscal Year	Step 1	Step 2	Flat Rate (1151)	Step 1	Step 2	Flat Rate	Consumer Price Index (base year of 2002)
F2008			6.14	-	-	-	110.3
F2009	5.46	7.21	6.29	-12.8%	15.1%	0.4%	112.5
F2010	5.91	8.27	6.84	8.2%	14.7%	8.7%	112.5
F2011	6.27	8.78	7.26	4.2%	4.3%	4.3%	114.5
F2012	6.67	9.62	7.84	4.1%	7.2%	5.7%	117.0
F2013	6.8	10.19	8.15	1.1%	5.0%	3.1%	118.0
F2014	6.9	10.34	8.27	1.6%	1.6%	1.6%	117.8
F2015	7.52	11.27	9.01	8.3%	8.3%	8.2%	118.6
F2016	7.97	11.95	9.55	4.8%	4.9%	4.8%	119.9
F2017	8.29	12.43	9.93	2.3%	2.3%	2.3%	121.9

Weather: Weather affects electricity consumption through space heating, water heating and air conditioning loads. Heating Degree Days (HDD) and Cooling Degree Days (CDD) representing bi-monthly temperature variations were used to control for weather impacts on electricity consumption. Figure C.1.1 below shows the values of HDD and CDD for the four BC regions over time.

Figure C.1.1. Regional HDD and CDD from F2009 to F2017



Seasonality: Seasonality impacts electricity use through changes to the hours of daylight, seasonal holidays and other general changes in the mix of electricity end-uses based on a given time of year. Six bimonthly billing periods were used to control for seasonal impacts beyond those associated with weather.

Space heating fuel: Space heating is a large end-use of energy for BC Hydro's residential customers. Space heating in British Columbia most commonly uses natural gas or electricity followed by wood and propane. Primary space heating fuel type is estimated at the account level from the BC Hydro billing system. For the purpose of this analysis, primary space heating fuel was defined as either electric or non-electric.

Dwelling type: Dwelling type impacts electricity consumption through factors such as overall heating demand, number of appliances, number of occupants, and construction material. Dwelling type is maintained in the BC billing system using the following classifications: single family detached, row house, apartment, and mobile home.

Note that "Other" dwelling types included in the 2014 evaluation had an unusually high consumption level compared to the other categories of dwellings and showed an irregular consumption pattern in previous years. As a result, this category of residential homes (about 3% of total residential accounts) was not included in the current evaluation.

DSM Expenditures: BC Hydro's expenditures on DSM programs and sector enabling activities impacts electricity consumption by providing information and incentives for electricity conservation as well as development of codes and standards. Bi-monthly expenditures from F2005 to F2017 were obtained and allocated across the various account sub-groups (region, dwelling type, heating type) based on the number of accounts in each group. The impact of expenditures on DSM by agencies other than BC Hydro were not included because they either target different customer groups or were expected to be too small to be measured using the aggregate analysis of demand models adopted in this evaluation.

DSM Savings: Energy savings from BC Hydro's DSM programs, and federal or provincial government codes and standards have an impact on electricity consumption. Energy savings from F2005 to F2017 were collected from BC Hydro's record of DSM savings in the residential sector. Such saving impacts can be incorporated in the econometric models to test their influence on price elasticity estimate.

Economic Factors: Economic theory holds that income impacts consumption. Annual personal real disposable income in British Columbia was obtained through BC Stats. Adjustments for the impact of inflation were done using the monthly Consumer Price Index (CPI) from Statistics Canada.

Region: The BC Hydro service territory is divided into four geographic regions: Lower Mainland, Vancouver Island, Southern Interior and North. Region impacts electricity consumption through differences in demographics and lifestyle of their residents.

Interactions between variables: Adding interaction terms to the regression model may help to explain the relationships between some of the variables. For example, the relationship between weather and heating fuel type are expected to have a strong influence on overall consumption since households with electric heat would have higher consumption in colder weather compared to households with non-electric heat.

Correction Term: The bias correction term is based on the construction of a log odd regression whose dependent variable is $Y = \ln[S / (1-S)]$, where S = large user share of total accounts. Since the small user share will be (1-S), the correction term for the small user regression is based on the same log odd regression. The coefficient estimate on the correction term for the Step 2 regression is expected to be negative, based on an assumption that if a random factor causes more accounts to be in the large user group, the same factor also tends to enlarge the per account consumption. Conversely, the correction term's coefficient estimate for the small user (Step 1) regression is expected to be positive. The assumption is that if a random factor causes more accounts to be in the small user group, the same factor also tends to decrease the per account consumption.

Testing the models: Each of the econometric models was assessed for validity through:

- Statistics of the adjusted R-squared for overall regression model validity;
- Expected signs (or values) of coefficients for individual independent variables and their statistical significance;

C.2. Customer Surveys

Detailed information about the 2012 and 2017 RIB survey methodologies are presented in Section 2.3.4 of the report.

This section presents additional information in regards to the Residential End-Use Studies that were leveraged in this evaluation, an exploration of the 2017 RIB survey sample, and a description of the statistical tests used in the analysis of the RIB survey data.

C.2.1 Residential End-Use Studies

Findings from BC Hydro's 2014 and 2017 Residential End-Use Studies were leveraged – due to their very large sample sizes and representativeness – to serve as population proxies in confirming the reliability of the 2017 RIB survey sample.

As was done for the 2012 RIB survey sample in concert with the 2012 end-use study, the 2017 RIB survey sample and the distribution of customer contact demographics, household characteristics and electricity consumption were compared – and as shown in the next section, validated – to the distributions of RIB customers ascertained from the 2014 and 2017 end-use studies.

Each of the 2014 and 2017 end-use studies featured a self-administered data collection approach, and afforded respondents to complete the survey in either in a print format or online.

The 2014 study was comprised of 7,318 customer respondents on the RIB rate while the 2017 study was comprised of 6,929 customer respondents on the RIB rate.

C.2.2 2017 RIB Survey Sample Profile

This section details the distribution of the 2017 survey sample – after statistical weighting – on a number of different fronts, such as customer demographics and household characteristics, and compares the distributions to those of the population of residential customers. In doing so, a comprehensive profile of customer households is presented, and the sample is certified as being very representative of the population from which it was drawn.

Population and 2017 Survey Sample Profile of RIB Customers

Table C.2. details the population distribution of BC Hydro's 1.7 million RIB qualified customers on four known population parameters in the corporation's customer account billing system – region, dwelling type, age of primary account holder and Step 2 electricity consumption status – and the 2017 survey sample distribution of customers after statistical weighting.

The single largest segment of residential customers in 2017 – 59 percent – resided in the Lower Mainland, followed by Vancouver Island, the Southern Interior and the North. The distribution of dwelling types followed much of the same pattern in that 57 percent of customers lived in single detached houses and duplexes while most others lived in apartments and condominiums rather than in row houses and townhouses, mobile homes and 'other' types of dwellings.

Table C.2: Population and 2017 Survey Sample Profile of RIB Customers

	2017 Population*	2017 Survey Sample
Region		
Lower Mainland	59%	59%
Vancouver Island	21%	21%
Southern Interior	12%	12%
North	8%	8%
Total	100%	100%
Dwelling Type		
Single detached house/duplex	57%	57%
Row house/townhouse	9%	10%
Apartment/Condominium	28%	28%
Mobile home/other	5%	5%
Total	100%	100%
Age of Primary Account Holder		
18-24	2%	1%
25-34	11%	12%
35-44	17%	16%
45-54	21%	21%
55-64	23%	23%
65+	27%	27%
Total	100%	100%
Step 2 Consumption Status in F2017		
Never into Step 2 (0 months)	30%	31%
Sometimes into Step 2 (1-11 months)	48%	47%
Always into Step 2 (12 months)	22%	22%
Total	100%	100%

Column totals may not total 100% due to the rounding of values.
* As per BC Hydro's customer account billing system for region, dwelling type, age of primary account holder and Step 2 electricity consumption status.

As per the overall population, 71 percent of primary account holders in the 2017 survey sample were 45 years old or older, including some 50 percent who were at least 55 years old.

The distribution of customers in the 2017 survey sample also very closely followed the overall population in terms of the number of times households incurred Step 2 electricity consumption in F2017. Although most customers are billed on a bi-monthly basis and the Step 2 threshold is set at 1,350 kWh, this statistic is based on calendarized monthly consumption with the Step 2 threshold at 675 kWh.

A total of 31 percent of customers in the sample never (0 months) incurred Step 2 electricity consumption in the twelve months of F2017, 47 percent of customers sometimes (1-11 months) incurred Step 2 electricity consumption and 22 percent always (12 months) did so. This observation – underscoring the representativeness of the survey sample – is important due to the fact that customer awareness levels and opinions toward the RIB rate have proven to be highly correlated to exposure to Step 2 and overall electricity consumption.

Housing Profile of RIB Customers

As BC Hydro's customer account billing system does not include housing and demographic information beyond region, dwelling type and age, its 2017 Residential End-Use Study was leveraged to serve as a proxy for further sample comparisons to the population due to its very large sample size and representativeness. At the time of this evaluation, however, analysis of the space heating and water heating fuels in the 2017 end-use study had not been completed and, for that reason, the 2014 end-use study was instead leveraged for these two items.

Table C.3: Housing Profile of the Population and 2017 Survey Sample of RIB Customers

	2017 Population*	2017 Survey Sample
Main Space Heating Fuel		
Electricity	43%	45%
Non-Electric	57%	55%
Total	100%	100%
Main Water Heating Fuel		
Electricity	37%	35%
Non-Electric	41%	41%
No hot water tank (central)	23%	24%
Total	100%	100%
Floor Area (square feet)		
<500	1%	1%
500-1,000	24%	23%
1,001-1,500	21%	22%
1,501-2,000	17%	17%
2,001-2,500	16%	15%
2,501-3,000	10%	11%
Over 3,000	11%	10%
Average	1,869	1,857
Total	100%	100%
Year Home Built		
Before 1950	7%	8%
1950-1975	23%	24%
1976-1985	17%	19%
1986-1995	19%	16%
1996-2005	14%	15%
2006-2015	18%	17%
2016-2017	1%	1%
Total	100%	100%

Column totals may not total 100% due to the rounding of values.
* As per the distribution of RIB qualified tariff 1101 records in BC Hydro's 2017 Residential End-Use Study. Main space heating fuel and main water heating fuel as per the distribution of RIB qualified tariff 1101 records in BC Hydro's 2014 Residential End-Use Study.

Very similar to the population, 45 percent of households in the 2017 survey sample relied primarily on electricity for their space heating. A total of 35 percent of households in the 2017 survey sample relied on electricity for their home's water heating needs. It follows that 41 percent of customers relied on non-electric fuels for their hot water heating while 24 percent of customers – most of them in apartments and condominiums – received their hot water from their building's central system. The profile of survey sample in terms of dwelling floor space and vintage also very closely followed that of the overall population.

Demographic Profile of RIB Customers

The demographic composition of the survey sample was very representative of the population in terms of primary account holders being generally split by gender and by the distribution of their age (as previously shown in Table C.2.). Close to four in ten account holders had earned university degrees while the balance of others were most likely to have attended university, college, vocational or technical school.

Table C.4: Demographic Profile of the Population and 2017 Survey Sample of RIB Customers

	2017 Population*	2017 Survey Sample
Gender of Primary Account Holder		
Male	50%	48%
Female	50%	52%
Total	100%	100%
Education of Primary Account Holder		
Less than grade 12	7%	6%
High school diploma	13%	13%
Some college/vocational/technical school	18%	17%
College/vocational/technical school graduate	21%	20%
Some university	7%	7%
University/Graduate Degree	34%	37%
Total	100%	100%
Home Ownership		
Own/Co-op	80%	81%
Rent	20%	19%
Total	100%	100%
Number of Household Occupants		
1	23%	23%
2	41%	40%
3	14%	13%
4 +	22%	24%
Average number of occupants	2.5	2.6
Total	100%	100%
Household Composition		
Has children 0-5	11%	10%
Has children 6-12	12%	13%
Has young adults 13-24	19%	20%
Has adults 25-64	76%	77%
Has adults 65 +	33%	33%
Total	100%	100%

Column totals may not total 100% due to the rounding of values.
* As per the distribution of RIB qualified tariff 1101 records in BC Hydro's 2017 Residential End-Use Study.

Similar to as seen in the 2017 end-use study, a total of 81 percent of residential customers in the 2017 survey sample owned their homes.

The profile of survey respondents in terms of their household composition and household income closely followed that of all BC Hydro residential customers on the RIB rate. Households in the survey sample were comprised of an average of 2.6 people and approximately six in ten had annual earnings of $60,000 or more.

Table C.5: Demographic Profile of the Population and 2017 Survey Sample of RIB Customers (Continued)

	2017 Population*	2017 Survey Sample
Household Income		
Less than $20,000	8%	7%
$20,000 < $40,000	19%	18%
$40,000 < $60,000	17%	18%
$60,000 < $80,000	14%	14%
$80,000 < $100,000	14%	13%
$100,000 < $120,000	11%	11%
$120,000 +	19%	20%
Total	100%	100%
Low Income Status		
Yes, 'low income' household	11%	11%
No	89%	89%
Total	100%	100%

Column totals may not total 100% due to the rounding of values.
* As per the distribution of RIB qualified tariff 1101 records in BC Hydro's 2017 Residential End-Use Study.

The overall incidence of BC Hydro's RIB qualified customers in 2017 that could be classified as 'low income' as defined by Statistics Canada was estimated to have been 11 percent[25].

C.2.3 Statistical Tests

Analysis of the 2017 RIB survey sample primarily relied on frequency distributions and cross tabulations of responses. Statistical testing of differences in proportions in survey responses between groups was conducted by z-tests at the 95 percent level of confidence.

Analysis of household electricity consumption among groups of households in the survey sample was analyzed via means procedures and statistical testing of differences in means was conducted by the analysis of variance procedure at the 95 percent level of confidence.

[25] The low income cut-off (LICO) rate as defined by Statistics Canada is the percentage of families or households which fall below a low income threshold – that being, an income level whereby a family spends a larger share of its total income on the necessities of food, shelter and clothing than does an average family in an appropriate comparison group (the lower a household's income, a greater percentage of the total is tied to the necessities of living). Three variables together identify low income households of interest: annual household income, number of household occupants, and population of the household's census metropolitan area (CMA). Households with annual earnings less than the Low Income Cut-Off (LICO) for their household size and CMA population are considered low income.

Appendix D: Results Detail

D.1. Econometric Modeling Results

The results of Step 1 and Step 2 price elasticity from three econometric models are provided below. The data applied to these econometric models covered the period from April 2004 to December 2016 (F2005 through F2017).

Step 1 Price Elasticity

Model 1

Basic functional form:

$$\ln(Consumption) = \alpha + \beta \cdot Heat + \gamma \cdot Dwelling + \delta \cdot BillingPeriod + \omega 1 \cdot CDD + \omega 2 \cdot HDD$$
$$+ \mathfrak{z} \cdot Region + \varepsilon \cdot ln\,(Price) + \sigma \cdot ln\,(Disposable\_Income) + \varphi \cdot C + \mu$$

With the confidence level set at 95 percent or higher (or with the *Pr > |t|* column in the table below showing a value equal to or smaller than 0.05), the model 1 results indicate that the statistically significant (different than zero) coefficients are those associated with billing period, heating fuel type, region, dwelling type and price. Income and weather are not significant drivers for Step 1 electricity consumption as Step 1 consumption varies little with the weather or income variables.

Step 1 price elasticity is estimated at -0.14.

Root MSE	0.07357	*R-Square*	0.8613
Dependent Mean	6.64328	*Adj R-Sq*	0.8606
Coeff Var	1.10744		

Parameter Estimates

Variable	*Label*	*DF*	*Parameter Estimate*	*Standard Error*	*t Value*	*Pr > |t|*
Intercept	Intercept	1	6.80449	0.06862	99.17	<.0001
BP_1	Billing Period Apr-May	1	-0.09060	0.00712	-12.72	<.0001
BP_2	Billing Period Jun-Jul	1	-0.17511	0.00974	-17.98	<.0001
BP_3	Billing Period Aug-Sep	1	-0.13496	0.00910	-14.83	<.0001
BP_4	Billing Period Oct-Nov	1	0.02973	0.00531	5.60	<.0001
BP_5	Billing Period Dec-Jan	1	0.09209	0.00665	13.86	<.0001
D_heat_elec	Dummy Variable: Electric Heating Home	1	0.08870	0.00300	29.53	<.0001
D_Reg_SI	Dummy Variable of Region: Southern Interior	1	-0.04914	0.00372	-13.22	<.0001
D_Reg_N	Dummy Variable of Region: North	1	-0.02525	0.00370	-6.83	<.0001
D_APT	Dummy Variable of Dwell Type: Apartment	1	-0.75585	0.01928	-39.21	<.0001
D_ROW	Dummy Variable of Dwell Type: Row House	1	-0.29618	0.01240	-23.89	<.0001
D_MOB	Dummy Variable of Dwell Type: Mobile Home	1	-0.10879	0.00623	-17.47	<.0001
ln_P1	Natural Logarithm of Step 1 Price	1	-0.14448	0.02201	-6.56	<.0001
C_small	correction term: small customers	1	0.18021	0.01051	17.15	<.0001

Model 2

Basic functional form:

$$\ln(Consumption) = \alpha + \beta \cdot Heat + \gamma \cdot Dwelling + \delta \cdot BillingPeriod + \omega 1 \cdot CDD + \omega 2 \cdot HDD$$

$$+ \mathfrak{z} \cdot Region + \theta \cdot \ln\left(DSM_{Expenditure}\right) + \varepsilon \cdot \ln(Price)$$

$$+ \sigma \cdot ln\,(Disposable\_Income) + \varphi \cdot C + \mu$$

This model tests whether adding DSM expenditure will affect the estimate of price elasticity or the coefficients of other variables.

Step 1 price elasticity is estimated at -0.14 in model 2 where BC Hydro's DSM expenditure is added in the equation. This Step 1 price elasticity result is close to the step 1 price elasticity estimate from Model 1. The results from model 2 show that DSM expenditure is not a statistically significant variable with its coefficient associated with a wrong sign and a large p-value. Adding DSM expenditure in the model only affects the coefficient estimates in a very minor way as compared to the results from model 1. These results suggest omitting DSM expenditures from the model used to estimate price elasticity does not introduce meaningful levels of uncertainty or error.

Root MSE	0.07356	*R-Square*	0.8614
Dependent Mean	6.64328	*Adj R-Sq*	0.8606
Coeff Var	1.10734		

Parameter Estimates

Variable	*Label*	*DF*	*Parameter Estimate*	*Standard Error*	*t Value*	*Pr > |t|*
Intercept	Intercept	1	6.82761	0.07129	95.77	<.0001
BP_1	Billing Period Apr-May	1	-0.09056	0.00712	-12.72	<.0001
BP_2	Billing Period Jun-Jul	1	-0.17525	0.00974	-17.99	<.0001
BP_3	Billing Period Aug-Sep	1	-0.13506	0.00910	-14.84	<.0001
BP_4	Billing Period Oct-Nov	1	0.02967	0.00531	5.58	<.0001
BP_5	Billing Period Dec-Jan	1	0.09203	0.00665	13.85	<.0001
D_heat_elec	Dummy Variable: Electric Heating Home	1	0.08870	0.00300	29.54	<.0001
D_Reg_SI	Dummy Variable of Region: Southern Interior	1	-0.04914	0.00372	-13.23	<.0001
D_Reg_N	Dummy Variable of Region: North	1	-0.02525	0.00369	-6.83	<.0001
D_APT	Dummy Variable of Dwell Tyep: Appartment Building	1	-0.75585	0.01928	-39.21	<.0001
D_ROW	Dummy Variable of Dwell Tyep: Row House	1	-0.29618	0.01240	-23.89	<.0001
D_MOB	Dummy Variable of Dwell Tyep: Mobile Home	1	-0.10879	0.00623	-17.47	<.0001
ln_P1	Natural Logrithm of Step 1 Price	1	-0.13562	0.02323	-5.84	<.0001
Ln_DSM_Acct_Bimonth_MovAvg6	12-month moving average of DSM expenditures	1	0.00515	0.00431	1.20	0.2321
C_small	correction term: small customers	1	0.18021	0.01051	17.15	<.0001

Model 3

Basic functional form:

$$\ln(Consumption + DSM\ Savings) = \alpha + \beta \cdot Heat + \gamma \cdot Dwelling + \delta \cdot BillingPeriod + \omega 1 \cdot CDD + \omega 2 \cdot HDD + \mathfrak{z} \cdot Region + \varepsilon \cdot \ln(Price) + \sigma \ln(Disposable_{Income}) + \varphi \cdot C + \mu$$

When DSM savings were added to Step 1 electricity consumption, a statistically significant estimate of Step 1 price elasticity of -0.17 was found. This estimate is related to electricity consumption in the absence of conservation effects, therefore the price elasticity estimate in this way encompasses conservation effects generated by other DSM initiatives. In light of the conflicting result from model 2, which indicated that DSM expenditure was not a valid variable and did not affect the Step 1 elasticity estimate, it is difficult to determine how DSM initiatives affect the Step 1 elasticity estimate. The elasticity estimate from model 3 contains some DSM conservation impact in addition to price impact and is deemed not to be a true estimate of the Step 1 price elasticity.

Root MSE	0.07422	R-Square	0.8502
Dependent Mean	6.67838	Adj R-Sq	0.8494
Coeff Var	1.11132		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	6.72860	0.06922	97.20	<.0001
BP_1	Billing Period Apr-May	1	-0.05312	0.00718	-7.39	<.0001
BP_2	Billing Period Jun-Jul	1	-0.16727	0.00983	-17.02	<.0001
BP_3	Billing Period Aug-Sep	1	-0.13079	0.00918	-14.24	<.0001
BP_4	Billing Period Oct-Nov	1	0.02991	0.00536	5.58	<.0001
BP_5	Billing Period Dec-Jan	1	0.09367	0.00670	13.97	<.0001
D_heat_elec	Dummy Variable: Electric Heating Home	1	0.08502	0.00303	28.06	<.0001
D_Reg_SI	Dummy Variable of Region: Southern Interior	1	-0.04761	0.00375	-12.70	<.0001
D_Reg_N	Dummy Variable of Region: North	1	-0.02449	0.00373	-6.57	<.0001
D_APT	Dummy Variable of Dwell Type: Apartment Building	1	-0.72714	0.01945	-37.39	<.0001
D_ROW	Dummy Variable of Dwell Type: Row House	1	-0.28540	0.01251	-22.82	<.0001
D_MOB	Dummy Variable of Dwell Type: Mobile Home	1	-0.10497	0.00628	-16.71	<.0001
ln_P1	Natural Logarithm of Step 1 Price	1	-0.17351	0.02221	-7.81	<.0001
C_small	correction term: small customers	1	0.17327	0.01060	16.35	<.0001

Step 2 Price Elasticity

Model 1

Basic functional form:

$$\ln(Consumption) = \alpha + \beta \cdot Heat + \gamma \cdot Dwelling + \delta \cdot BillingPeriod + \omega 1 \cdot CDD + \omega 2 \cdot HDD$$

$$+ \mathfrak{z} \cdot Region + \varepsilon \cdot ln\,(Price) + \sigma \cdot ln\,(Disposable\_Income) + \varphi \cdot C + \mu$$

Step 2 price elasticity is estimated at -0.08.

Root MSE	0.11614	R-Square	0.7743
Dependent Mean	7.75960	Adj R-Sq	0.7729
Coeff Var	1.49679		

Parameter Estimates						
Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	6.33105	0.60970	10.38	<.0001
BP_1	Billing Period Apr-May	1	-0.17791	0.00832	-21.37	<.0001
BP_2	Billing Period Jun-Jul	1	-0.26376	0.00840	-31.41	<.0001
BP_3	Billing Period Aug-Sep	1	-0.25692	0.00837	-30.69	<.0001
BP_4	Billing Period Oct-Nov	1	-0.06819	0.00854	-7.98	<.0001
BP_5	Billing Period Dec-Jan	1	0.11526	0.00839	13.74	<.0001
D_heat_elec	Dummy Variable: Electric Heating Home	1	0.17665	0.00496	35.64	<.0001
D_Reg_SI	Dummy Variable of Region: Southern Interior	1	0.02087	0.00581	3.59	0.0003
D_Reg_N	Dummy Variable of Region: North	1	0.01811	0.00583	3.11	0.0019
D_APT	Dummy Variable of Dwell Type: Apartment Building	1	-0.33510	0.00671	-49.97	<.0001
D_ROW	Dummy Variable of Dwell Type: Row House	1	-0.28197	0.00671	-42.05	<.0001
D_MOB	Dummy Variable of Dwell Type: Mobile Home	1	-0.10968	0.00671	-16.36	<.0001
HDD	HDD	1	-0.00007054	0.00001637	-4.31	<.0001
D_ELEC_HDD	Interaction Term of Electric Heating Home and HDD	1	0.00010742	0.00002130	5.04	<.0001
ln_income	Natural Logarithm of Disposable Income	1	0.13785	0.05459	2.53	0.0116
ln_P2	Natural Logarithm of Step 2 Price	1	-0.08151	0.02169	-3.76	0.0002
C_large	correction term: large customers	1	-0.20262	0.01881	-10.77	<.0001

Model 2

Basic functional form:

$$\ln(Consumption) = \alpha + \beta \cdot Heat + \gamma \cdot Premise + \delta \cdot BillingPeriod + \omega 1 \cdot CDD + \omega 2 \cdot HDD$$

$$+ \mathfrak{z} \cdot Region + \theta \cdot \ln\left(DSM_{Expenditure}\right) + \varepsilon \cdot \ln(Price)$$

$$+ \sigma \cdot \ln(Disposable_{Income}) + \varphi \cdot C + \mu$$

DSM expenditures were included in Model 2, and resulted in a Step 2 price elasticity estimate of -0.10. However, the coefficient for DSM expenditures had a positive sign which indicated that increasing DSM expenditures added to electricity consumption. This is counter-intuitive and may be due to the reduction in BC Hydro's DSM expenditures in recent years that correspond to the general trend of the reduction in Step 2 price response. The positive coefficient for DSM expenditures affects the coefficients of other variables, meaning the Step 2 price elasticity from model 2 is not considered to be a true estimate of Step 2 price elasticity.

Root MSE	0. 11593	R-Square	0. 7753
Dependent Mean	7. 75960	Adj R-Sq	0. 7737
Coeff Var	1. 49406		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	6.11178	0.59563	10.26	<.0001
BP_1	Billing Period Apr-May	1	-0.27106	0.01196	-22.66	<.0001
BP_2	Billing Period Jun-Jul	1	-0.44805	0.01906	-23.50	<.0001
BP_3	Billing Period Aug-Sep	1	-0.41811	0.01714	-24.39	<.0001
BP_4	Billing Period Oct-Nov	1	-0.06827	0.00833	-8.20	<.0001
BP_5	Billing Period Dec-Jan	1	0.17350	0.00979	17.71	<.0001
D_heat_elec	Dummy Variable: Electric Heating Home	1	0.17665	0.00483	36.56	<.0001
D_Reg_SI	Dummy Variable of Region: Southern Interior	1	0.00989	0.00575	1.72	0.0857
D_Reg_N	Dummy Variable of Region: North	1	0.02514	0.00572	4.39	<.0001
D_APT	Dummy Variable of Dwell Type: Apartment Building	1	-0.78249	0.04197	-18.64	<.0001
D_ROW	Dummy Variable of Dwell Type: Row House	1	-0.47079	0.01868	-25.21	<.0001
D_MOB	Dummy Variable of Dwell Type: Mobile Home	1	-0.16621	0.00838	-19.84	<.0001
HDD	HDD	1	-0.00006274	0.00001613	-3.89	0.0001
D_ELEC_HDD1	Interaction Term of Electric Heating Home and HDD	1	0.00010742	0.00002077	5.17	<.0001
ln_income	Natural Logarithm of Disposable Income	1	0.14455	0.05326	2.71	0.0067
ln_P2	Natural Logarithm of Step 2 Price	1	-0.09919	0.02185	-4.54	<.0001
Ln_DSM_Acct_Bimonth_MovAvg6	Natural Logarithm of Bimonthly DSM expenditure of 6-period Moving Average	1	0.02303	0.00721	3.19	0.0014
C_large	correction term: large customers	1	-0.20265	0.01878	-10.79	<.0001

Model 3

Basic functional form:

$$\ln(Consumption + DSM\ Savings) = \alpha + \beta \cdot Heat + \gamma \cdot Dwelling + \delta \cdot BillingPeriod + \omega 1 \cdot CDD + \omega 2 \cdot HDD + \mathfrak{z} \cdot Region + \varepsilon \cdot \ln(Price) + \sigma \ln(Disposable_{Income}) + \varphi \cdot C + \mu$$

When DSM savings were added to Step 2 electricity consumption, a statistically significant estimate of Step 2 price elasticity of -0.08 was found. This estimate is close to the result from Model 1, which indicates that the inclusion of DSM savings in the model had little impact on the Step 2 price elasticity estimate. This may be attributed to relatively small changes in DSM savings as compared to Step 2 consumption.

Root MSE	0.11561	R-Square	0.7721
Dependent Mean	7.77140	Adj R-Sq	0.7707
Coeff Var	1.48764		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	6.61386	0.59272	11.16	<.0001
BP_1	Billing Period Apr-May	1	-0.25987	0.01192	-21.80	<.0001
BP_2	Billing Period Jun-Jul	1	-0.44760	0.01900	-23.55	<.0001
BP_3	Billing Period Aug-Sep	1	-0.41860	0.01709	-24.50	<.0001
BP_4	Billing Period Oct-Nov	1	-0.06839	0.00830	-8.24	<.0001
BP_5	Billing Period Dec-Jan	1	0.17383	0.00977	17.80	<.0001
D_heat_elec	Dummy Variable: Electric Heating Home	1	0.17500	0.00482	36.32	<.0001
D_Reg_SI	Dummy Variable of Region: Southern Interior	1	0.00986	0.00574	1.72	0.0857
D_Reg_N	Dummy Variable of Region: North	1	0.02530	0.00571	4.43	<.0001
D_APT	Dummy Variable of Dwell Type: Apartment Building	1	-0.77869	0.04185	-18.61	<.0001
D_ROW	Dummy Variable of Dwell Type: Row House	1	-0.46767	0.01862	-25.11	<.0001
D_MOB	Dummy Variable of Dwell Type: Mobile Home	1	-0.16519	0.00835	-19.78	<.0001
HDD	HDD	1	-0.00006929	0.00001591	-4.36	<.0001
D_ELEC_HDD1	Interaction Term of Electric Heating Home and HDD	1	0.00010447	0.00002071	5.05	<.0001
ln_income	Natural Logrithm of Disposable Income	1	0.10323	0.05307	1.95	0.0519
ln_P2	Natural Logrithm of Step 2 Price	1	-0.07646	0.02108	-3.63	0.0003
C_large	correction term: large customers	1	-0.20251	0.01872	-10.82	<.0001

Analysis of Price Elasticity in New Westminster

The analysis of price elasticity of about 32,000 customers in New Westminster was conducted to estimate the flat rate elasticity as a proxy for BC Hydro's flat rate elasticity. The analysis covered the period from 2005 to 2016. The elasticity analysis was built on an average bi-monthly consumption model which incorporated customer data and information available to BC Hydro.

The specific model is as follows:

$$\ln(Consumption) = \alpha + \beta \cdot HeatingCode + \gamma \cdot Premise + \delta \cdot BillingPeriod + \omega 1 \cdot CDD + \omega 2 \cdot HDD$$
$$+ \varepsilon \cdot ln\,(Price) + \sigma \cdot ln\,(Income) + \mu$$

where

ln() denotes natural logarithm;

Consumption: is the average bi-monthly consumption per account in kWh;

HeatingCode: is a binary indicator (dummy variable) whose value is one to indicate the presence or zero to indicate absence of electricity as the primary space heating fuel;

Premise: represents single detached home, high-rise building, Multiple Apartment Block, and condominium;

BillingPeriod: contains six bi-monthly billing periods which are represented by BP_1, BP_2, … and BP_5 in the model output (the default period is BP_6);

CDD and HDD: represent cooling and heating degree days, respectively, which are used to represent weather impacts;

Price: electricity price (CPI-adjusted);

Income: personal disposable income (CPI-adjusted);

μ *is the error term.*

The modelling results as shown below indicate that price, income and billing period 5 were not statistically significant variables in the model.

Root MSE	0.19857	R-Square	0.9209
Dependent Mean	6.70386	Adj R-Sq	0.9189
Coeff Var	2.96205		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	9.92135	6.16729	1.61	0.1083
Ln_Price	Natural log of Electricity price adjusted by CPI	1	-0.04068	0.11153	-0.36	0.7154
Ln_income	Natural log of personal real income	1	-0.30442	0.56294	-0.54	0.5889
BP_1	Billing Period Apr-May	1	0.22477	0.06090	3.69	0.0002
BP_2	Billing Period Jun-Jul	1	0.37166	0.11746	3.16	0.0016
BP_3	Billing Period Aug-Sep	1	0.33562	0.11527	2.91	0.0038
BP_4	Billing Period Oct-Nov	1	0.11727	0.03729	3.14	0.0018
BP_5	Billing Period Dec-Jan	1	-0.03511	0.04437	-0.79	0.4292
CDD	Cooling degree days	1	0.00598	0.00200	2.99	0.0030
HDD	Heating degree days	1	0.00118	0.00019	6.09	<.0001
Heating_Code	Electricity as primary heating fuel	1	0.31938	0.01728	18.48	<.0001
D_Highrise	Dwelling Type: Highrise building	1	-1.55798	0.02444	-63.74	<.0001
D_Multi	Dwelling Type: Multiple Apartment Block	1	-1.49089	0.02444	-61.00	<.0001
D_Strata	Dwelling Type: Strata-Condominium	1	-0.92860	0.02444	-37.99	<.0001

When these invalid variables except for the price are excluded from the model, the result of price elasticity is -0.10, as shown in the next table. However, it was not statistically significant at the 90 percent confidence level.

Root MSE	0.19835	R-Square	0.9207
Dependent Mean	6.70386	Adj R-Sq	0.9190
Coeff Var	2.95878		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	6.61248	0.18357	36.02	<.0001
Ln_Price	Natural log of Electricity price adjusted by CPI	1	-0.10274	0.06733	-1.53	0.1276
BP_1	Billing period: April and May	1	0.19979	0.05332	3.75	0.0002
BP_2	Billing Period Aug-Sep	1	0.31097	0.09192	3.38	0.0008
BP_3	Billing Period Oct-Nov	1	0.27583	0.08991	3.07	0.0023
BP_4	Billing Period Dec-Jan	1	0.11133	0.03666	3.04	0.0025
CDD	Cooling degree days	1	0.00573	0.00198	2.89	0.0040
HDD	Heating degree days	1	0.00106	0.00014	8.16	<.0001
Heating_Code	Electricity as primary heating fuel	1	0.31938	0.01726	18.50	<.0001
D_Highrise	Dwelling Type: Highrise building	1	-1.55798	0.02442	-63.81	<.0001
D_Multi	Dwelling Type: Multiple Apartment Block	1	-1.49089	0.02442	-61.06	<.0001
D_Strata	Dwelling Type: Strata-Condominium	1	-0.92860	0.02442	-38.03	<.0001

Analysis of Step 1 Price Elasticity in 2016

Following the 2013 RIB Evaluation, Step 1 price elasticity was analysed again in 2016 with additional data for F2013 to F2015. The data series covered F2005 to F2015. This work is referred to as Round 2 analysis in Section 3 of this Report. This analysis applied the same model used in the 2013 RIB Evaluation, which has the following functional form:

$$\ln(Consumption) = \alpha + \beta \cdot Heat + \gamma \cdot Dwelling + \delta \cdot BillingPeriod + \omega 1 \cdot CDD + \omega 2 \cdot HDD$$
$$+ \mathfrak{z} \cdot Region + \varepsilon \cdot ln\,(Price) + \sigma \cdot ln\,(Disposable\_Income) + \varphi \cdot C + \mu$$

The estimated Step 1 price elasticity was not statistically significant (*p*=0.5721).

Root MSE	0.02968	R-Square	0.9735
Dependent Mean	6.67393	Adj R-Sq	0.9731
Coeff Var	0.42978		

Parameter Estimates

Variable	**Label**	**DF**	**Parameter Estimate**	**Standard Error**	**t Value**	**Pr > |t|**
Intercept	Intercept	1	7.51364	0.13130	57.22	<.0001
BP_1	Billing period: April and May	1	-0.05611	0.00483	-11.62	<.0001
BP_2	Billing period: June and July	1	-0.13709	0.00780	-17.59	<.0001
BP_3	Billing Period: Aug-Sep	1	-0.09863	0.00711	-13.88	<.0001
BP_4	Billing Period: Oct-Nov	1	0.02288	0.00330	6.94	<.0001
BP_5	Billing Period: Dec-Jan	1	0.06879	0.00389	17.70	<.0001
D_Reg_N	Dummy Variable of Region: North	1	-0.04957	0.00333	-14.90	<.0001
D_Reg_SI	Dummy Variable of Region: Southern Interior	1	-0.07260	0.00302	-24.05	<.0001
D_Reg_VI	Dummy Variable of Region: Vanouver Island	1	0.05999	0.00389	15.44	<.0001
D_APT	Dummy Variable of Dwell Type: Apartment Building	1	-0.67598	0.01154	-58.60	<.0001
D_ROW	Dummy Variable of Dwell Type: Row House	1	-0.24943	0.00677	-36.82	<.0001
D_MOB	Dummy Variable of Dwell Type: Mobile Home	1	-0.09079	0.00324	-28.00	<.0001
CDD	Cooling degree days	1	0.00046	0.000035	13.08	<.0001
HDD	Heating degree days	1	0.00006	0.000006	10.05	<.0001
ln_P1	Natural Logarithm of Step 2 Price	1	-0.02071	0.03069	-0.68	0.5721
ln_income	Natural Logarithm of Disposable Income	1	-0.06388	0.01090	-5.86	<.0001
C_small	correction term: small customers	1	0.17246	0.00789	21.85	<.0001

D.2. Additional Customer Insights in Relation to the RIB Rate

This section provides more detail on customers' consumption of electricity in F2017, their opinions toward their household's consumption, the price of electricity and accompanying bills, and their awareness and attitudes toward the RIB rate.

D.2.1. Customer Exposure to Step 2 Electricity Consumption

Incidence of Step 2 Electricity Consumption by Space Heating and Water Heating Fuels

Section 3.4.1 showed that customer households on Vancouver Island and those living in single detached houses were the most likely of all customers to have incurred Step 2 electricity consumption in F2017.

The incidence of having incurred Step 2 consumption in at least one month of F2017 measured evenly at 69 percent among households that primarily rely on electricity for space heating and among those that rely on non-electric fuels such as natural gas, oil or propane.

In terms of water heating fuel, the incidence of having incurred Step 2 consumption in at least one month of F2017 measured 87 percent among households that have electric hot water heaters, 75 percent among those that have non-electric hot water heaters, and just 31 percent among those who rely on hot water from a central system. The relationship is underscored by the wide differences in the proportion of these three groups that always incurred Step 2 consumption in all twelve months of the fiscal year, measuring 33 percent, 24 percent and 1 percent, respectively.

Table D.2.1: Incidence of Step 2 Electricity Consumption in F2017 by Space Heating and Water Heating Fuels

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total	Total Sometimes + Always into Step 2
Total	30%	48%	22%	100%	70%
Main Space Heating Fuel					
Electricity	31%	50%	18%	100%	69%
Non-Electric	31%	45%	24%	100%	69%
Main Water Heating Fuel					
Electricity	13%	55%	33%	100%	87%
Non-Electric	25%	51%	24%	100%	75%
No hot water tank (central)	69%	30%	1%	100%	31%
Main Space Heating and Water Heating Fuels					
Electric Heating & Electric Water	11%	59%	30%	100%	89%
Electric Heating & Non-Electric Water	15%	57%	27%	100%	85%
Electric Heating & Central Water	62%	37%	1%	100%	38%
Non-Electric Heating & Electric Water	16%	46%	39%	100%	84%
Non-Electric Heating & Non-Electric Water	26%	50%	23%	100%	74%
Non-Electric Heating & Central Water	89%	9%	2%	100%	11%

Row totals may not total 100% due to the rounding of values.

Based on the magnitude of observed differences, it may first appear that water heating fuel was a stronger determinant of Step 2 status than space heating fuel. However, there are direct and indirect interactions between the two end-uses – as well as with other housing characteristics – that must be understood.

First, electrically heated homes are comprised of a much larger share of apartments and condominiums relying on electric baseboards. These dwellings are typically much smaller in size compared to other dwellings, lower in occupancy, have shared walls, and importantly, predominantly rely on central water heating. Second, a majority of households with electric hot water heaters also have electric space heating.

When looked at in isolation, electric space heating – in the absence of electric water heating – has a similar impact on the incidence of Step 2 consumption as does the impact of electric water heating in the absence of electric space heating. In these isolated scenarios, however, the homes with electric space heating would likely incur more Step 2 consumption in the heating season – and possibly the shoulder seasons – compared to homes with electric water heating.

Note that the incidence of having incurred Step 2 consumption climbed only marginally to 89 percent for homes that have both electric space heating and electric water heating – likely because most of these homes would already breach the threshold with only one of the two electric end-uses. However, these homes would likely incur more Step 2 consumption than those that had just one of the two electric end-uses.

Incidence of Step 2 Electricity Consumption by Household Demographics

Customers living in single detached houses have already been shown in Section 3.4.1 to have been among the most likely to have incurred Step 2 consumption in at least one month of F2017. Given the comparably higher cost of these homes and their comparably larger size, it comes expectedly that customers who own their homes, who have higher household incomes and who have the most household occupants are all among the most likely to have incurred Step 2 consumption during the year.

Table D.2.2: Incidence of Step 2 Electricity Consumption in F2017 by Household Demographics

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total	Total Sometimes + Always into Step 2
Total	30%	48%	22%	100%	70%
Home Ownership					
Own/Co-op	24%	51%	24%	100%	76%
Rent	61%	30%	10%	100%	39%
Number of Household Occupants					
1	57%	40%	3%	100%	43%
2	30%	54%	15%	100%	70%
3	18%	53%	29%	100%	82%
4 +	13%	40%	46%	100%	87%
Household Income					
Under $40,000	46%	43%	10%	100%	54%
$40,000 < $80,000	35%	48%	18%	100%	65%
$80,000 < $120,000	24%	51%	25%	100%	76%
$120,000 +	18%	50%	32%	100%	82%
Low Income Status					
Yes, 'low income' household	46%	41%	13%	100%	54%
No	30%	48%	22%	100%	70%

Row totals may not total 100% due to the rounding of values.

D.2.2. Consumption Profiles by the Incidence of Step 2 Electricity Consumption

This section presents electricity consumption patterns and insights essentially in reverse of the way presented in the previous section of this appendix. Instead of exploring customer sub-groups as to how their consumption distributes into the three unique consumption bins, each of the three consumption bins are explored as to how customer sub-groups distribute within them. Specifically, the tables detail the profiles of customer households that never (0 months), sometimes (1-11 months) and always (12 months) incurred Step 2 consumption in the twelve months of F2017.

Profile of Region and Dwelling Type by the Incidence of Step 2 Electricity Consumption

The profile of residential customers that never incurred Step 2 consumption in the twelve months of F2017 was comprised of some 70 percent of Lower Mainland households, due in large part to the greater proportion of apartments and condominiums in the region and the fact they tend to use less electricity than all other dwelling types. In fact, apartments and condominiums had a 59 percent share of all dwellings that never incurred Step 2 consumption in F2017 – 31 points higher than their overall share of dwellings in BC Hydro's service territory. Related, nearly one-half of these customers were single occupant households.

Given the breadth of the consumption bin, it comes expectedly that the profile of residential customers that sometimes incurred Step 2 consumption in F2017 generally followed that of the overall customer base.

Table D.2.3: Profile of Region and Dwelling Type by the Incidence of Step 2 Consumption in F2017

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	All Customers
Region				
Lower Mainland	70%	55%	51%	59%
Vancouver Island	15%	23%	26%	21%
Southern Interior	9%	13%	13%	12%
North	6%	9%	9%	8%
Total	100%	100%	100%	100%
Dwelling Type				
Single detached house	29%	57%	86%	54%
Duplex/Row house/townhouse	9%	17%	8%	13%
Apartment/Condominium	59%	20%	2%	28%
Mobile home/other	4%	6%	4%	5%
Total	100%	100%	100%	100%

Column totals may not total 100% due to the rounding of values.

The pool of residential customers that always incurred Step 2 consumption in F2017 was comprised of a somewhat greater share of households outside the Lower Mainland – especially on Vancouver island – as compared to their share in the population overall. This consumption bin, however, was more prominently characterized by its dwelling composition by virtue of the fact that 86 percent were single detached houses – 32 points higher than their 54 percent share across the entire service territory.

Profile of Space Heating and Water Heating Fuels by the Incidence of Step 2 Electricity Consumption

The profile of households that never incurred Step 2 consumption in the twelve months of F2017 was largely comprised of households that do not rely on electricity for either of their space heating or water heating needs.

As for households that always incurred Step 2 consumption, the share of main space heating fuels measured 39 percent electric and 61 percent non-electric. This group's profile by water heating fuel does not follow that of the overall population as it is 18 points over-represented by households with electric hot water tanks (53%) and 23 points under-represented by households without any hot water tanks at all (1%). As detailed in this appendix, these findings reflect a complex interplay of factors that influence customer exposure to Step 1 and 2 prices, including space heating, water heating, dwelling and other demographic parameters.

Table D.2.4: Profile of Space and Water Heating Fuels by the Incidence of Step 2 Consumption in F2017

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	All Customers
Main Space Heating Fuel				
Electricity	46%	48%	39%	45%
Non-Electric	54%	52%	61%	55%
Total	100%	100%	100%	100%
Main Water Heating Fuel				
Electricity	14%	41%	53%	35%
Non-Electric	33%	44%	45%	41%
No hot water tank (central)	53%	15%	1%	24%
Total	100%	100%	100%	100%
Main Space Heating and Water Heating Fuels				
Electric Heating & Electric Water	8%	29%	32%	23%
Electric Heating & Non-Electric Water	2%	5%	5%	4%
Electric Heating & Central Water	35%	14%	1%	18%
Non-Electric Heating & Electric Water	6%	11%	21%	12%
Non-Electric Heating & Non-Electric Water	31%	39%	40%	37%
Non-Electric Heating & Central Water	18%	1%	<1%	6%
Total	100%	100%	100%	100%

Column totals may not total 100% due to the rounding of values.

Profile of Household Demographics by the Incidence of Step 2 Electricity Consumption

Compared to the population of all residential customers, households that always incurred Step 2 consumption in F2017 were more likely to own their homes (91% versus 81% overall) and to have reported annual earnings of at least $80,000 (60% versus 44% overall). These findings simply reflect the fact that this consumption bin is largely comprised of single detached houses.

Table D.2.5: Profile of Household Demographics by the Incidence of Step 2 Consumption in F2017

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	All Customers
Home Ownership				
Own/Co-op	63%	88%	91%	81%
Rent	37%	12%	9%	19%
Total	100%	100%	100%	100%
Number of Household Occupants				
1	43%	19%	4%	23%
2	39%	45%	28%	40%
3	8%	15%	17%	13%
4 +	11%	21%	52%	24%
Total	100%	100%	100%	100%
Household Income				
Under $40,000	36%	22%	13%	25%
$40,000 < $80,000	34%	31%	27%	31%
$80,000 < $120,000	18%	26%	30%	24%
$120,000 +	11%	20%	30%	20%
Total	100%	100%	100%	100%
Low Income Status				
Yes, 'low income' household	16%	10%	7%	11%
No	84%	90%	93%	89%
Total	100%	100%	100%	100%

Column totals may not total 100% due to the rounding of values.

D.2.3. Customer Opinions about Managing Electricity Consumption

This section presents findings in regards to customers' opinions around managing their consumption of electricity, including their reported ease of doing so, their current effort and their change in effort over the past three years.

Ease in Managing Household Electricity Consumption

As a way to 'ease' customer respondents into the rates-related content of the 2017 survey, they were first queried about the management of their household's electricity use. Customers were reminded that they can manage their consumption of electricity by changing behaviour, purchasing energy-efficient products, making energy-efficient home upgrades and by participating in conservation programs.

Under the premise that they want to manage their use of electricity, a total of 75 percent of customers reported that it is either 'very easy' or 'somewhat easy' for them to manage their use of electricity. As detailed in Table D.2.6, this proportion measured 84 percent among customers who never incurred Step 2 electricity consumption in F2017, 74 percent among customers who sometimes incurred Step 2 electricity consumption and 64 percent among those who always did so.

Table D.2.6: Reported Ease or Difficulty in Managing Household Electricity Consumption

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total
Total very easy + somewhat easy	84%	74%	64%	75%
Very easy	34%	20%	14%	23%
Somewhat easy	50%	54%	50%	52%
Somewhat difficult	13%	22%	31%	21%
Very difficult	2%	4%	5%	4%
Total	100%	100%	100%	100%

Column totals may not total 100% due to the rounding of values.
Don't know responses have been excluded from all calculations.

Current Effort in Managing Household Electricity Consumption

A total of 67 percent of customers in the 2017 survey reported that their household was currently making either 'a great deal of effort' or 'a fair amount of effort' to manage its consumption of electricity.

Table D.2.7: Reported Effort in Managing Household Electricity Consumption

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total
Total a great deal of effort + a fair amount effort	67%	68%	65%	67%
A great deal of effort	17%	14%	12%	14%
A fair amount of effort	50%	53%	53%	52%
A little effort	26%	28%	32%	28%
No effort at all	6%	3%	2%	4%
Not applicable – there is little opportunity to do so	1%	1%	1%	1%
Total	100%	100%	100%	100%

Column totals may not total 100% due to the rounding of values.
Don't know responses have been excluded from all calculations.

Change in Effort over the Past Three Years in Managing Household Electricity Consumption

The majority of customer households – 57 percent – reported that they were currently making either 'much more of an effort' or 'a little more of an effort' to manage their consumption of electricity as compared to three years ago. This proportion measured lowest at 49 percent among customers who never incurred Step 2 electricity consumption in F2017 and highest at 63 percent among those who always did so.

Table D.2.8: Reported Change in Effort over the Past Three Years in Managing Electricity Consumption

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total
Total much more of an effort + a little more of an effort	49%	60%	63%	57%
Much more of an effort	16%	20%	21%	19%
A little more of an effort	33%	40%	42%	38%
No change	49%	37%	34%	40%
A little less of an effort	2%	2%	3%	2%
Much less of an effort	<1%	<1%	<1%	<1%
Total	100%	100%	100%	100%

Column totals may not total 100% due to the rounding of values.
Don't know responses have been excluded from all calculations.

D.2.4. Customer Opinions about Electricity Prices and their Bills

This section presents additional findings in regards to customers' opinions around their perceived price of electricity and their accompanying bills.

Electricity Prices – Value for Money

Customer respondents in the 2017 survey were asked to think about the amount of money their household pays for electricity every month, every two months or even over the course of a year, and to consider the benefits they receive in return. In total, 79 percent of customers believed that the amount of money represents either 'excellent', 'good' or 'fair' value for money. Customer opinions in this regard varied strongly with their Step 2 consumption status in F2017, measuring highest at 90 percent among customers who never incurred Step 2 electricity consumption in F2017 and lowest 67 percent among those who always did so.

Table D.2.9: Perceived Value for Money Household Pays for its Electricity Consumption

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total
Total excellent + good + fair	90%	77%	67%	79%
Excellent value for money	12%	4%	2%	6%
Good value for money	31%	22%	14%	23%
Fair value for money	46%	52%	51%	50%
Poor value for money	5%	16%	24%	14%
Very poor value for money	1%	3%	5%	3%
Don't know	4%	4%	4%	4%
Total	100%	100%	100%	100%

Column totals may not total 100% due to the rounding of values.

Total Electricity Bill

The majority of customers in the 2017 survey reported that they look over their household's electricity bill either 'at least once a month' or 'once every two months'.

Table D.2.10: Frequency of Looking over Electricity Bill (Print or Online Version)

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total
Total at least once a month + once every 2 months	78%	80%	81%	80%
At least once a month	36%	40%	39%	39%
Once every 2 months	42%	40%	43%	41%
Once every 3 months	5%	6%	5%	6%
Once every 4 to 6 months	4%	4%	4%	4%
Once or twice a year	4%	5%	4%	4%
Never – we just pay it	8%	5%	5%	6%
Total	100%	100%	100%	100%

Column totals may not total 100% due to the rounding of values.
Don't know responses have been excluded from all calculations.

Attitudes toward Household Electricity Consumption and Bills

Table D.2.11 below details customer agreement levels on four attitudinal statements related to their household's electricity consumption and the accompanying electricity bills.

Table D.2.11: Attitudes toward Household Electricity Consumption and Bills (Table 1 of 2)

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total
I spend more time looking over bills I receive than my BC Hydro bill				
Total strongly agree + somewhat agree	38%	32%	27%	33%
Strongly agree	16%	14%	13%	14%
Somewhat agree	21%	18%	14%	18%
Neither agree nor disagree	30%	32%	40%	33%
Somewhat disagree	18%	21%	16%	19%
Strongly disagree	13%	14%	16%	14%
Don't know	1%	1%	1%	1%
Total	100%	100%	100%	100%
I have a good understanding of the factors that cause changes in my household's electricity consumption				
Total strongly agree + somewhat agree	48%	51%	50%	50%
Strongly agree	22%	21%	18%	21%
Somewhat agree	25%	30%	32%	29%
Neither agree nor disagree	11%	8%	11%	10%
Somewhat disagree	23%	26%	24%	24%
Strongly disagree	16%	13%	14%	14%
Don't know	2%	2%	1%	2%
Total	100%	100%	100%	100%

Column totals may not total 100% due to the rounding of values.

Table D.2.12: Attitudes toward Household Electricity Consumption and Bills (Table 2 of 2)

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total
My BC Hydro bill is easy to understand				
Total strongly agree + somewhat agree	52%	47%	50%	49%
Strongly agree	20%	16%	15%	17%
Somewhat agree	32%	31%	34%	32%
Neither agree nor disagree	11%	16%	15%	14%
Somewhat disagree	22%	24%	25%	24%
Strongly disagree	13%	12%	10%	12%
Don't know	2%	1%	<1%	1%
Total	100%	100%	100%	100%
I usually pay my BC Hydro bill without looking over its consumption levels				
Total strongly agree + somewhat agree	45%	42%	42%	43%
Strongly agree	23%	22%	23%	22%
Somewhat agree	22%	20%	19%	21%
Neither agree nor disagree	9%	9%	11%	10%
Somewhat disagree	22%	22%	22%	22%
Strongly disagree	23%	27%	25%	25%
Don't know	<1%	<1%	<1%	<1%
Total	100%	100%	100%	100%

Column totals may not total 100% due to the rounding of values.

Reported Change in Total Electricity Bill Amounts

A total of 79 percent of customers believed that the total dollar amount of their electricity bills have either 'increased a great deal' or 'increased just a little' over the past three years. This proportion stepped up through the three consumption bins, from a low of 69 percent among customers who never incurred Step 2 electricity consumption in F2017 to a high of 86 percent among those who always did so.

Table D.2.13: Reported Change in Total Electricity Bill Amounts over the Past Three Years

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total
Total increased a great deal + increased just a little	69%	81%	86%	79%
Increased a great deal	16%	34%	46%	31%
Increased just a little	54%	47%	40%	48%
Stayed about the same	20%	10%	7%	12%
Decreased just a little	2%	3%	2%	3%
Decreased a great deal	1%	1%	1%	1%
Don't know	8%	5%	4%	5%
Total	100%	100%	100%	100%

Column totals may not total 100% due to the rounding of values.

Perceived Reasons for Change in Total Electricity Bill Amounts

Among customers who believed the total amount of their electricity bills had increased over the past three years, 78 percent believed the increase was due to changes in the overall price they pay for electricity while 28 percent (also) believed the increase was due to changes in their household's consumption level.

Table D.2.14: Perceived Reason for Change in Total Electricity Bill Amounts over the Past Three Years

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total
For those who reported increases in bills				
Due to changes in the overall price we pay for electricity	76%	79%	78%	78%
Due to changes in our consumption level	25%	31%	26%	28%
Don't know	10%	6%	10%	9%
For those who reported decreases in bills				
Due to changes in our consumption level	86%	85%	83%	85%
Due to changes in the overall price we pay for electricity	9%	16%	15%	14%
Don't know	7%	10%	8%	9%

*Totals may be greater than 100% due to multiple mentions.

Among customers who believed the total amount of their electricity bills had decreased over the past three years, 85 percent believed the decrease was due to changes in their household's consumption level while 14 percent (also) believed the decrease was due to changes in the overall price they pay for electricity.

D.2.5. Awareness and Opinions of BC Hydro's Residential Rate Structure

This section provides more detail on customers' prior awareness, understanding and opinions of BC Hydro's residential rate structure.

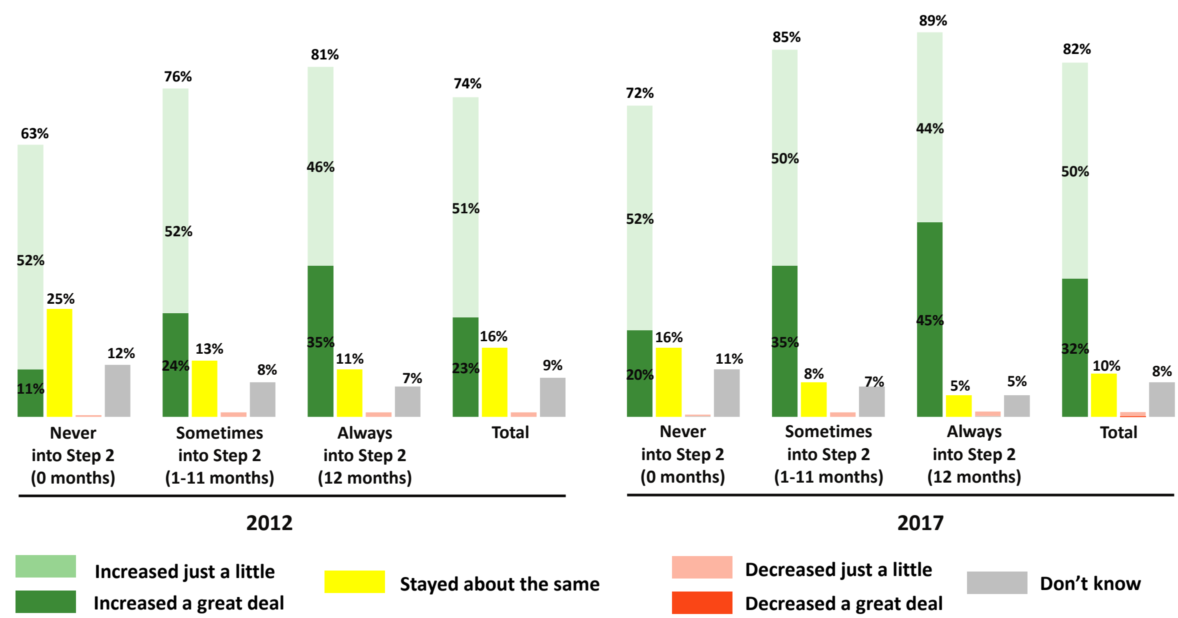
Perceived Change in BC Hydro's Current Residential Electricity Prices over the Past Three Years

In each of the 2012 and 2017 surveys, customers were also asked about the extent to which they believed residential electricity prices had changed – if at all – over the previous three years.

As illustrated in Figure D.1, 63 percent of customers that never incurred Step 2 electricity consumption in F2012 believed that electricity prices had increased over the previous three years. To compare, this proportion climbed to 76 percent among those that sometimes incurred Step 2 electricity consumption in the fiscal year and further to 81 percent that always did so.

Different insights and perspectives can be gained by bundling the 'increased just a little' and 'stayed about the same' responses during analysis. By doing so, it can be said that 77 percent of those that never incurred Step 2 electricity consumption in F2012 felt that prices had increased little – if at all – over the previous three years. To compare, this proportion measured lower at 65 percent among customers that sometimes incurred Step 2 electricity consumption and at 57 percent among those that always did so.

Figure D.1
Perceived Change in BC Hydro's Residential Electricity Prices over the Past Three Years
- By Step 2 Status of Electricity Consumption -



The findings in the 2012 survey are intuitively consistent with the actual change in electricity prices dating back to October 2008 when the RIB rate was implemented. As shown in Figure 2.1, at the time of the 2012 survey, the Step 1 price had existed for roughly 3.5 years and had been lower than the pre-RIB flat rate price for 2.5 of those years. This group would be expected to be less cognizant of price increases in these years and to be less responsive to them as compared to the two other cohorts. Analysis presented in an earlier section showed this in that a Step 1 price elasticity pertaining to that period was not detected with a high degree of confidence whereas a Step 2 price elasticity was.

The pattern of opinions toward the perceived change in electricity prices by Step 2 status identified in the 2012 survey emerged again in the 2017 survey, but with some shifts over the five year period. In each of the three Step 2 cohorts, the proportion of customers who felt that electricity prices had 'increased a great deal' over the previous three years measured higher in 2017 than in 2012. In particular, the proportion nearly doubled from 11 percent to 20 percent among the cohort that was never into Step 2. It is reasonable to believe, therefore, that this group of customers would have become comparably more responsive to an increase in electricity prices than they were five years earlier. This belief is backed by the fact that a statistically significant Step 1 price elasticity was ascertained once the F2016 and F2017 consumption data was added to the econometric analysis.

Unaided Awareness of BC Hydro's Residential Rate Structure by Region, Dwelling and Step 2 Consumption

As explained in Section 3.4.3., unaided awareness that BC Hydro uses an inclining block rate for charging residential households for their consumption of electricity measured highest at 53 percent among customer households that always incurred Step 2 electricity consumption in F2017. It follows that prior awareness of the inclining block rate continues to measure highest – 58 percent currently – among customers on Vancouver Island. These households were previously shown to have been the most likely to incur Step 2 consumption in F2017 and by extension, the most likely to have had the highest electricity bills.

Interestingly, the results of the analysis of regional elasticities in Section 3.3.1 also that showed Vancouver Island customers were more responsive to the Step 2 price than customers in other regions.

Table D.2.15: Unaided Awareness of BC Hydro's Residential Rate Structure by Region, Dwelling and Step 2 Status

	Inclining block rate	Flat rate	Declining block rate	Time of Use	Don't know	Total
Total	47%	21%	1%	8%	24%	100%
Region						
Lower Mainland	42%	23%	1%	8%	26%	100%
Vancouver Island	58%	15%	1%	7%	19%	100%
Southern Interior	49%	19%	1%	7%	25%	100%
North	45%	21%	1%	7%	26%	100%
Dwelling Type						
Single detached house	53%	19%	1%	7%	20%	100%
Duplex/Row house/townhouse	43%	20%	<1%	10%	27%	100%
Apartment/Condominium	37%	25%	1%	8%	29%	100%
Mobile home/other	49%	12%	1%	6%	31%	100%
Step 2 Consumption Status in F2017						
Never into Step 2 (0 months)	39%	23%	1%	9%	28%	100%
Sometimes into Step 2 (1-11 months)	49%	20%	1%	7%	23%	100%
Always into Step 2 (12 months)	53%	19%	<1%	8%	20%	100%

Row totals may not total 100% due to the rounding of values.

Consistent with findings tied to education and income, unaided awareness of the inclining block rate measured highest among customers who own single detached houses – the most expensive of the dwelling types, and typically the highest in consumption.

Unaided Awareness of BC Hydro's Residential Rate Structure by Household Demographics

Unaided awareness of the inclining block rate was strongly correlated to level of education, spanning 21 points from a low of 34 percent among customers who have earned no more than a high school diploma to a high of 55 percent among those who have attained university degrees. Related, awareness was also tied to annual income, spanning 19 points from a low of 37 percent among those with household earnings less than $40,000 to a high of 56 percent among those with household earnings of at least $120,000. Note that educated and affluent consumers are among the most likely to live in single detaches houses which have been shown to be the most likely of all dwellings to incur Step 2 electricity consumption. These customers are also known to be comparably more likely than others to be regular readers of public affairs information – conventionally in newspapers, but also online – in which electricity issues and rates are often covered.

Table D.2.16: Unaided Awareness of BC Hydro's Residential Rate Structure by Household Demographics

	Inclining block rate	Flat rate	Declining block rate	Time of Use	Don't know	Total
Total	47%	21%	1%	8%	24%	100%
Home Ownership						
Own/Co-op	49%	20%	1%	8%	22%	100%
Rent	36%	24%	1%	7%	33%	100%
Age of Primary Account Holder						
18-34	47%	23%	1%	6%	22%	100%
35-54	46%	23%	1%	8%	22%	100%
55+	47%	18%	1%	8%	26%	100%
Education of Primary Account Holder						
High school or less	34%	19%	1%	10%	37%	100%
College/vocational/technical/some university	47%	20%	1%	8%	23%	100%
University/Graduate Degree	55%	22%	1%	6%	17%	100%
Household Income						
Under $40,000	37%	18%	2%	8%	34%	100%
$40,000 < $80,000	47%	20%	1%	8%	24%	100%
$80,000 < $120,000	52%	20%	<1%	8%	20%	100%
$120,000 +	56%	25%	<1%	6%	13%	100%
Low Income Status						
Yes, 'low income' household	33%	20%	2%	10%	34%	100%
No	48%	21%	1%	7%	23%	100%

Row totals may not total 100% due to the rounding of values.

Consistent with other BC Hydro research, approximately 10 percent of the customer households in the 2017 surveys were classified as 'low income'. Among these customers, unaided awareness of the RIB rate measured 33 percent.

Unaided Awareness of BC Hydro's Residential Rate Structure by Heating Fuels

There was no meaningful difference in unaided awareness of the inclining block rate among customers who rely on electricity to heat their homes versus those who rely on natural gas, oil or propane (46% versus 47%). However, at 54 percent, customers who rely on electricity for their water heating were more likely than others to have been aware of the rate. To compare, this proportion decreased to 47 percent among customers with non-electric hot water tanks and further to 36 percent among those with central water heating. As previously explained, all of these findings reflect a complex interplay of factors that influence customer awareness of electricity rate structures, including space heating, water heating, dwelling and other demographic parameters.

Table D.2.17: Unaided Awareness of BC Hydro's Residential Rate Structure by Heating Fuels

	Inclining block rate	Flat rate	Declining block rate	Time of Use	Don't know	Total
Total	47%	21%	1%	8%	24%	100%
Main Space Heating Fuel						
Electricity	46%	19%	1%	7%	27%	100%
Non-Electric	47%	22%	1%	8%	22%	100%
Main Water Heating Fuel						
Electricity	54%	17%	1%	7%	22%	100%
Non-Electric	47%	21%	1%	8%	23%	100%
No hot water tank (central)	36%	25%	1%	8%	29%	100%
Main Space Heating and Water Heating Fuels						
Electric Heating & Electric Water	52%	17%	<1%	7%	23%	100%
Electric Heating & Non-Electric Water	51%	15%	0%	9%	25%	100%
Electric Heating & Central Water	37%	23%	1%	7%	32%	100%
Non-Electric Heating & Electric Water	56%	16%	1%	8%	19%	100%
Non-Electric Heating & Non-Electric Water	46%	22%	1%	8%	23%	100%
Non-Electric Heating & Central Water	36%	31%	<1%	10%	22%	100%

Row totals may not total 100% due to the rounding of values.

Understanding of the RIB Rate

After first soliciting their awareness of the method BC Hydro uses for charging their household's consumption of electricity, the survey informed respondents that an inclining block rate is indeed the method that BC Hydro uses. In doing so, the method was also introduced as BC Hydro's Two-Step Residential Conservation Rate and the Step 1 to Step 2 threshold and prices were detailed.

Table D.2.18: Understanding of the RIB Rate by the Incidence of Step 2 Electricity Consumption in F2017

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total
Total excellent + good + fair	37%	47%	51%	44%
Excellent	7%	14%	16%	12%
Good	19%	21%	24%	21%
Fair	11%	12%	11%	11%
Poor	1%	2%	2%	2%
Very poor	<1%	<1%	<1%	<1%
Don't know	<1%	<1%	<1%	<1%
Not aware of the RIB rate	61%	51%	47%	53%
Total	100%	100%	100%	100%

Column totals may not total 100% due to the rounding of values.

Having read the details about BC Hydro's Two-Step Residential Conservation Rate, a total of 44 percent of customers felt they actually had either an 'excellent', 'good' or 'fair' understanding of the rate prior to receiving the survey – this included some 33 percent professing either an 'excellent' or a 'good' understanding of it. These findings are generalizable to the entire population of BC Hydro's residential customers charged on this rate because the figures are fully based – the 53 percent of customers identified as not being previously aware that their consumption of electricity is charged on the RIB rate have not been excluded.

Closely following unaided awareness that residential electricity consumption is charged on an inclining block rate, the extent that customers understood the details of the RIB rate increased with the frequency of exposure to Step 2 consumption. While a total of 37 percent of customer households that never incurred Step 2 consumption in the twelve months of F2017 emerged to have either an 'excellent', 'good' or 'fair' understanding of the rate, this proportion increased to 47 percent among customers that sometimes incurred Step 2 consumption and further to 51 percent among customers that always incurred Step 2 consumption during this period.

Reported Change in 'Mindfulness' of Electricity Consumption over the Past Three Years

Among customers previously aware of the RIB rate, a total of 48 percent of them report that they have become either 'much more mindful' or 'somewhat more mindful' over the past three years of their consumption of electricity in relation to the Step 1 and Step 2 prices and thresholds.

Table D.2.19: Reported Change in 'Mindfulness' of Electricity Consumption over the Past Three Years

- among customers previously aware of the RIB rate –

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total
Total much more mindful + somewhat more mindful	43%	52%	46%	48%
Much more mindful	11%	13%	13%	13%
Somewhat more mindful	32%	38%	33%	35%
No change	55%	47%	52%	51%
Somewhat less mindful	1%	1%	1%	1%
Much less mindful	1%	0%	1%	<1%
Total	100%	100%	100%	100%

Column totals may not total 100% due to the rounding of values.
Don't know responses have been excluded from all calculations.

Awareness that the RIB Rate was Designed to Encourage Conservation

Among customers who correctly identified the inclining block rate as the method that BC Hydro uses for charging their household's consumption of electricity, 77 percent reported having been previously aware that the rate was designed to encourage conservation.

Table D.2.20: Awareness that the RIB Rate was Designed to Encourage the Conservation of Electricity

- among customers previously aware of the RIB rate -

	Yes, previously aware	No, not previously aware	Total
Region			
Lower Mainland	77%	23%	100%
Vancouver Island	80%	20%	100%
Southern Interior	75%	25%	100%
North	73%	27%	100%
Step 2 Consumption Status in F2017			
Never into Step 2 (0 months)	79%	21%	100%
Sometimes into Step 2 (1-11 months)	79%	21%	100%
Always into Step 2 (12 months)	73%	27%	100%
Education of Primary Account Holder			
High school or less	73%	27%	100%
College/vocational/technical/some university	74%	26%	100%
University/Graduate Degree	82%	18%	100%
Low Income Status			
Yes, 'low income' household	74%	26%	100%
No	77%	23%	100%

Row totals may not total 100% due to the rounding of values.

Awareness that the RIB rate was designed to encourage the conservation of electricity was correlated to education level, stepping up from a low of 73 percent among those who have attained no more than a high school diploma to a high of 82 percent among those who have earned university degrees. Again, this may reflect the fact that the most educated consumers are known to be more regular readers of newspapers in which electricity issues and rates are often covered.

How the RIB Rate Provides an Incentive to Manage Electricity

In each of the 2012 and 2017 surveys, customers who correctly identified the inclining block rate as the method that BC Hydro uses for charging their household's consumption of electricity and said it serves as an incentive to manage their use of it were further queried as to just how the rate acts as a motivator.

The single largest segment of these customers in 2017 – 32 percent – reported that the difference between the Step 1 and Step 2 prices acts as an incentive to their household to manage its consumption of electricity. These customers indicated that if they can manage their use of electricity effectively in a billing period, then they can have most of it charged at the lower, Step 1 price, perhaps even avoiding Step 2 consumption and the higher, Step 2 price altogether. This sentiment measured even higher at 37 percent specifically among customers that sometimes incurred Step 2 consumption in F2017 – possibly reflecting success in this regard.

One in five customers – specifically, 21 percent in 2017 – continued to say that the lower, Step 1 price on its own acts as an incentive to their household. They consider the lower, Step 1 price as being the price applicable to all of their electricity consumption in a billing period, and they try to manage their consumption of electricity on that basis. At 41 percent, it comes intuitively that this was the most prevalent view specifically among households that never incurred Step 2 consumption in F2017.

Table D.2.21: How the RIB Rate Provides an Incentive to Manage Electricity - among customers previously aware of the RIB Rate and who said it serves as an incentive in 2017 -

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total
The lower, Step 1 price on its own incents our household…	41%	14%	8%	21%
The higher, Step 2 price on its own incents our household…	4%	12%	17%	11%
The difference between the Step 1 and Step 2 prices incents our household…	28%	37%	26%	32%
The consumption threshold on its own incents our household…	15%	17%	18%	17%
The stepped rate does not incent my household in any of these particular ways…	9%	17%	25%	16%
Don't know	2%	3%	6%	4%
Total	100%	100%	100%	100%

Column totals may not total 100% due to the rounding of values.
Binning of Step 2 status is based on electricity consumption in F2017.

Just 11 percent of customers with proven awareness of the inclining block rate in 2017 felt that the higher, Step 2 price on its own serves as an incentive to their household to manage its use of electricity. As was the case in 2012, these customers consider the higher, Step 2 price as being the price applicable to the part of electricity consumption in a billing period that they have control over, and they try to manage their use of electricity on that basis.

A total of 17 percent of customers reported that price does not manifest itself in any of these ways as an incentive to them to manage their use of electricity; instead, they point to the consumption threshold. For these customers, regardless of the difference in the Step 1 and 2 prices and the amount they pay on their bill, they compare their household's consumption to the Step 1 to Step 2 threshold simply because they like to keep their consumption as low as possible compared to it.

Although they understood that their household's consumption of electricity is charged on an inclining block rate and they said that the rate serves as an incentive to their household to manage its use of it, 16 percent of customers in 2017 subsequently reported that the rate does not incent their household to manage its consumption of electricity in any of the four ways as presented. It is not clear if these particular customers are indeed incented by the rate in some different way, or if they were inconsistent in their responses.

Once again, results from the 2012 survey were by and large the same as those in the 2017 survey.

Customer Support of the RIB Rate

High level findings in regard to customer opinion of the RIB rate were reported in Section 3.4.3. Table D.2.22 below details the findings by region, dwelling type, Step 2 consumption status in F2017 and low income status.

Table D.2.22: Customer Support of the RIB Rate

	Don't know	Strongly oppose	Somewhat oppose	Indifferent	Somewhat support	Strongly support	Total	Total support
Total	8%	8%	11%	18%	35%	20%	100%	55%
Region								
Lower Mainland	9%	5%	9%	18%	37%	22%	100%	59%
Vancouver Island	6%	12%	15%	19%	30%	18%	100%	48%
Southern Interior	6%	10%	14%	19%	35%	16%	100%	51%
North	9%	12%	11%	21%	33%	14%	100%	47%
Dwelling Type								
Single detached house	7%	11%	12%	18%	34%	18%	100%	52%
Duplex/Row house/townhouse	11%	5%	11%	19%	35%	18%	100%	54%
Apartment/Condominium	9%	3%	8%	18%	37%	26%	100%	63%
Mobile home/other	8%	11%	17%	27%	25%	13%	100%	38%
Step 2 Consumption Status in F2017								
Never into Step 2 (0 months)	8%	3%	6%	15%	37%	31%	100%	68%
Sometimes into Step 2 (1-11 months)	8%	9%	11%	20%	35%	17%	100%	52%
Always into Step 2 (12 months)	7%	14%	17%	20%	30%	12%	100%	42%
Awareness of the RIB rate								
Previously aware of RIB rate	2%	12%	14%	15%	34%	23%	100%	57%
Not previously aware	13%	5%	8%	21%	35%	18%	100%	53%
Low Income Status								
Yes, 'low income' household	14%	6%	9%	17%	31%	22%	100%	53%
No	7%	8%	11%	18%	35%	20%	100%	55%

Row totals may not total 100% due to the rounding of values.

Reported Change in Support of the RIB Rate over the Past Three Years

Among customers who were previously aware of the RIB rate in the 2017 survey, the majority – 58 percent – said that there had been 'no change' over the past three years in their opinion of it. On the other hand, a total of 19 percent said that they had become more supportive of it while 20 percent said that they had become more opposed to it. As detailed in the table below, customers who had never incurred Step 2 electricity consumption in F2017 were the most likely to have become more supportive of the RIB rate.

Table D.2.23: Reported Change in Support of the RIB Rate over the Past Three Years

– among customers who correctly identify being charged on the RIB rate –

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total
Total much more supportive + somewhat more supportive	28%	18%	12%	19%
Much more supportive of it	9%	5%	3%	5%
Somewhat more supportive of it	19%	13%	10%	14%
No change	61%	58%	55%	58%
Somewhat more opposed to it	4%	12%	14%	10%
Much more opposed to it	3%	10%	15%	10%
Don't know	1%	1%	1%	1%
Not Applicable – not aware of the RIB rate 3 years ago	1%	2%	2%	2%
Total	100%	100%	100%	100%

Column totals may not total 100% due to the rounding of values.

D.2.6. Customer Behaviour in Relation to Awareness of the RIB Rate

This section presents detailed findings of how electricity consumption, investments in home energy efficiency upgrades and conservation program participation levels differ among RIB-aware and RIB-unware customers.

Electricity Consumption by RIB Rate Awareness

As a first investigation into the relationship between consumption and awareness, an ANOVA (analysis of variance) statistical test showed that the pool of customer households previously aware of the RIB rate incurred significantly higher average consumption in F2017 than the pool of customers not previously aware of the rate (10,447 kWh versus 8,707 kWh). In fact, while the differences were not always statistically significant at the 95 percent confidence level, RIB-aware customers incurred higher consumption in every scenario shown Table D.2.24. As customers aware of the rate would likely never choose to deliberately consume more electricity, the findings uncover a causal path: greater consumption leads to a greater likelihood of being aware of the rate.

Table D.2.24: ANOVA Tests: Mean Electricity Consumption in F2017 by RIB Rate Awareness

	Customers aware of the RIB Rate (kWh)	Customers not aware of the RIB Rate (kWh)	Difference between groups (kWh)	F Statistic of Difference	Significance
All Customers					
Total F2017 consumption ⇒	10,447	8,707	1,740	44.38	0.000*
Total Step 1 consumption ⇒	6,305	5,777	528	49.26	0.000*
Total Step 2 consumption ⇒	4,142	2,930	1,212	30.94	0.000*
Customers Never into Step 2 (0 months)					
Total F2017 consumption ⇒	3,517	3,339	178	3.37	0.067**
Total Step 1 consumption ⇒	3,517	3,339	178	3.37	0.067**
Total Step 2 consumption ⇒	-	-	-	-	-
Customers Sometimes into Step 2 (1-11 months)					
Total F2017consumption ⇒	9,858	9,159	699	12.67	0.000*
Total Step 1 consumption ⇒	6,886	6,726	160	7.59	0.006*
Total Step 2 consumption ⇒	2,972	2,433	539	10.52	0.001*
Customers Always into Step 2 (12months)					
Total F2017 consumption ⇒	19,083	17,806	1,277	3.08	0.080**
Total Step 1 consumption ⇒	8,122	8,122	0	0.00	1.000
Total Step 2 consumption ⇒	10,960	9,684	1,277	3.08	0.080**

* The difference between mean consumption levels is statically significant at the 95% level of confidence.
** The difference between mean consumption levels is statically significant at the 90% level of confidence.

In a second investigation, a linear regression was conducted with consumption as the dependent variable. The independent variables consisted of rate awareness as well as various combinations of region, dwelling type, heating fuel, floor area, income, household occupants, and saturation levels of some major end-uses.

The coefficient for the awareness variable always emerged positive in the models, but typically not statistically significant at the 95 percent level of confidence. This meant that in the estimation of a household's electricity consumption using these models, the estimate would sometimes increase – but never decrease – if the household was aware of the inclining block rate. As gleaned from both investigations, awareness of the rate does not directly lead households to having lower consumption as strictly compared to households unaware of the rate.

However, compared over time, households aware of the RIB rate may have had higher energy savings in F2017 than had they not been aware of the rate and/or higher energy savings than in periods prior to becoming aware of the rate. To investigate this, a much larger dataset of customer accounts would be required, including a long time series of consumption history both before and after households became aware of the RIB as disaggregated by a finely specified date variable.

Investments in Home Energy Efficiency Upgrades by Awareness of the RIB Rate

Those who knew that their consumption of electricity was charged on the RIB rate were slightly more likely than others to have completed at least one of the eight upgrades investigated (52% vs. 48%), including more likely to have completed draft proofing upgrades (21% vs. 15%) and insulation upgrades (16% vs. 12%).

Table D.2.25: Investments in Home Energy Efficiency Upgrades by Awareness of the RIB Rate

	Customers aware of the RIB Rate	Customers not aware of the RIB Rate	Difference between groups
Net Total: Any of the upgrades			
All customers	52%	48%	4 points*
Low income customers	44%	34%	10 points
Hot water tank installation/upgrade			
All customers	30%	28%	2 points
Low income customers	15%	15%	0 points
Window upgrades			
All customers	24%	22%	2 points
Low income customers	23%	17%	6 points
Draftproofing upgrades			
All customers	21%	15%	6 points*
Low income customers	19%	14%	5 points
Door upgrades			
All customers	17%	16%	1 point
Low income customers	12%	12%	0 points
Insulation upgrades			
All customers	16%	12%	4 points*
Low income customers	15%	4%	11 points *
Furnace installation/upgrade			
All customers	12%	12%	0
Low income customers	5%	8%	(-3) points
Air source heat pump installation/upgrade			
All customers	4%	3%	1 point
Low income customers	1%	0%	1 point
Ground source heat pump installation/upgrade			
All customers	1%	1%	0
Low income customers	0%	1%	(-1) point

* Statistically significant difference between the two groups at the 95% level of confidence.

Low income customers previously aware of the RIB rate were more likely than other low income customers to have completed some home energy-efficiency upgrades. Once again, the differences were not always statistically significant because the absolute number of low income households in the survey was not large enough to afford a high level of confidence in the findings.

Program Participation by RIB Rate Awareness

BC Hydro offers several energy conservation initiatives and rebate offerings to its residential customers to encourage them to improve energy efficiency and to adopt more energy conscious behaviours in their homes. An investigation into these programs was conducted to assist in understanding whether there were differences in program participation among those who correctly understood their use of electricity was charged on the RIB rate as compared to other customers.

This procedure relied on customer program participation markers from BC Hydro's billing system, strictly since the implementation of the RIB rate in October 2008, and customer awareness of the RIB rate.

Table D.2.26: Program Participation since RIB Rate Inception by Awareness of the RIB Rate

	Customers aware of the RIB Rate	Customers not aware of the RIB Rate	Difference between groups
Net: Any of the Programs (excludes Energy Visualization Portlet)			
All customers	32%	22%	10 points*
Low income customers	30%	25%	5 points
Appliance Rebate Program			
All customers	14%	9%	5 points *
Low income customers	8%	4%	4 points
Refrigerator Buy-Back Program			
All customers	7%	7%	0 points
Low income customers	7%	5%	2 points
Low Income Program			
All customers	4%	4%	0 points
Low income customers	16%	13%	3 points
HERO Program			
All customers	<1%	<1%	0 points
Low income customers	0%	0%	0 points
Team Power Smart Residential Behavior Program			
All customers	14%	6%	8 points *
Low income customers	14%	7%	7 points *
Energy Visualization Portlet			
All customers	29%	15%	14 points *
Low income customers	27%	14%	13 points *

* Statistically significant difference between the two groups at the 95% level of confidence.

Customers who understood that their household's consumption of electricity is charged on the RIB rate emerged to be more likely than other customers to have participated in the Residential Behaviour Program (14% vs. 6%) and the Appliance Rebate Program (14% vs. 9%) since the rate came into effect in October 2008. In addition, these RIB aware customers were more likely to have signed-up on BC Hydro's website to be able to view their detailed electricity use by the month, week, day or even hour.

Low income customers previously aware of the RIB rate were more likely than other low income customers to have participated in some conservation programs. The differences were not always statistically significant because the absolute number of low income households in the survey was not large enough to afford a high level of confidence in the findings.

In-Home Behaviours by RIB Rate Awareness

The customer survey was comprised of several banks of questions about in-home conservation behaviours. The tables in this section of the report document the self-reported frequency that individuals and/or their households typically exhibit. Findings are detailed for those aware of the RIB rate and those unaware of the rate – within the entire customer class as well as among low income customers. Statistical testing was based on aggregated or pooled data.

Frequency scores in the tables are based on the 4-point scales ('always', 'usually', 'occasionally', 'never') extensively utilized in the surveys. For any behaviour, statistical testing focused on the difference between the RIB-aware and RIB-unaware customer groups in the top-box score ('always') as well as the top-two box score ('always' + 'usually') as it is the difference in these categories that might help illuminate what might be behind any differences in the groups' actual energy consumption.

Given the large sample size for the entire customer class, statistically significant differences can emerge between RIB-aware and RIB-unaware customers for the smallest of gaps – even 2 percentage points. With this in mind, it is important to note that statistically significant differences in scores do not necessarily equate to meaningful differences in behaviours.

On the other hand, the pool of low income customer households is comparably smaller, and as such differences between RIB-aware and RIB-unaware customers were not always statistically significant because the absolute number of low income households in the survey was not large enough to afford a high level of confidence in the findings.

Plug-Load Behaviours

Table D.2.27: Plug-Load Behaviours

	Never	Occasionally	Usually	Always	Total	Total Always + Usually
Turn off the TV when no one is in the room or actively watching a program						
All Customers						
Previously aware of RIB rate	1%	5%	33%	62%*	100%	95%**
Not previously aware	3%	8%	33%	56%	100%	89%
Low Income Customers						
Previously aware of RIB rate	0%	5%	25%	70%*	100%	95%
Not previously aware	2%	9%	31%	57%	100%	88%
Turn off computer and printer when not in use OR use the power-save mode						
All Customers						
Previously aware of RIB rate	4%	8%	29%	58%	100%	87%**
Not previously aware	5%	12%	26%	57%	100%	83%
Low Income Customers						
Previously aware of RIB rate	2%	7%	29%	62%	100%	91%
Not previously aware	1%	11%	29%	60%	100%	88%

Row totals may not total 100% due to the rounding of values.
Not applicable and Don't Know responses have been excluded from all calculations.
* Statistically significant difference between the two groups' top-box score ('always') at the 95% level of confidence.
** Statistically significant difference between the two groups' top-two box score ('always' + 'usually') at the 95% level of confidence.

Lighting Behaviours

Table D.2.28: Lighting Behaviours

	Never	Occasionally	Usually	Always	Total	Total Always + Usually
Turn off lights when no one is in the room						
All Customers						
Previously aware of RIB rate	<1%	4%	39%	57%	100%	96%**
Not previously aware	1%	5%	33%	61%*	100%	94%
Low Income Customers						
Previously aware of RIB rate	0%	2%	31%	67%	100%	98%
Not previously aware	1%	3%	25%	71%	100%	96%
Only have the minimum number of lights on in a room for what I am doing						
All Customers						
Previously aware of RIB rate	1%	5%	47%	48%	100%	95%**
Not previously aware	1%	7%	39%	52%*	100%	92%
Low Income Customers						
Previously aware of RIB rate	0%	1%	37%	62%	100%	99%**
Not previously aware	<1%	6%	29%	64%	100%	94%
Purchase the most energy-efficient light bulbs, even if they are more expensive						
All Customers						
Previously aware of RIB rate	4%	20%	35%	41%*	100%	76%
Not previously aware	4%	22%	37%	37%	100%	74%
Low Income Customers						
Previously aware of RIB rate	5%	16%	30%	49%*	100%	79%
Not previously aware	5%	25%	32%	38%	100%	70%

Row totals may not total 100% due to the rounding of values.
Not applicable and Don't Know responses have been excluded from all calculations.
* Statistically significant difference between the two groups' top-box score ('always') at the 95% level of confidence.
** Statistically significant difference between the two groups' top-two box score ('always' + 'usually') at the 95% level of confidence.

Space Heating Behaviours

Table D.2.29: Space Heating Behaviours

	Never	Occasionally	Usually	Always	Total	Total Always + Usually
Dress more warmly in cold weather and reduced/keep the thermostat to 20 ^{o} Celsius (68 ^{o} Fahrenheit) or below						
All Customers						
Previously aware of RIB rate	9%	16%	36%	39%	100%	75%
Not previously aware	11%	17%	33%	39%	100%	72%
Low Income Customers						
Previously aware of RIB rate	8%	10%	35%	47%	100%	82%
Not previously aware	10%	18%	30%	42%	100%	72%
Use a communicating/programmable thermostat or manually turn down the heat at night						
All Customers						
Previously aware of RIB rate	12%	5%	18%	66%*	100%	84%**
Not previously aware	13%	8%	24%	55%	100%	79%
Low Income Customers						
Previously aware of RIB rate	21%	5%	17%	57%	100%	74%
Not previously aware	18%	8%	27%	48%	100%	75%
Use a communicating/programmable thermostat or manually turn down the heat when no one is home						
All Customers						
Previously aware of RIB rate	11%	9%	20%	60%*	100%	80%**
Not previously aware	13%	11%	23%	53%	100%	76%
Low Income Customers						
Previously aware of RIB rate	20%	2%	21%	57%	100%	78%
Not previously aware	13%	13%	27%	47%	100%	74%
Reduce temperature in unused rooms by closing vents or turning down thermostats						
All Customers						
Previously aware of RIB rate	13%	12%	25%	50%*	100%	75%
Not previously aware	15%	13%	26%	46%	100%	72%
Low Income Customers						
Previously aware of RIB rate	15%	6%	25%	54%	100%	80%
Not previously aware	9%	14%	24%	53%	100%	77%
Maintain the temperature of your home specifically for your dog(s) or cat(s) when no one is home						
All Customers						
Previously aware of RIB rate	53%	15%	18%	14%	100%	32%
Not previously aware	41%	19%	20%	20%*	100%	40%**
Low Income Customers						
Previously aware of RIB rate	41%	14%	16%	29%	100%	45%
Not previously aware	32%	20%	25%	22%	100%	48%

Row totals may not total 100% due to the rounding of values.
Not applicable and Don't Know responses have been excluded from all calculations.
* Statistically significant difference between the two groups' top-box score ('always') at the 95% level of confidence.
** Statistically significant difference between the two groups' top-two box score ('always' + 'usually') at the 95% level of confidence.

Space Cooling Behaviours

Table D.2.30: Space Cooling Behaviours

	Never	Occasionally	Usually	Always	Total	Total Always + Usually
Have the air conditioning come on only when it is 26° Celsius (79° Fahrenheit) or higher during the summer to save energy						
All Customers						
Previously aware of RIB rate	21%	19%	28%	32%	100%	60%
Not previously aware	20%	19%	34%	27%	100%	61%
Low Income Customers						
Previously aware of RIB rate	14%	7%	51%	27%	100%	78%
Not previously aware	20%	18%	36%	26%	100%	62%
Draw the window coverings during hot weather to reduce heat in the dwelling						
All Customers						
Previously aware of RIB rate	4%	7%	29%	60%	100%	89%**
Not previously aware	5%	10%	29%	56%	100%	85%
Low Income Customers						
Previously aware of RIB rate	2%	5%	37%	56%	100%	93%
Not previously aware	5%	15%	34%	46%	100%	80%
Clean the air conditioning filter and coils at least once per season						
All Customers						
Previously aware of RIB rate	7%	16%	23%	54%*	100%	77%**
Not previously aware	11%	18%	26%	46%	100%	71%
Low Income Customers						
Previously aware of RIB rate	4%	16%	32%	48%	100%	80%
Not previously aware	14%	17%	23%	46%	100%	69%
Cool only the rooms to be occupied rather than the whole home						
All Customers						
Previously aware of RIB rate	16%	13%	24%	48%	100%	72%
Not previously aware	16%	9%	27%	48%	100%	75%
Low Income Customers						
Previously aware of RIB rate	7%	9%	19%	66%	100%	84%
Not previously aware	4%	19%	34%	43%	100%	77%
Use air conditioning only when very hot and natural ventilation is insufficient						
All Customers						
Previously aware of RIB rate	5%	10%	29%	56%	100%	85%
Not previously aware	5%	8%	29%	58%	100%	87%
Low Income Customers						
Previously aware of RIB rate	2%	11%	18%	69%	100%	87%
Not previously aware	12%	9%	29%	50%	100%	79%

Row totals may not total 100% due to the rounding of values.
Not applicable and Don't Know responses have been excluded from all calculations.
* Statistically significant difference between the two groups' top-box score ('always') at the 95% level of confidence.
** Statistically significant difference between the two groups' top-two box score ('always' + 'usually') at the 95% level of confidence.

Laundry Behaviours

Table D.2.31: Laundry Behaviours (in own home only)

	Never	Occasionally	Usually	Always	Total	Total Always + Usually
Only do laundry with full loads						
All Customers						
Previously aware of RIB rate	1%	5%	48%	47%	100%	95%**
Not previously aware	1%	8%	44%	47%	100%	91%
Low Income Customers						
Previously aware of RIB rate	4%	5%	37%	54%	100%	91%
Not previously aware	4%	6%	37%	54%	100%	90%
Use cold water wash and rinse when doing laundry						
All Customers						
Previously aware of RIB rate	6%	22%	33%	39%	100%	72%
Not previously aware	6%	19%	30%	45%*	100%	75%
Low Income Customers						
Previously aware of RIB rate	6%	31%	24%	39%	100%	63%
Not previously aware	10%	20%	22%	48%	100%	70%
Clean the lint filter before drying clothes						
All Customers						
Previously aware of RIB rate	<1%	3%	15%	82%*	100%	97%**
Not previously aware	1%	4%	16%	79%	100%	95%
Low Income Customers						
Previously aware of RIB rate	0%	3%	5%	92%*	100%	97%
Not previously aware	4%	3%	15%	78%	100%	93%
Use the temperature/moisture sensor to turn off the dryer rather than use the timer						
All Customers						
Previously aware of RIB rate	17%	11%	22%	50%*	100%	72%**
Not previously aware	27%	11%	21%	41%	100%	62%
Low Income Customers						
Previously aware of RIB rate	10%	10%	15%	64%*	100%	80**
Not previously aware	29%	8%	20%	43%	100%	63%
Hang clothes to dry rather than machine dry						
All Customers						
Previously aware of RIB rate	21%	46%	21%	11%	100%	32%
Not previously aware	20%	49%	18%	13%	100%	31%
Low Income Customers						
Previously aware of RIB rate	29%	30%	19%	22%	100%	41%
Not previously aware	19%	41%	21%	19%	100%	40%

Row totals may not total 100% due to the rounding of values.
Not applicable and Don't Know responses have been excluded from all calculations.
* Statistically significant difference between the two groups' top-box score ('always') at the 95% level of confidence.
** Statistically significant difference between the two groups' top-two box score ('always' + 'usually') at the 95% level of confidence.

Dishwashing Behaviours

Table D.2.32: Dishwashing Behaviours

	Never	Occasionally	Usually	Always	Total	Total Always + Usually
Only turn on the dishwasher when it is full						
All Customers						
Previously aware of RIB rate	1%	2%	21%	76%	100%	97%**
Not previously aware	1%	4%	21%	74%	100%	95%
Low Income Customers						
Previously aware of RIB rate	1%	5%	17%	77%	100%	94%**
Not previously aware	5%	12%	13%	70%	100%	83%
Air dry the dishes in the dishwasher rather than use the dry cycle						
All Customers						
Previously aware of RIB rate	30%	22%	17%	31%*	100%	48%**
Not previously aware	34%	23%	15%	28%	100%	43%
Low Income Customers						
Previously aware of RIB rate	18%	21%	22%	40%	100%	61%
Not previously aware	30%	21%	16%	34%	100%	49%

Row totals may not total 100% due to the rounding of values. Not applicable and Don't Know responses have been excluded from all calculations.
* Statistically significant difference between the two groups' top-box score ('always') at the 95% level of confidence.
** Statistically significant difference between the two groups' top-two box score ('always' + 'usually') at the 95% level of confidence.

Behaviours Relating to Water Use

Table D.2.33: Behaviours Relating to Water Use

	Never	Occasionally	Usually	Always	Total	Total Always + Usually
Keep shower times to no more than 5 minutes each						
All Customers						
Previously aware of RIB rate	20%	29%	35%	16%	100%	51%
Not previously aware	22%	30%	31%	17%	100%	48%
Low Income Customers						
Previously aware of RIB rate	19%	33%	26%	23%	100%	48%
Not previously aware	24%	32%	28%	16%	100%	44%
Turn off the water heater when no one is in the home for more than 2-3 days [a]						
All Customers						
Previously aware of RIB rate	59%	12%	11%	18%*	100%	29%
Not previously aware	63%	12%	12%	14%	100%	25%
Low Income Customers						
Previously aware of RIB rate	45%	19%	12%	24%	100%	36%
Not previously aware	55%	16%	14%	14%	100%	29%

Row totals may not total 100% due to the rounding of values. Not applicable and Don't Know responses have been excluded from all calculations.
a. Only among homes with hot water tanks.
* Statistically significant difference between the two groups' top-box score ('always') at the 95% level of confidence.
** Statistically significant difference between the two groups' top-two box score ('always' + 'usually') at the 95% level of confidence.

Other Behaviours

Table D.2.34: Other Behaviours

	Never	Occasionally	Usually	Always	Total	Total Always + Usually
Think about ways to save electricity						
All Customers						
Previously aware of RIB rate ⇒	1%	26%	45%	27%	100%	73%**
Not previously aware ⇒	3%	31%	39%	27%	100%	66%
Low Income Customers						
Previously aware of RIB rate ⇒	2%	18%	39%	41%	100%	80%**
Not previously aware ⇒	3%	29%	28%	41%	100%	68%
Pay more for products that are environmentally friendly						
All Customers						
Previously aware of RIB rate ⇒	5%	37%	45%	13%	100%	58%
Not previously aware ⇒	5%	38%	39%	18%*	100%	57%
Low Income Customers						
Previously aware of RIB rate ⇒	5%	35%	43%	17%	100%	60%
Not previously aware ⇒	8%	33%	34%	25%	100%	59%

Row totals may not total 100% due to the rounding of values.
Not applicable and Don't Know responses have been excluded from all calculations.
* Statistically significant difference between the two groups' top-box score ('always') at the 95% level of confidence.
** Statistically significant difference between the two groups' top-two box score ('always' + 'usually') at the 95% level of confidence.

Customer Behaviour and Electricity Consumption by RIB Step 2 Price Alerts

BC Hydro's billing system shows that a total of 5 percent of customer households have signed up online to receive email notifications that indicate when their consumption of electricity is halfway to reaching the higher Step 2 price in a billing period, as well as when it has reached it. This incidence increased through each of the three consumption bins, having measured 2 percent among households that never incurred Step 2 electricity consumption in F2017, 6 percent among customers that sometimes incurred Step 2 consumption in that year and 7 percent among customers that always did so.

Table D.2.35: Incidence of Customers Signed-Up to Receive Step 2 Price Alerts

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total
Signed-up to receive Step 2 price alerts	2%	6%	7%	5%
Not signed-up	98%	94%	93%	95%
Total	100%	100%	100%	100%

Incidences ascertained from the customer account billing system.

Among customers in the 2017 survey that have signed up to receive the price alerts, 64 percent reported that they typically make more of an effort to manage their consumption of electricity when their household receives the price alerts – 35 percent do not.

At 52 percent, the majority of customers that always incurred Step 2 electricity consumption in F2017 reported that they do make more of an effort to manage their consumption when they receive the price alerts, but this proportion measured 14 to 17 points lower than the other two customer groups.

Table D.2.36: Effort in Managing Household Electricity Consumption When a Step 2 Price Alert Received

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total
Total much more of an effort + a little more of an effort	66%	69%	52%	64%
Much more of an effort	52%	30%	18%	29%
A little more of an effort	14%	39%	34%	35%
No change	34%	30%	45%	35%
A little less of an effort	0%	0%	0%	0%
Much less of an effort	0%	0%	0%	0%
Not Applicable – never received a Step 2 price alert	0%	1%	2%	1%
Total	100%	100%	100%	100%

Column totals may not total 100% due to the rounding of values.
Don't know responses have been excluded from all calculations.

Understanding the extent that the Step 2 price alerts assisted customers to manage their electricity consumption was difficult because these customers were among those with the highest consumption to begin with whereas others had comparably lower consumption. Such understanding was best ascertained by comparing the pool of customers who received and acted on the price alerts to a pool of customers that did not receive the alerts, but were nonetheless as similar as possible in other ways, especially in their Step 2 status.

Table D.2.37: ANOVA Tests: Mean Electricity Consumption in F2017 by Step 2 Price Alerts

	Received and acted on a Step 2 price alert (kWh)	All others (kWh)	Difference between groups (kWh)	F Statistic of Difference	Significance
Customers that were sometimes (1-11 months) or always into Step 2 (12 months)					
Total F2017 consumption ⇒	11,528	12,334	806	0.824	0.364
Total Step 1 consumption ⇒	7,137	7,219	82	0.378	0.539
Total Step 2 consumption ⇒	4,391	5,115	724	0.768	0.381
Customers that were always into Step 2 (12 months)					
Total F2017 consumption ⇒	17,885	18,520	635	0.159	0.690
Total Step 1 consumption ⇒	8,122	8,122	0	0.000	1.000
Total Step 2 consumption ⇒	9,763	10,398	635	0.159	0.690
Customers in single detached houses that were always into Step 2 (12 months)					
Total F2017 consumption ⇒	18,406	18,859	453	0.072	0.789
Total Step 1 consumption ⇒	8,122	8,122	0	0.000	1.000
Total Step 2 consumption ⇒	10,284	10,737	453	0.072	0.789

For households that chose to act on the Step 2 price alerts, various analyses showed – depending on the comparison scenario – that their Step 1 and/or Step 2 electricity consumption in F2017 was lower than other households. The differences were not statistically significant, however, largely because the absolute number of households in the survey that received the price alerts and acted on them was not large enough to afford a high level of confidence in the findings.

Extent that the RIB Rate was a Factor in Purchasing a Non-Electric Item

Customers aware of the RIB rate were asked if they had purchased any natural gas, oil or propane equipment or appliances in the past three years and, if they had done so, how much of a factor the rate was in their decision to purchase it as opposed to one powered by electricity.

Table D.2.38 details the purchase rates for the six non-electric items and for each, the extent that customers said the RIB rate was a factor in choosing non-electric type rather than one powered by electricity.

Table D.2.38: Extent that the RIB Rate was a Factor in Purchasing a Non-Electric Item in the Past Three Years

- among customers previously aware of the RIB rate and who purchased the item –

		Extent that the RIB Rate was a factor in the purchase decision					
	Purchased	Don’t know	No factor at all	Minor factor	Major factor	Total	Total major + minor factor
Gas/Propane Fireplace	4%	2%	38%	15%	46%	100%	61%
Gas/Oil Furnace	6%	<1%	40%	21%	39%	100%	60%
Gas Range/Cooktop	4%	1%	42%	22%	35%	100%	57%
Gas/Oil/Propane Water Heater	6%	1%	46%	18%	35%	100%	53%
Gas/Propane Patio Heater	3%	2%	46%	20%	33%	100%	53%
Gas Lawnmower	7%	0%	63%	18%	18%	100%	36%

Row totals may not total 100% due to the rounding of values.

D.2.7. Customer Support of a Flat Rate

To close out the section on rate structures in the 2017 survey, customer respondents were asked their opinion of a flat rate. The question was prefaced with a statement that BC Hydro may one day consider altering its method of charging customers for their consumption of electricity to address changes in energy policy and objectives. Customers were also reminded that under a flat rate, the price per kilowatt hour (kWh) of electricity is constant regardless of the amount of electricity used in a billing period.

A total of 33 percent of customers reported that they would support a flat rate, 20 percent would be indifferent towards it, and 38 percent would be opposed to it. At 44 percent, support for a flat rate measured highest among customers households who always incurred Step 2 electricity consumption in F2017.

Table D.2.39: Customer Support of a Flat Rate

	Never into Step 2 (0 months)	Sometimes into Step 2 (1-11 months)	Always into Step 2 (12 months)	Total
Total strongly support + somewhat support	22%	34%	44%	33%
Strongly support	8%	12%	19%	12%
Somewhat support	15%	22%	25%	21%
Indifferent	20%	20%	19%	20%
Somewhat oppose	25%	21%	18%	22%
Strongly oppose	24%	15%	8%	16%
Don’t know	9%	10%	11%	10%
Total	100%	100%	100%	100%

Column totals may not total 100% due to the rounding of values.

Appendix E: Survey Instrument

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Survey ID: 000000
Pass Key: 000000

ATTN: <MAILING_NAME>
<MAILING_ADDRESS>
<MAILING_TOWN, PROVINCE, POSTAL>

IN REGARDS TO SERVICE ADDRESS:
<SERVICE_ADDRESS>
<SERVICE_TOWN>

July/August 2017

Dear Customer:

As per the invitation letter previously sent to your household, you have been selected at random from all BC Hydro customers to be part of this Residential Rate Survey. If you have already completed your survey on the Internet, then we thank you for doing so and you may discard this booklet.

New technologies, population increases, industrial growth and energy policies are all factors that determine how much electricity B.C. will need in the future. Understanding our residential customers' opinions about electricity and electricity rates also plays a role in this regard and as such, your participation in this survey is extremely important.

The Mustel Group, an independent research company based in B.C., is assisting us to conduct it. Your responses will be held in strict confidence by BC Hydro's Evaluation department and will be compiled with those of other customers for the research and planning purposes identified above.

<u>Please ensure that your survey responses refer to the residence located at the service address as shown above.</u> The survey should be completed by either the primary or joint account holder.

You may complete this printed survey and return it in the postage paid envelope provided or, alternatively, you may access the electronic version of the survey on the Internet by typing the website address below into a browser's address bar and using the survey ID and pass key shown at the top of this page.

The online survey has been optimized for completion on a smartphone, but completion on a computer or tablet – should you have one – will be made easier due to their larger screens and the survey's layout.

www.web-research-online.com/bchydro.html ⇐ type this address in; do not use a search engine.

Please complete the survey by August 18, 2017, and for doing so, you can enter your name in a draw for one of four $250 gift cards to a home improvement retailer of your choice. If you complete the survey on the Internet, your name will be entered in the draw one additional time. Also, if your completed survey is received (in the mail or submitted via the Internet) by August 8, your name will be entered in the draw one additional time.

Contact information is detailed on the inside cover of this booklet should you have any questions about how to complete the survey or why BC Hydro has commissioned it.

Thank you for your cooperation and prompt response. The information you provide is extremely important to us.

Yours truly,

Anthea Jubb

Anthea Jubb
Senior Regulatory Manager, Tariffs

Residential Rate Survey

You and your household have been randomly selected from all BC Hydro residential customers to participate in this Residential Rate Survey. Your participation in this survey and your accompanying opinions are very important because you will be representing – in effect – as many as 500 other customers who might be similar to you, but have not been randomly selected to participate.

Questions?

The Mustel Group, an independent research company based in B.C., is assisting us to conduct this survey. If you have any questions about how to complete or return your survey, please contact Matt Shepherd, Project Manager at mshepherd@mustelgroup.com or toll-free at 1-866-742-2242.

If you have questions about why BC Hydro is conducting this research, please contact Marc Pedersen, Senior Evaluation Specialist at marc.pedersen@bchydro.com.

Please complete and return the survey by August 18, 2017.

The information gathered in this survey is being collected in furtherance of BC Hydro's electricity conservation mandate under the *Clean Energy Act*.

In consideration of privacy issues, do not reference any individuals' names in your responses.

Thank you for your participation and prompt response.

BC Hydro
333 Dunsmuir Street, Vancouver BC V6B 5R3
www.bchydro.com

Important…

Work your way through the survey from front to back, carefully following the applicable instructions. By doing so, you may be instructed to skip past some of the questions not relevant to you and your household.

Managing Electricity Use

1. Customer households can manage their consumption of electricity by changing behaviour, purchasing energy-efficient products, making energy-efficient home upgrades or by participating in conservation programs.

Assuming you wanted to do so, how easy or difficult is it for your household to manage its consumption of electricity?

☐1 Very easy
☐2 Somewhat easy
☐3 Somewhat difficult
☐4 Very difficult

☐99 Don't know

2. How much of an effort does your household currently make to manage its consumption of electricity?

☐1 A great deal of effort
☐2 A fair amount of effort
☐3 A little effort
☐4 No effort at all

☐99 Don't know

☐97 Not Applicable – there is little opportunity at this time to manage our household's consumption of electricity

3. Compared to three years ago, would you say your household is making more of an effort to manage its consumption of electricity, less of an effort, or has there been no change?

☐1 Much more of an effort
☐2 A little more of an effort
☐3 No change
☐4 A little less of an effort
☐5 Much less of an effort

☐99 Don't know

Electricity Prices

4. Please think about the amount of money your household pays for electricity every month, every two months, or even over the course of a year, and consider the benefits you receive in return.

Would you say that the amount of money your household pays for its consumption of electricity represents…

☐1 Excellent value for money
☐2 Good value for money
☐3 Fair value for money
☐4 Poor value for money
☐5 Very poor value for money

☐99 Don't know

5. Thinking of things in a slightly different way, would you say that BC Hydro's residential electricity prices are…

☐1 Much too high
☐2 Just a little too high
☐3 About right
☐4 Just a little too low
☐5 Much too low

☐99 Don't know

6. Compared to three years ago, do you think that BC Hydro's residential electricity prices have…

☐1 Increased a great deal
☐2 Increased just a little
☐3 Stayed about the same
☐4 Decreased just a little
☐5 Decreased a great deal

☐99 Don't know

7. Regardless of your household's current effort to manage its consumption of electricity, to what extent do BC Hydro's residential electricity prices serve as an incentive to your household to manage its consumption of electricity?

☐1 Major incentive
☐2 Minor incentive
☐3 No incentive at all

☐99 Don't know

Total Electricity Bill

8. How often do you look over your household's electricity bill (either the print version or the online version)?

☐1 At least once a month
☐2 Once every 2 months
☐3 Once every 3 months
☐4 Once every 4 to 6 months
☐5 Once or twice a year
☐6 Never – we just pay it

☐99 Don't know/not sure

9. For the following set of statements, please check (✓) the response option that most accurately reflects your agreement or disagreement with the statement.

		Strongly agree	Somewhat agree	Neither agree nor disagree	Somewhat disagree	Strongly disagree	Don't know
a.	I spend more time looking over other bills I receive than my BC Hydro bill.	☐1	☐2	☐3	☐4	☐5	☐99
b.	I have a good understanding of the factors that cause changes in my household's consumption of electricity.	☐1	☐2	☐3	☐4	☐5	☐99
c.	My BC Hydro bill is easy to understand.	☐1	☐2	☐3	☐4	☐5	☐99
d.	I usually pay my BC Hydro bill without looking over its consumption details.	☐1	☐2	☐3	☐4	☐5	☐99

10. Compared to three years ago, would you say the total dollar amount of your household's electricity bills have…

- ☐1 Increased a great deal
- ☐2 Increased just a little
- ☐3 Stayed about the same ⇒ **check the box, then skip to question 12**
- ☐4 Decreased just a little
- ☐5 Decreased a great deal

- ☐99 Don't know ⇒ **check the box, then skip to question 12**

11. Thinking about your response in question 10 above, which of the following statements do you believe describes the reason(s) for the change in the total dollar amount of your electricity bills over the past three years. (check all that apply)

- ☐1 I believe the change in our bills has been due to changes in the overall price we pay for electricity.
- ☐2 I believe the change in our bills has been due to changes in our consumption level.

- ☐99 Don't know/not sure

- ☐97 Not applicable – our electricity bills have 'stayed about the same' (your previous response to question 10)

12. Thinking of your own experience, to what extent does the total dollar amount of your electricity bills serve as an incentive to your household to manage its consumption of electricity?

- ☐1 Major incentive
- ☐2 Minor incentive
- ☐3 No incentive at all

- ☐99 Don't know

As a reminder…

- **Mail the completed survey in the postage paid envelope provided, or complete the electronic version by August 18.**
- **For completing your survey, you can enter your name into a draw for one of four $250 gift cards to the home improvement retailer of your choice.**
- **If you complete the survey online, your name will be entered in the draw one additional time. Also, if your survey is received (in the mail or submitted via the Internet) by August 8, your name will be entered in the draw one additional time.**
- **Official rules can be viewed online at: www.web-reseach-online.com/bchydro_rules.html**

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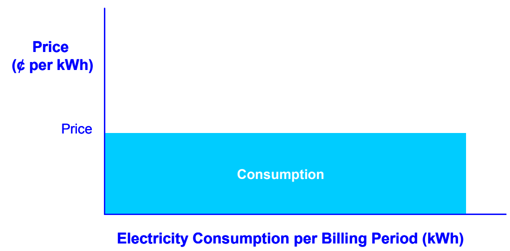
Rate Structures

In this section of the survey, we would like to explore your awareness and understanding of rate structures – that is, the various methods that can possibly be used to charge customers for their consumption of electricity, which is measured in kilowatt hours (kWh). Please review the four most common methods in the illustrations below.

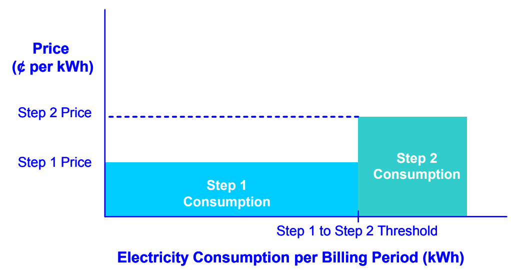
Flat Rate

1. **The price per kilowatt hour (kWh) of electricity is constant regardless of the amount of electricity used in a billing period.**



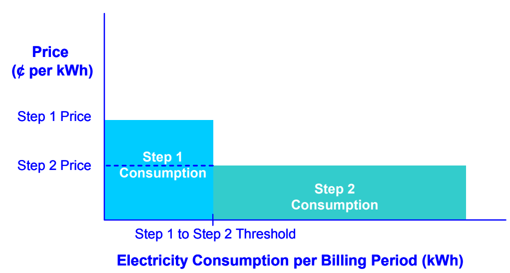
Inclining Block Rate / Stepped Rate

2. **The price per kilowatt hour (kWh) of electricity is lower for the first portion of electricity used, and steps up to a higher price for any additional consumption beyond a specified threshold in a billing period. The inclining block rate is also known as a stepped rate.**



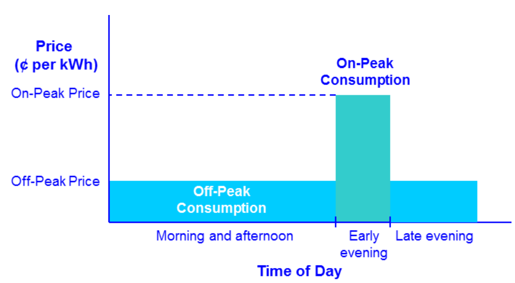
Declining Block Rate

3. **The price per kilowatt hour (kWh) of electricity is higher for the first portion of electricity used, and steps down to a lower price for any additional consumption beyond a specified threshold in a billing period.**



Time of Use Rate

4. **The price per kilowatt hour (kWh) of electricity varies by the time of day, typically higher during the early evenings than during all other hours of the day.**



You may review the explanation of rate structures and the accompanying illustrations on the adjacent page before proceeding with question 13.

13. Prior to receiving this survey, were you aware – in concept – of the flat rate method that can be used to charge customers for the consumption of electricity?

☐1 Yes
☐0 No

☐99 Don't know

14. Prior to receiving this survey, were you aware – in concept – of the inclining block rate (also known as a stepped rate) that can be used to charge customers for the consumption of electricity?

☐1 Yes
☐0 No

☐99 Don't know

15. Prior to receiving this survey, were you aware – in concept – of the declining block rate method that can be used to charge customers for the consumption of electricity?

☐1 Yes
☐0 No

☐99 Don't know

16. Prior to receiving this survey, were you aware – in concept – of the time of use rate that can be used to charge customers for the consumption of electricity?

☐1 Yes
☐0 No

☐99 Don't know

17. Prior to receiving this survey, which one of the four common methods did you believe BC Hydro currently uses for charging its residential customers for their consumption of electricity?

☐1 Flat rate (the price per kilowatt hour (kWh) of electricity is constant regardless of the amount of electricity used in a billing period)

☐2 Inclining block rate (also known as a stepped rate, the price per kilowatt hour (kWh) of electricity is lower for the first portion of electricity used, and steps up to a higher price for any additional consumption beyond a specified threshold in a billing period)

☐3 Declining block rate – (the price per kilowatt hour (kWh) of electricity is higher for the first portion of electricity used, and steps down to a lower price for any additional consumption beyond a specified threshold in a billing period)

☐4 Time of use rate – (the price per kilowatt hour (kWh) of electricity varies by the time of day, typically higher during the early evenings than during all other hours of the day)

☐99 Don't know/not sure

18. Thinking about your response to question 17 above – the method you believe BC Hydro currently uses for charging its residential customers – to what extent does the method serve as an incentive to your household to manage its consumption of electricity?

☐1 Major incentive
☐2 Minor incentive
☐3 No incentive at all

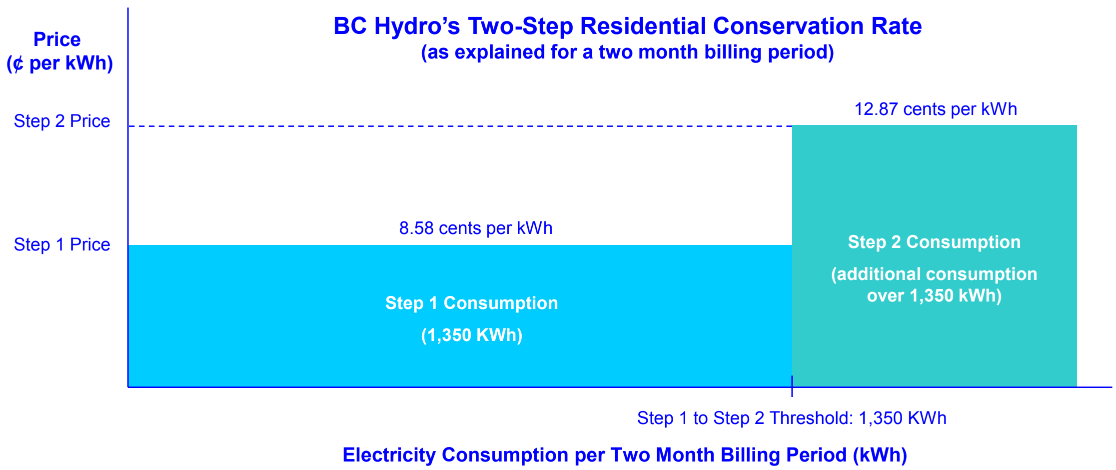
☐99 Don't know

BC Hydro's Residential Rate Structure

The method that BC Hydro charges its residential customers for their consumption of electricity is an inclining block rate – also known as a stepped rate.

Under this rate structure, customers who are billed every two months currently pay 8.58 cents per kilowatt hour (kWh) for the first 1,350 kWh used. This first portion is called Step 1. Above that amount, these households pay 12.87 cents per kWh for the balance of the electricity used during the billing period. This second portion is called Step 2. For customers billed on a monthly basis, the Step 1 to Step 2 threshold is set at 675 kWh, but with the same prices in the billing period as noted above.

This rate structure is designed to encourage conservation and, as such, some customers may also know it as the Two-Step Residential Conservation Rate.



Please read about the Two-Step Residential Conservation Rate – as above – before proceeding with question 19.

19. Which of the following statements best describes your awareness of BC Hydro's method of charging its residential customers for their consumption of electricity?

- ☐[1] Prior to this survey, I was fully aware that residential electricity consumption is charged on a stepped rate (also known as an inclining block rate).
- ☐[2] Now that it has been mentioned, I had heard that residential electricity consumption is charged on a stepped rate (also known as an inclining block rate).
- ☐[3] Prior to this survey, my understanding was that residential electricity consumption is charged on a flat rate.
- ☐[4] Prior to this survey, my understanding was that residential electricity consumption is charged on a declining block rate.
- ☐[5] Prior to this survey, my understanding was that residential electricity consumption is charged on a time of use rate.
- ☐[6] Prior to this survey, I did not know how residential electricity consumption is charged.
- ☐[99] Don't know

20. Having read a little more about the stepped rate method that BC Hydro uses for charging residential electricity consumption, how easy or difficult would you say it is to understand how the rate works?

- ☐[1] Very easy
- ☐[2] Somewhat easy
- ☐[3] Somewhat difficult
- ☐[4] Very difficult
- ☐[99] Don't know

21. How much of an understanding would you say you actually had – prior to receiving this survey – about the stepped rate method that BC Hydro uses for charging its residential customers?

- ☐[1] Excellent understanding
- ☐[2] Good understanding
- ☐[3] Fair understanding
- ☐[4] Poor understanding
- ☐[5] Very poor understanding

- ☐[99] Don't know

- ☐[97] Not applicable – I was not previously aware of the stepped rate method that BC Hydro uses ⇒ **check the box, then skip to question 30**

22. Although your household is charged the Step 1 price for its consumption of electricity up to 1,350 kWh in a two-month billing period and the Step 2 price for any additional consumption, you may not necessarily think about the price of electricity in this way as it applies to your own household.

How do you think about the price of electricity as it applies to your own household? (check only one)

- ☐[1] I would say that I consider the lower, Step 1 price as being my household's price of electricity in a billing period.
- ☐[2] I would say that I consider the higher, Step 2 price as being my household's price of electricity in a billing period.
- ☐[3] I would say that I consider each of the Step 1 and Step 2 prices being my household's price of electricity, depending on the point in time in the billing period and/or our consumption in the billing period.
- ☐[4] I do not think about my household's price of electricity in any of these particular ways.
- ☐[99] Don't know

23. Thinking of your own experience, to what extent does the stepped rate that your household's electricity is charged serve as an incentive to your household to manage its consumption of electricity?

- ☐[1] Major incentive
- ☐[2] Minor incentive
- ☐[3] No incentive at all **check the box, then skip to question 25**

- ☐[99] Don't know **check the box, then skip to question 25**

24. Which one of the following statements/scenarios best describes how the stepped rate incents your household to manage its consumption of electricity? (check only one)

- ☐[1] The lower, Step 1 price on its own incents our household: I consider the lower, Step 1 price as being the price applicable to all our electricity consumption in a billing period, and we try to manage our consumption of electricity on that basis.
- ☐[2] The higher, Step 2 price on its own incents our household: I consider the higher, Step 2 price as being the price applicable to the part of electricity consumption in a billing period that we have control over, and we try to manage our consumption of electricity on that basis.
- ☐[3] The difference between the Step 1 and Step 2 prices incents our household: If we can manage our consumption of electricity effectively in a billing period, we can have most of it charged at the lower, Step 1 price, perhaps even avoiding Step 2 consumption and the higher, Step 2 price altogether.
- ☐[4] The consumption threshold on its own incents our household: Regardless of the difference in the Step 1 and 2 prices and the amount we pay on our bill, we compare our household's consumption to the Step 1 to Step 2 threshold (675 kWh for monthly billing; 1,350 kWh for bi-monthly billing) simply because we like to keep our consumption as low as possible compared to the threshold.
- ☐[5] The stepped rate does not incent my household to manage its consumption of electricity in any of these particular ways.
- ☐[99] Don't know

25. Compared to three years ago, would you say your household is more mindful of its consumption of electricity in relation to the Step 1 and Step 2 prices and thresholds, less mindful, or has there been no change?

☐1 Much more mindful
☐2 Somewhat more mindful
☐3 No change
☐4 Somewhat less mindful
☐5 Much less mindful

☐99 Don't know

26. Customers can sign-up online to receive email notifications that will indicate when their consumption of electricity is halfway to reaching the higher Step 2 price in a billing period as well as when it has reached it.

Which of the following reflects your awareness and use of these Step 2 price alerts?

☐1 My household is currently signed-up to receive these alerts

☐2 I was previously aware of these alerts, but have never signed-up to receive them **check the box, then skip to question 28**

☐3 I was not previously aware of these alerts **check the box, then skip to question 28**

☐99 Don't know **check the box, then skip to question 28**

27. When your household receives Step 2 price alerts, does it typically make more of an effort to manage its consumption of electricity, less of an effort, or is there typically no change in effort?

☐1 Much more of an effort
☐2 A little more of an effort
☐3 No change
☐4 A little less of an effort
☐5 Much less of an effort

☐99 Don't know

☐97 Not Applicable – Our household has never received a Step 2 price alert

28. BC Hydro would like to understand if the stepped rate has been a factor in customer decisions to purchase any gas, oil or propane equipment/appliances instead of those that are powered by electricity.

For each gas, oil or propane equipment/appliance item listed, first indicate if your household has purchased one in the past three years. Next, for each item that you did purchase, indicate how much of a factor the stepped rate was – possibly, your desire to limit or avoid Step 2 electricity consumption – in your decision to purchase it as opposed to purchasing one powered by electricity.

If your household did not purchase any of the items, check here (   ), then skip to question 29.

			The stepped rate was a …			
Purchased in the past 3 years?	Yes, purchased		Major factor in the purchase decision	Minor factor in the purchase decision	No factor at all in the purchase decision	Don't know
a. Gas, oil or propane furnace	☐1	⇒	☐1	☐2	☐3	☐99
b. Gas range and/or gas cooktop	☐1	⇒	☐1	☐2	☐3	☐99
c. Gas, oil or propane water heater	☐1	⇒	☐1	☐2	☐3	☐99
d. Gas or propane fireplace	☐1	⇒	☐1	☐2	☐3	☐99
e. Gas or propane patio heater	☐1	⇒	☐1	☐2	☐3	☐99
f. Gas lawn mower	☐1	⇒	☐1	☐2	☐3	☐99

29. Prior to receiving this survey, were you aware that the stepped rate is designed to encourage the conservation of electricity?

☐[1] Yes
☐[0] No

☐[99] Don't know

30. Even though you may have just learned about it, overall, would you say you generally support the stepped rate method that BC Hydro uses to charge its residential customers for their consumption of electricity, oppose it, or are you indifferent about it?

☐[1] Strongly support
☐[2] Somewhat support
☐[3] Indifferent
☐[4] Somewhat oppose
☐[5] Strongly oppose

☐[99] Don't know

31. Thinking about your response to question 30 above, for what reasons do you feel that way? (In consideration of privacy issues, please do not reference any individuals' names.)

32. Compared to three years ago, would you say you have become more supportive of the stepped rate, more opposed to it, or has there been no change in your opinion?

☐[1] Much more supportive of it
☐[2] Somewhat more supportive of it
☐[3] No change
☐[4] Somewhat more opposed to it
☐[5] Much more opposed to it

☐[99] Don't know

☐[97] Not Applicable – I was not aware of the stepped rate three years ago or was not previously aware at all

Other Rate Structures

33. To address any changes in energy policy and objectives, BC Hydro may one day consider altering its method of charging residential customers for their consumption of electricity.

One option might be changing from the stepped rate to a flat rate whereby the price per kilowatt hour (kWh) of electricity is constant regardless of the amount of electricity used in a billing period.

Would you say you would generally support a flat rate, oppose it, or are you indifferent about it?

☐[1] Strongly support
☐[2] Somewhat support
☐[3] Indifferent
☐[4] Somewhat oppose
☐[5] Strongly oppose

☐[99] Don't know

Current In-Home Behaviours

In this section, BC Hydro would like to understand your behaviours related to electricity use in this home.

Please check (✓) the response option that best describes what you normally do when you are at the property at the service address as shown on the cover page of this booklet.

However, if you own the property but rent it out to tenants, or if the property typically goes unoccupied such as a pump house, then complete this section in regards to your behaviours in the home that you personally live in.

Be sure to check (✓) the 'Not Applicable' box if the statement does not apply to your household.

34. Lighting Behaviours

	Always	Usually	Occasionally	Never	Not Applicable
a. Only have the minimum number of lights on in a room for what I am doing	☐1	☐2	☐3	☐4	☐97
b. Turn off lights when no one is in the room	☐1	☐2	☐3	☐4	☐97
c. Purchase the most energy-efficient light bulbs, even if they are more expensive	☐1	☐2	☐3	☐4	☐97

35. Space Heating Behaviours (during winter months)

Check the 'Not Applicable' box in row e if you do not have a dog or cat.

	Always	Usually	Occasionally	Never	Not Applicable
a. Use a communicating/programmable thermostat or manually turn down the heat at night	☐1	☐2	☐3	☐4	☐97
b. Use a communicating/programmable thermostat or manually turn down the heat when no one is home	☐1	☐2	☐3	☐4	☐97
c. Reduce temperature in unused rooms by closing vents or turning down thermostats	☐1	☐2	☐3	☐4	☐97
d. Dress more warmly in cold weather and reduce/keep the thermostat to 20° Celsius (68° Fahrenheit) or below	☐1	☐2	☐3	☐4	☐97
e. Maintain the temperature of your home specifically for your dog(s) or cat(s) when no one is home	☐1	☐2	☐3	☐4	☐97

36. Space Cooling Behaviours (during summer months)

If this home does not have air conditioning, check here ( ), then skip to question 37.

	Always	Usually	Occasionally	Never	Not Applicable
a. Have the air conditioning come on only when it is 26° Celsius (79° Fahrenheit) or higher during the summer to save energy	☐1	☐2	☐3	☐4	☐97
b. Draw the window coverings during hot weather to reduce heat in the dwelling	☐1	☐2	☐3	☐4	☐97
c. Clean the air conditioning filter and coils at least once per season	☐1	☐2	☐3	☐4	☐97
d. Cool only the rooms to be occupied rather than the whole home	☐1	☐2	☐3	☐4	☐97
e. Use air conditioning only when very hot and natural ventilation is insufficient	☐1	☐2	☐3	☐4	☐97

37. Please indicate the location of the laundry appliances that your household typically uses.

☐[1] In my own home
☐[2] In a laundry room in another part of my building (i.e., the laundry appliances are shared with other suites)
☐[3] In another building or at a laundry business

38. Laundry Behaviours (please complete the table below regardless of where you do your laundry)

	Always	Usually	Occasionally	Never	Not Applicable
a. Only do laundry with full loads	☐[1]	☐[2]	☐[3]	☐[4]	☐[97]
b. Use cold water wash & rinse when doing laundry	☐[1]	☐[2]	☐[3]	☐[4]	☐[97]
c. Clean the lint filter before drying clothes	☐[1]	☐[2]	☐[3]	☐[4]	☐[97]
d. Use the temperature/moisture sensor to turn off the dryer rather than use the timer	☐[1]	☐[2]	☐[3]	☐[4]	☐[97]
e. Hang clothes to dry rather than machine dry	☐[1]	☐[2]	☐[3]	☐[4]	☐[97]

39. Dishwasher Behaviours

If the home does not have an automatic dishwasher, check here ( ), then skip to question 40.

	Always	Usually	Occasionally	Never	Not Applicable
a. Only turn on the dishwasher when it is full	☐[1]	☐[2]	☐[3]	☐[4]	☐[97]
b. Air dry the dishes in the dishwasher rather than use the dry cycle	☐[1]	☐[2]	☐[3]	☐[4]	☐[97]

40. Water Use Behaviours

Check the 'Not Applicable' box in row 'a' if the home does not have its own water heater.

	Always	Usually	Occasionally	Never	Not Applicable
a. Turn off the water heater when no one is in the home for more than 2-3 days	☐[1]	☐[2]	☐[3]	☐[4]	☐[97]
b. Keep shower times to no more than 5 minutes each	☐[1]	☐[2]	☐[3]	☐[4]	☐[97]

41. Plug Load Behaviours

Check the 'Not Applicable' box if the home does not have the item.

	Always	Usually	Occasionally	Never	Not Applicable
a. Turn off the TV when no one is in the room or actively watching a program	☐[1]	☐[2]	☐[3]	☐[4]	☐[97]
b. Turn off the computer and printer when not in use OR use the power-save mode	☐[1]	☐[2]	☐[3]	☐[4]	☐[97]

42. How often do you perform the following actions?

	Always	Usually	Occasionally	Never	Not Applicable
a. Pay more for products that are environmentally friendly	☐[1]	☐[2]	☐[3]	☐[4]	☐[97]
b. Think about ways to save energy	☐[1]	☐[2]	☐[3]	☐[4]	☐[97]

Attitudes toward Electricity and the Environment

For the following sets of statements, please check (✓) the response option that most accurately reflects your agreement or disagreement with the statement.

43. This first set of statements relate to your awareness and opinion of energy conservation as an issue.

	Strongly agree	Somewhat agree	Neither agree nor disagree	Somewhat disagree	Strongly disagree	Don't know
a. I have a good understanding of the reasons given for conserving electricity in this province.	☐1	☐2	☐3	☐4	☐5	☐99
b. I am in support of the reasons given for conserving electricity in this province.	☐1	☐2	☐3	☐4	☐5	☐99
c. We could all use a lot less energy than we do and if many people conserved, we could all make a big difference overall.	☐1	☐2	☐3	☐4	☐5	☐99
d. I am knowledgeable about ways to save electricity around my home.	☐1	☐2	☐3	☐4	☐5	☐99

44. These statements relate to your habits around electricity and conservation.

	Strongly agree	Somewhat agree	Neither agree nor disagree	Somewhat disagree	Strongly disagree	Don't know
a. I am an active energy conserver who looks for opportunities to save energy in everything I do.	☐1	☐2	☐3	☐4	☐5	☐99
b. Conserving energy is second nature to me – I've always done it, and know how to do it.	☐1	☐2	☐3	☐4	☐5	☐99
c. When I do make efforts to conserve electricity at home, it is more about saving money on my bill than helping to save the environment.	☐1	☐2	☐3	☐4	☐5	☐99
d. By making my home more energy-efficient, I am helping to do my part for the environment.	☐1	☐2	☐3	☐4	☐5	☐99

45. These final four statements are a mixture of issues.

	Strongly agree	Somewhat agree	Neither agree nor disagree	Somewhat disagree	Strongly disagree	Don't know
a. Climate change is a serious problem.	☐1	☐2	☐3	☐4	☐5	☐99
b. I really do not care much about energy and see little reason to conserve.	☐1	☐2	☐3	☐4	☐5	☐99
c. I believe my household's usage of electricity is currently at or near its lowest possible level.	☐1	☐2	☐3	☐4	☐5	☐99
d. Regardless of whether it makes a difference, everyone has a moral obligation to do the best they can to conserve energy.	☐1	☐2	☐3	☐4	☐5	☐99

Your Relationship to the Property

Important…

In these next sections of this survey, when we ask about your home, we are referring to the area covered by your BC Hydro bill at the service address as shown on the cover page of this booklet.

For some customers, this service address pertains to a seasonal home, a rental property or even an unoccupied structure such as a pump house rather than a primary residence. Whatever the case may be, please ensure your survey responses are in relation to the service address as shown on the cover page of this booklet.

46. Please indicate (✓) which of the following best describes your relationship to the property located at the service address as detailed on the cover page.

- ☐1 I (co)own and live (full-time or part-time) in the property at this service address
- ☐2 I (co)own and live in this Co-op property at this service address
- ☐3 I (co)own the property at this service address, but rent it out to tenants
- ☐4 I am a renter living in the property at this service address
- ☐98 Other (please specify): ____________________________

47. Regardless of whether it is owner or renter occupied, what type of residence is this property? (check only one)

- ☐1 Primary residence
- ☐2 Seasonal, vacation or weekend residence
- ☐98 Other (please specify): ____________________________

48. How many weeks or months in 2016 was this property left completely unoccupied?

______ weeks OR ______ months **if 0 weeks unoccupied in 2016, then check this box:** ☐0 0 weeks

49. Who is the BC Hydro account holder associated with the property at the service address?

- ☐1 Property owner(s)
- ☐2 Renter(s)
- ☐98 Other (please specify): ____________________________

50. Do you (or your landlord) pay maintenance fees to a building management company or a strata corporation in regards to this property?

- ☐1 Yes
- ☐0 No
- ☐99 Don't know

51. If you pay rent or maintenance fees, which of the following are included? (check all that apply)

- ☐1 Heat
- ☐2 Hot water
- ☐3 Natural gas for fireplace
- ☐4 Natural gas for cooking
- ☐5 Rent or maintenance fees are paid in regards to this property, but none of these items are included
- ☐97 Not Applicable – rent or maintenance fees are not paid in regards to this property
- ☐99 Don't know

About the Home Structure

52. What type of home structure is this? (located at the service address as detailed on the cover page)

- ☐[1] Single detached house
- ☐[2] Duplex
- ☐[3] Row/townhouse (3 or more units attached, each with separate entrance)
- ☐[4] Apartment/condominium
- ☐[5] Mobile home/manufactured home

- ☐[98] Other (please specify): ____________________________

53. When was this home built?

- ☐[1] Before 1950
- ☐[2] 1950-1975
- ☐[3] 1976-1985
- ☐[4] 1986-1995
- ☐[5] 1996-2005
- ☐[6] 2006-2015
- ☐[7] 2016-2017

- ☐[99] Don't know

54. What is the total floor area of this home? Include all floors covered by your BC Hydro bill, the basement and unfinished areas. Exclude the garage/carport and all other floors of apartment/condominium buildings.

_______________ square feet OR _______________ square meters ☐[99] Don't know

55. Does your BC Hydro bill cover only your household, or are there other households or suites on the same account?

- ☐[1] My household only
- ☐[2] Other households or suites as well ⇒ How many other households or suites? _______________

56. Which of the following energy efficiency upgrades – if any – has your household completed at the service address in the last three years? (check all that apply)

- ☐[1] Door upgrades
- ☐[2] Draft proofing upgrades
- ☐[3] Insulation upgrades
- ☐[4] Window upgrades
- ☐[5] Air source heat pump installation/upgrade
- ☐[6] Ground source heat pump installation/upgrade
- ☐[7] Furnace installation/upgrade
- ☐[8] Hot water tank installation/upgrade

- ☐[98] Other (please specify): ____________________________

- ☐[0] None of the above

- ☐[99] Don't know

Water Heating Equipment and Fuels

57. Please indicate (✓) the main type of hot water heating equipment in this home. (check only one)

If you live in an apartment or condominium, be sure to consider whether your water is heated by equipment in your own suite or by a central system located elsewhere in your building.

- ☐[1] Home does not have its own hot water equipment – the water is heated centrally elsewhere in the building and shared with other units

- ☐[2] Hot water tank (conventional storage tank)

- ☐[3] Heat pump water heater

- ☐[4] Tankless, on-demand water heater (not a small instant hot water dispenser in the kitchen)

- ☐[0] None – this property does not have access to running hot water

- ☐[99] Don't know

58. What is the main fuel used for the hot water heating equipment in this home?

- ☐[1] Electricity
- ☐[2] Natural gas
- ☐[3] Oil
- ☐[4] Wood
- ☐[5] Bottled or tanked propane
- ☐[6] Piped-in propane
- ☐[7] Solar

☐[98] Other (please specify): ____

☐[99] Don't know

☐[97] Not applicable – the home does not have its own hot water equipment

Home Heating Systems and Fuels

59. What is the main system used to heat the home at the service address? (check only one)

- ☐[1] Both central forced air furnace AND electric baseboards *
- ☐[2] Forced air furnace – single fuel
- ☐[3] Forced air furnace – dual fuel (without a heat pump)
- ☐[4] Forced air furnace – with a heat pump (all-in-one unit)
- ☐[5] Electric baseboard(s)
- ☐[6] Electric fireplace
- ☐[7] Electric radiant ceiling(s) or floor(s)
- ☐[8] Electric portable heaters (including ceramic, infrared)
- ☐[9] Electric wall heater(s)
- ☐[10] Heat pump – air source (not with all-in-one furnace)
- ☐[11] Heat pump – ground source (not with all-in-one furnace)
- ☐[12] Hot water baseboard(s)
- ☐[13] Hot water radiator(s)
- ☐[14] Hot water radiant floor(s)
- ☐[15] Natural gas fireplace
- ☐[16] Wood stove / wood fireplace

☐[98] Other (please specify): ____________________

☐[99] Don't know

* Typically these homes have central heat on the main floor and electric baseboards upstairs and/or downstairs.

60. In the first column in the grid below, please indicate the main heating fuel used with the main heating system you specified in question 59. In the second column, please indicate any other heating fuels used in the home.

- **If the home's main heating system is 'both a forced air furnace and electric baseboards', then the fuel used for the furnace should be indicated as the main heating fuel (in the 1st column), and electricity should be indicated as the other heating fuel for the electric baseboards (in the 2nd column).**
- **Note that hot water is not a fuel. We're interested in what fuel is used to heat the hot water.**

	Main Heating Fuel (check only one in this column) ⇓	Other Heating Fuels (check all that apply in this column) ⇓
Electricity	☐[1]	☐[1]
Natural gas	☐[2]	☐[2]
Oil	☐[3]	☐[3]
Wood	☐[4]	☐[4]
Bottled or tanked propane	☐[5]	☐[5]
Piped-in propane	☐[6]	☐[6]
District energy fuel(s) (produced by municipality)	☐[7]	☐[7]
Other (please specify):____________________	☐[98]	☐[98]
No Other Fuels (home has only one fuel)		☐[0]
Don't know	☐[99]	☐[99]

You and Your Household

The collection of demographic information in this section serves two very important purposes. First, it assists us in determining the extent that the sample of completed surveys provides a representative cross-section of all residential customers. Second, the information allows a better understanding of how awareness levels, opinions and behaviours differ among certain groups of customers.

61. Your age is:

☐1 18 to 24 years of age
☐2 25 to 34
☐3 35 to 44
☐4 45 to 54
☐5 55 to 64
☐6 65 or older

62. You are:

☐1 Female
☐2 Male

63. Your education is:

☐1 Less than Grade 12
☐2 High school diploma
☐3 Some college, vocational or technical school
☐4 College, vocational or technical school graduate
☐5 Some university
☐6 University/graduate degree

64. Which of the following describe your current status? (check all that apply)

☐1 Employed/self-employed – full-time
☐2 Employed/self-employed – part-time
☐3 Homemaker
☐4 Retired
☐5 Unemployed
☐6 Student
☐7 Short-term or long-term disability

☐98 Other (please specify): ___________________________

65. Please indicate the number of people living in this household on a full-time basis, in the following age categories. Please include any boarders or renters who do not have a separate BC Hydro account.

If the service address on the cover page pertains to a seasonal dwelling, then complete the table below in relation to the time(s) of the year when the dwelling is typically occupied.

	Number of people
a. Children 0 - 5 years of age	_______
b. Children 6 - 12	_______
c. Young adults 13 - 24	_______
d. Adults 25 - 64	_______
e. Adults 65 or older	_______
f. Total	= __________

66. Please indicate the combined total income before taxes for your household in the last year. The reason we ask is that, in analyzing groups of customers, we often find that energy use is related to total household income.

Your income information will never be associated with your name or household in any analysis or reporting.

☐[1] Under $20,000	☐[7] $70,000 to under $80,000
☐[2] $20,000 to under $30,000	☐[8] $80,000 to under $90,000
☐[3] $30,000 to under $40,000	☐[9] $90,000 to under $100,000
☐[4] $40,000 to under $50,000	☐[10] $100,000 to under $110,000
☐[5] $50,000 to under $60,000	☐[11] $110,000 to under $120,000
☐[6] $60,000 to under $70,000	☐[12] $120,000 or over

☐[99] Prefer not to say

67. Do you or anyone in your household use the property at the service address for farm use where income is generated from agricultural production (crops and/or livestock)?

☐[1] Yes ⇒ If Yes: Is your property at this service address assessed as a farm for tax purposes? ☐[1] Yes ☐[0] No
☐[0] No

68. Does anyone in your household conduct business activities in the home either on a full-time or part-time basis?

☐[1] Yes, full-time
☐[2] Yes, part-time
If Yes: How many hours per week are business activities conducted in the home? ____ hours

☐[0] No

Suggestions?

69. Is there anything BC Hydro can do to make the Two-Step Residential Conservation Rate more effective in encouraging your household to manage its consumption of electricity efficiently and to conserve? (In consideration of privacy issues, please do not reference any individuals' names.)

Permission for Linkage to Account Consumption

70. A key objective of this survey is to collect the necessary information to assist in our evaluation of the Two-Step Conservation Rate, including how customers' consumption of electricity may vary with their awareness, understanding and attitudes toward the rate.

To facilitate this, it is important to analyze customers' consumption of electricity at their current address for the past year as well as the next year as a 'time series' of consumption data helps us to better control for year-to-year changes in the weather, the economy, etc.

Rather than asking you to estimate how much electricity your home has and will consume over these periods, BC Hydro's Evaluation department would like to access this information from your account history and link it to your responses in this survey. We will not access nor review any of your bill payment information.

☐1 Yes
☐0 No

Incentive Prize Draw

71. Please provide your name and contact information below if you wish to be entered into the draw for one of four $250 gift cards to a home improvement retailer of your choice.

You can view the official rules and regulations at www.web-reseach-online.com/bchydro_rules.html

	Name:	Telephone:	Email Address:
☐1 Yes ⇒	______________________	____________	______________________
☐0 No thanks			

Thank You!

Your time and effort in completing this survey is very much appreciated and will help in planning electricity services for your community and the province as a whole.

If you completed this survey in this booklet rather than online, please fold it in half and place it in the postage paid business reply envelope provided. Upon receiving your survey booklet via Canada Post, the Mustel Group will keypunch and compile your responses with those of other customers.

BC Hydro
Power smart

MUSTEL GROUP

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix BB

Fiscal 2018 Greenhouse Gas Reduction Regulation Annual Report

Fred James
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

July 27, 2018

GHG Reduction (Clean Energy) Regulation Reporting
Director, Communities and Transportation
Electricity and Alternative Energy Division
Ministry of Energy, Mines and Petroleum Resources
Email: GGRRReporting@gov.bc.ca

British Columbia Utilities Commission
GHG Reduction (Clean Energy)
Regulation Reporting

Email: commission.secretary@bcuc.com

RE: Ministry of Energy, Mines and Petroleum Resources (MEMPR or Ministry)
British Columbia Hydro and Power Authority (BC Hydro)
Greenhouse Gas Reduction (Clean Energy) Regulation Reporting
Fiscal 2018 Annual Report

BC Hydro writes to submit the Business Information and Declaration (Attachment 1), and the Fiscal 2018 Greenhouse Gas Reduction Regulation (**GGRR**) Annual Report (**Report**) (Attachment 2). The Report includes, where applicable, results for the period from April 1, 2017 to March 31, 2018 (**Fiscal 2018**) for BC Hydro's prescribed undertakings as defined in section 4 of the GGRR.

Under section 18 of the *Clean Energy Act*, a public utility implementing prescribed undertakings defined in the GGRR, must submit to the MEMPR a report respecting the prescribed undertaking. Specifically, section 18(5) states that "a report to be submitted under section (4) must include the information the minister specifies and be submitted in the form and by the time the minister specifies."

In April 2018, Ministry staff issued the GGRR reporting requirements. The reporting requirements state that an annual report is due by June 30, of each year. On June 28, 2018, BC Hydro notified the Ministry and the British Columbia Utilities Commission (**BCUC**) it was unable to meet the June 30, 2018 deadline, and that it expects to file the Report no later than July 31, 2018.

BC Hydro is redacting customer-specific information in this version of the Report. An un-redacted version of the Report is being filed with the Ministry and BCUC only under separate cover.

BC Hydro
Power smart

For further information, please contact Geoff Higgins at 604-623-4121 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

cu/ma

Enclosure (1)

Greenhouse Gas Reduction (Clean Energy) Regulation Reporting

Attachment 1

Business Information and Declaration

Business Information and Declaration

<table>
<tr><th>Full Legal and Operating Name</th><th>Address Including Postal Code and Email</th><th>Telephone</th></tr>
<tr><td>British Columbia Hydro and Power Authority</td><td>333 Dunsmuir Street,
Vancouver BC V6B 5R3</td><td>604-623-4046</td></tr>
<tr><td>Reporting Period:</td><td colspan="2">April 1, 2017 to March 31, 2018 (Fiscal 2018)</td></tr>
<tr><td colspan="3">I understand that the information in this report is collected for the purposes of administering the Greenhouse Gas Reduction (Clean Energy) Regulation under the authority of the Clean Energy Act and section 26 of the Freedom of Information and Protection of Privacy Act.

I certify that records evidencing each matter reported under the Greenhouse Gas Reduction (Clean Energy) Regulation (the Regulation) Reporting Requirements are available on request.

I certify that a record evidencing my authority to submit this report on behalf of the public utility is available on request.

I certify that the information in this report is true and complete to the best of my knowledge and I understand that I may be required to provide to the Ministry of Energy, Mines and Petroleum Resources or the Commission records evidencing the truth of that information.</td></tr>
<tr><th>Signature of Authorized Signing Authority</th><th>Name and Title of Authorized Signing Authority (please print)</th><th>Date Signed YYYY/MM/DD</th></tr>
<tr><td></td><td>Fred James
Chief Regulatory Officer</td><td>July 27, 2018</td></tr>
</table>

BC Hydro
Power smart

Greenhouse Gas Reduction (Clean Energy) Regulation Reporting

Attachment 2

Fiscal 2018 Annual Report No. 1

April 1, 2017 to March 31, 2018

PUBLIC

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List of Tables

1 Executive Summary

This is BC Hydro's first annual report regarding its programs and projects that are "prescribed undertakings" under the *Clean Energy Act* (**CEA**). It is provided in response to the April 2018 "British Columbia Greenhouse Gas Reduction (Clean Energy) Regulation Reporting Requirements" provided to BC Hydro by the Ministry of Energy, Mines and Petroleum Resources. The report covers the period from April 1, 2017 to March 31, 2018 (**Fiscal 2018**).

BC Hydro provided supporting resources for three Low Carbon Electrification (**LCE**) Demand-Side Management (**DSM**) studies which were completed in Fiscal 2018. These studies are expected to contribute towards customers' business cases for project implementation, as well as provide key inputs on barriers, costs, and benefits that BC Hydro will consider in future program development and design. As reported in Table 2, the actual expenditure for LCE DSM in Fiscal 2018 was $0.22 million.

BC Hydro also made significant progress on the Peace Region Electricity Supply (**PRES**) Project. In Fiscal 2018, actual expenditure on the PRES Project was $10.7 million in the period with a cumulative cost of $21.5 million over the life of the project.

In all cases, it is premature to report any avoided greenhouse gas emissions or ratepayer impacts.

2 State of the Market and Program Planning

2.1 Background

British Columbia's Climate Leadership Plan sets out actions to enable the Province to meet its greenhouse gas (**GHG**) emission targets by 2050. Among other things, the plan calls for BC Hydro to make investments in infrastructure to power natural gas production projects with clean electricity and to initiate programs to encourage customers to switch from fossil fuels to electricity in order to reduce greenhouse gas (**GHG**) emissions.

In August 2017, the Minister's Mandate Letter to BC Hydro included an expectation for BC Hydro to continue to provide leadership in advancing the government's climate action strategies, through fuel switching and electrification initiatives in the transportation, oil and gas, and other sectors; initiatives to further reduce emissions in the transportation sector; and policies and programs to increase the energy efficiency of buildings. This expectation has also been reiterated in the April 2018 Minister's Mandate Letter to BC Hydro.

Subsection 18(1) of the CEA empowers the Lieutenant Governor in Council to prescribe, by regulation, classes of undertakings for the purpose of reducing GHG emissions. Public utilities that choose to engage in undertakings that are within one or more prescribed class of undertaking are assured of being able to recover the costs of the undertaking in their rates, and may not be prevented by the Commission from engaging in the undertaking. The Greenhouse Gas Reduction (Clean Energy) Regulation (**GGRR**) was first issued in 2012, but was amended in 2017 to include eight new classes of electrification undertakings. Together, CEA section 18 and the GGRR provide one of the statutory pillars of the Province's GHG emission reduction policy.

The eight new classes of electrification undertaking prescribed by GGRR section 4 can be divided into two broad categories: those that are program based, similar to BC Hydro's demand-side management programs,[1] and those that are infrastructure based.[2] BC Hydro refers to its undertakings that fall within one of the classes in the former category as LCE DSM Project/Programs, and to its undertakings that fall within one of the classes in the latter category as LCE Infrastructure Projects. This

[1] Being the classes of undertaking prescribed by subsections 4(3)(a)(i); 4(3)(a)(ii); 4(3)(b)(i); 4(3)(b)(ii); 4(3)(c) and 4(3)(d) of the GGRR.

[2] Being the classes of undertaking prescribed by subsections 4(2) and 4(3)(e) of the GGRR.

nomenclature corresponds to the "Electrification Programs" referred to in subsection 6.8 of the GGRR Reporting Requirements, and "Transmission, Distribution and Generation" referred to in subsection 6.9 of the GGRR Reporting Requirements, respectively.

As noted, one of the legal consequences of the public utility program or project being a "prescribed undertaking" is that the public utility is entitled to recover the costs of the program or project in its rates. That legal consequence is meaningful only if the costs associated with particular programs and projects that are prescribed undertakings can be identified and thus are accounted for by the public utility.[3] Accordingly, the prescribed undertakings described in this Fiscal 2018 GGRR Annual Report are those programs and projects with recorded costs in Fiscal 2018.

2.2 State of the Market Discussion

The GGRR Reporting Requirements ask for a "state of the market" discussion that includes consideration of program data, performance metrics, underlying assumptions regarding the metrics, ratepayer impacts and environmental benefits. As Fiscal 2018 is the first year in which it is contemplated by the GGRR that public utilities would engage in electrification undertakings, BC Hydro has little aggregated or generalized information to provide; such information as it currently has on these topics is set out in the LCE DSM Project/Program and LCE Infrastructure Project discussions which follow. However, BC Hydro can say, generally, that it is forecast to be in an energy surplus position until Fiscal 2033. During this surplus period, the LCE-driven incremental electricity sales will increase BC Hydro’s revenues and can make rates lower than they otherwise would have been due to the expected positive differential between domestic electricity rates and forecast export prices. Such incremental electricity sales are also expected to reduce GHG emissions from what they otherwise would have been, thus having an environmental benefit.

[3] BC Hydro notes that the costs it incurs in regard to its LCE DSM Project/Programs are all deferred to the DSM Regulatory Account, pursuant to Order in Council No. 100, issued March 1, 2017. Generally, the costs it incurs in regard to its LCE Infrastructure Programs are capitalized.

The GGRR Reporting Requirements also requests a report by a Fairness Advisor on the competitiveness of any call process held during the reporting period. BC Hydro confirms that in Fiscal 2018 it did not hold any call processes in regard to its LCE DSM Project/Programs or its LCE Infrastructure Projects.

3 LCE DSM Project/Programs

3.1 Overview

BC Hydro is leveraging over 25 years of experience in conservation-focussed DSM and its substantial knowledge about market transformation, customer barriers, and market response to develop cost-effective LCE DSM Project/Programs. It is envisioned that BC Hydro's LCE DSM Project/Programs will fall within three customer sectors – residential, commercial, and industrial - with a focus on opportunities in industrial process, transportation, and space heating.

3.2 Fiscal 2018 LCE DSM Project/Programs

In Fiscal 2018, BC Hydro incurred expenditures in regard to three LCE DSM Project/Programs as described below. There were five additional projects with which BC Hydro made preliminary funding commitments of approximately $30.5 million, but there are no expenditures in BC Hydro's financial reporting for Fiscal 2018. As such, these expeditures will be detailed in future GGRR reports.

(i) [redacted]

[redacted] has been investigating options that would allow them to produce a wide variety of new products. As part of this exploration an assessment of process heating requirements was completed. Process heating is typically supplied by natural gas or propane. This study investigated if an opportunity exists to use electricity in place of fossil fuels. The study was completed and found that pilot testing and further analysis would be required to determine if electrification would be a viable option. The electrification study was an undertaking within the class of prescribed undertakings set out in section 4(3)(c) of the GGRR.

(ii) [redacted] The focus of this project was to explore low-carbon electrification [redacted] materials-handling methods. The current materials-handling method for [redacted] removal involves use of diesel fueled equipment to remove the [redacted], and [redacted] trucks (diesel-fueled) to transport [redacted]. The project examined a potential electrified system to [redacted]. The study is complete and found that a reduction in carbon dioxide equivalent (CO2e) could be made. Based on the assessment in the study it was recommended to proceed with a detailed feasibility study to further develop the concepts and establish a preliminary design and corresponding capital cost estimate. It is also an undertaking within the class of prescribed undertakings set out in section 4(3)(c) of the GGRR.

(iii) [redacted] This [redacted] project was the first phase of investigations into ways low-carbon technologies could be introduced into the local transportation network to reduce carbon emissions. [redacted] refers to transporting goods [redacted] via (diesel-fueled) ground freight. The study is complete and found that there are many inherent challenges when considering the implementation and promotion of new technologies into the fragmented and competitive [redacted] However, it is recommended that the [redacted] continue to maintain a broad outlook towards each of the low-carbon technologies identified in the study as being suitable for reducing carbon in the [redacted] industry. It is also an undertaking within the class of prescribed undertakings set out in section 4(3)(c) of the GGRR.

(iv) BC Hydro Program Staff Labour: BC Hydro provided internal support resources to the three projects described above, as well as to other projects and programs under development or related to preliminary funding commitments for projects expected to be reported in future periods. The associated expenditures are an undertaking within the class of prescribed undertakings set out in section 4(3)(c) of the GGRR.

3.3 Verification Methods

Depending on the program, project or activity, there can be up to four distinct areas of activity that BC Hydro may use to review and verify electrification and emission reduction estimates. These are technical review, site inspection, measurement and verification, and evaluation. Results from each area will be used in project and contract management to ensure that BC Hydro receives the expected project benefits. BC Hydro will be selective in the use of these processes, and focus its efforts where warranted to improve the accuracy of estimates and reduce exposure to risk. This approach will mirror BC Hydro's current approach to demand-side management electricity savings, and provide estimates for both additional electricity demand and greenhouse-gas emission reductions. BC Hydro will provide details of its verification efforts in future annual reports when they are employed.

3.4 Performance Metrics

The LCE DSM Projects/Programs described above were studies into the use of electrical technology, and the expenditures associated with supporting resources. Such studies are critical in enabling customers to build the business case for project implementation as well as providing key inputs on barriers, costs, and benefits into program development and design. Performance metrics for these studies include the following elements:

1. Yield information which could inform and improve accuracy of the project modeling assumptions;

2. Yield information which could inform and improve understanding of market barriers and customer drivers; and
3. Yield site specific investigation and engineering analysis at a level sufficient to determine if advancing the project would provide tangible benefits that would make business sense for the customer and BC Hydro to continue supporting the project.

The three studies were completed in Fiscal 2018 and the associated supporting resources met these performance metrics.

3.5 Cost-Effectiveness

Undertakings are in a class of undertakings prescribed by subsections 4(3)(a) to 4(3)(b) of the GGRR if they satisfy a cost-effectiveness test defined in subsection 4(1) of the GGRR. That cost-effectiveness test requires that each undertaking that is an undertaking within the class of undertakings prescribed by subsections 4(3)(a) or 4(3)(b) of the GGRR must have a positive net present value (**NPV**), with the measure of a program's NPV being that of all of the programs that fall within the class of undertakings described in subsections 4(3)(a) and 4(3)(b) of the GGRR. Furthermore, the GGRR cost-effectiveness test is measured only at the time BC Hydro decides to carry out the program. The cost-effectiveness test in the GGRR is not applicable to this Fiscal 2018 Annual Report as BC Hydro did not incur expenditures in regard to any undertaking defined by a class of undertakings in subsections 4(3)(a) to (b) of the GGRR in Fiscal 2018. There is no other cost-effectiveness test applicable to prescribed undertakings.

3.6 Results Table - Explanation of Terms

Table 1 includes a description of the information provided in Table 2 below in regard to LCE DSM Projects/Programs.

Table 1 LCE DSM Project/Program Results Table: Explanation of Terms

Column	Heading	Descriptions
A	GGRR	Applicable section of the GGRR
B	Project / Program/Contract / Expenditure	Low-carbon electrification activities to encourage or enable the use of electricity in place of other sources of energy that produce more greenhouse gas emissions.
C	Actual Cost ($ million)	Costs incurred at the end of the current reporting fiscal
D	Cost Effectiveness ($ million): NPV to 2030 (Fiscal 2031)	The present value of the costs and benefits are determined using a discount rate equal to BC Hydro's weighted average cost of capital. The present value of the costs are subtracted from the present value of the benefits from the project start year to last year in the calculation period (Fiscal 2031) to determine the net present value for the project.
E	Cost Effectiveness ($ million): GGRR NPV to 2030 (Fiscal 2031)	The calculation of the GGRR NPV is based on costs and benefits as defined in the GGRR. Per that definition, benefits mean **all** revenues BC Hydro expects to earn as a result of implementing LCE programs falling under subsections 4(3)(a) or 4(3)(b), less revenues that would have been earned from the sale of that electricity to export markets. Costs mean **all** the costs BC Hydro expects to incur to implement LCE programs falling under subsections 4(3)(a) or 4(3)(b), including development and administration costs.
F (i)	Actual: Additional Energy Consumption (MWh/year)	The average annual additional energy consumption estimated to be delivered from the project in the current reporting fiscal period.
F (ii)	Cuml.: Additional Energy Consumption (MWh/year)	The sum of the successive average annual additional energy consumption estimated to be delivered from the project as at the end of the reporting fiscal period.
G (i)	Actual: Additional Capacity Demand (MW)	The total energy demand added
G (ii)	Cuml.: Additional Capacity Demand (MW)	Sum of the successive energy demand addition
H (i)	Actual: Estimated GHG Emission Reductions (tonnes CO2e/year)	The average annual tonnes per year of carbon dioxide equivalent reductions from the project in the current reporting fiscal period.
H(ii)	Cuml.: Estimated GHG Emission Reductions (tonnes CO2e/year)	The sum of the successive additional average annual tonnes per year of carbon dioxide equivalent reductions from the project as at the end of the reporting fiscal period.

3.7 Results Table

Table 2 summarizes information regarding the three LCE DSM Programs/Projects that are prescribed undertakings as described above. The reasons for the numerous indications of "n/a" is due to the nature of the projects, as described above. The GGRR Reporting Requirements requests graphical depictions (e.g., pie charts or bar charts) of the distribution by region in the Province and the distribution by customer sector where possible. Given that the Fiscal 2018 LCE DSM Programs/Project volume consisted of three projects, it was determined that a graphical depiction may not be meaningful and as such was not included in this report. In future years with a larger number of LCE DSM Programs/Projects, meaningful graphical depictions can be developed and included.

Table 2 Electrification Information for LCE DSM Projects/Programs for Year Ending March 31, 2018

	A	B	C	D	E	F		G		H	
	GGRR	**Project/Program/Contract/Expenditure**	**Actual Cost ($ million)**	**Cost Effectiveness ($ million)**		**Additional Energy Consumption (MWh/year)**		**Additional Capacity Demand (MW)**		**Estimated GHG Emission Reductions (tonnes CO2e/year)**	
				NPV to 2030 (Fiscal 2031)	**GGRR NPV to 2030 (Fiscal 2031)**	**Actual (i)**	**Cuml. (ii)**	**Actual (i)**	**Cuml. (ii)**	**Actual (i)**	**Cuml. (ii)**
1	4(3)(c)	[redacted]	0.08	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2	4(3)(c)	[redacted]	0.01	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
3	4(3)(c)	[redacted]	0.01	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
4	4(3)(c)	BC Hydro Program Staff Labour	0.12	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
		Total	**0.22**								

4 LCE Infrastructure Projects

4.1 Overview

Northeast British Columbia is forecasted to experience a significant increase in natural gas production and processing primarily in the Montney region. In the absence of adequate electricity supply, much of this development will be powered by natural-gas fired production processes. Meanwhile, BC Hydro's local and area transmission system in this region is constrained. Further, the transmission system's ability to supply new loads in the South Peace region at all, even with a reduced level of reliability, is expected to be exceeded in summer 2021. Accordingly, BC Hydro will construct and operate new transmission and distribution facilities, and/or provide for temporary generation pending the completion of such facilities, to avoid incremental GHG.

4.2 Fiscal 2018 LCE Infrastructure Projects

As of March 31, 2018, the only infrastructure project for which BC Hydro has incurred expenditures for the purpose of reducing GHG emissions is the Peace Region Electricity Supply (**PRES**) Project. BC Hydro has also entered into an agreement valued at about $12 million with respect to temporary generation facilities until the PRES Project is in service, but there were no expenditures incurred or recorded in Fiscal 2018 in that regard. Expenditures incurred and recorded in future fiscal years will be described in the applicable future GGRR annual report.

The PRES Project is in the South Peace region of British Columbia. The PRES Project consists of two parallel 230 kV transmission lines that will connect the future Site C South Bank substation to the existing Shell Groundbirch substation using mainly wood pole construction and upgrades at each station. The proposed transmission lines will be 58 km long. As of March 31, 2018, BC Hydro has incurred $21.5 million in capital expenditures on developing the PRES Project, of which $10.7 million was incurred in Fiscal 2018. During Fiscal 2018, the PRES Project team carried out a detailed investigation of the preferred alternative and began the process of securing required licences and permits to be able to advance this project to the construction stage.

The PRES Project will enable natural gas producers and processors to electrify their existing and new operations, rather than self-supplying with natural gas. This includes natural gas producers and processors as defined in GGRR paragraphs 4(2)(a)(i) and (ii). The PRES Project will reduce greenhouse gas emissions in British Columbia.

As of March 31, 2018, BC Hydro had not yet determined whether the PRES Project should proceed to implementation. The PRES Project was approved by BC Hydro's Board of Directors for implementation in June 2018 and has an expected in-service date prior to December 31, 2022. Therefore, it is a prescribed undertaking pursuant to GGRR section 4(2).

4.3 Quantitative Data – Methodology & Assumptions

BC Hydro has developed criteria to qualify customer loads for inclusion in its estimates for GHG emissions reduced or avoided due to the PRES Project. To qualify the customer load:

- Must be a new natural gas processing plant (including associated gas gathering and wellpad facilities) or existing plant converting to take grid service which takes, or commits to take, electricity service from BC Hydro in Fiscal 2018 or later;
- Would have used natural gas for power supply in the absence of BC Hydro's commitment to construct and operate new facilities; and
- Will be served by the PRES Project once it is placed in service.

4.4 Performance Metrics

The GGRR performance metrics for the PRES Project are listed in Table 3 below.

Table 3 PRES Project: GGRR Performance Metrics

Type of Facility	Project(s)	Performance Metrics
Transmission & Distribution	PRES Project	1. New load served 2. GHG Emissions Reduction

A key benefit of the PRES Project is to provide a clean, reliable source of electrical power supply to existing and new natural gas processing operations. In the absence of PRES, there would be no grid service alternative. These plant operations would otherwise need to use natural gas (or other fossil fuels) for power supply. Since greenhouse gases are emitted when fossil fuels are burned to create power, the PRES Project will reduce GHG emissions in British Columbia for any existing plant, or prospective new plant, that elects to take grid service rather than self-supply using natural gas. BC Hydro will estimate the impact the PRES Project will have on GHG emission reductions in British Columbia based on the assumptions and methodology set out below:

Assumptions

- The N-0 supply capability of the Dawson Chetwynd Area Transmission (DCAT) system, which currently serves customers in the South Peace region, is 413 MW;
- BC Hydro is unable to supply any new customer loads above this limit until the PRES Project is constructed;[4]
- For any customer load that elects to self-supply using natural gas, the average heat rate for gas-fired power is 10.0 GJ/MWh and the average emissions intensity factor is 518 tonnes per GWh;[5] and

[4] BC Hydro will use temporary generation to supply any new customer loads above the 413 MW limit of DCAT, prior to PRES being in-service.

- The average load factor for a natural gas processing plant is 85 per cent.

Methodology

- For every 100 MW of customer load, the average annual energy consumption is determined by the formula: 100 MW x 8,760hrs/year x 0.85 = 745 GWh/year
- For every 100 MW of customer load that makes the permanent decision to use natural gas for power supply rather than connect to the BC Hydro transmission system, the GHG emission impact is: 745 GWh/year x 518 tonnes GHG per GWh = 385,910 tonnes GHG/year
- Assuming an average operating plant life of 25 years, the total GHG emission impact for every 100 MW of load not served by BC Hydro is:
  385,910 tonnes GHG/year x 25 years = 9,647,750 tonnes GHG.

4.5 Results Table - Explanation of Terms

Table 4 includes a description of the information provided in the results table for LCE Infrastructure Projects. The reasons for the indications of "n/a's" is due to the nature of the PRES Project as of March 31, 2018, as described above.

[5] Average heat rate and emissions intensity represents the efficient operation of an LM6000 SCGT gas engine. Actual load-following heat rates and emissions for natural gas-fired power supply at a customer plant may differ.

Table 4 LCE Infrastructure Projects Results
Table: Explanation of Terms

Column	Heading	Descriptions
A	Prescribed Undertaking	Type of prescribed undertaking.
B	Name	Project, program, or customer name.
C (i)	Actual ($ million)	Actual costs in millions incurred at the end of the current reporting fiscal.
C (ii)	Cumulative Costs ($ million)	Cumulative actual costs in millions incurred from first year of expenditure to the end of the current reporting fiscal.
C (iii)	Forecast Total ($ million)	Transmission & Distribution: Total Definition phase estimated forecast cost range in millions (AACE class 4 estimate accuracy range).
D	Capacity of Facility (MW)	Planned facility capacity in megawatts at N-1 and N-0.
E	Total Capacity Committed/Secured (MW)	Cumulative total capacity committed and secured until the end of the current fiscal year in megawatts.
F	Total Customer Load(s) Served (MW)	Cumulative total customer loads served as at the end of the current fiscal year in megawatts.
G	Total Energy Provided to Customers (MW/h)	Cumulative total energy provided to customers as at the end of the current fiscal year in megawatts per hour.
H (i)	Actual: GHG Emissions Reduction Estimates (tonnes CO2e/year)	Actual GHG Emissions Reduction at the end of the current fiscal period in tonnes of carbon dioxide equivalent per year.
H (ii)	Cumulative: GHG Emissions Reduction Estimates (tonnes CO2e/year)	Cumulative GHG Emissions Reduction as at the end of the current fiscal period in tonnes of carbon dioxide equivalent per year.
I (i)	Type: Fossil Fuel(s) Avoided Or Displaced	Type of fossil fuels avoided or displaced or likely to be avoided or displaced.
I (ii)	Amount: Fossil Fuel(s) Avoided Or Displaced	Amount of fossil fuels avoided or displaced or likely to be avoided or displaced.

4.6 Results Table

Table 5 provides the results for LCE Infrastructure Projects with expenditures in Fiscal 2018 (i.e., the PRES Project).

Table 5 LCE Infrastructure Projects Results as of March 31, 2018

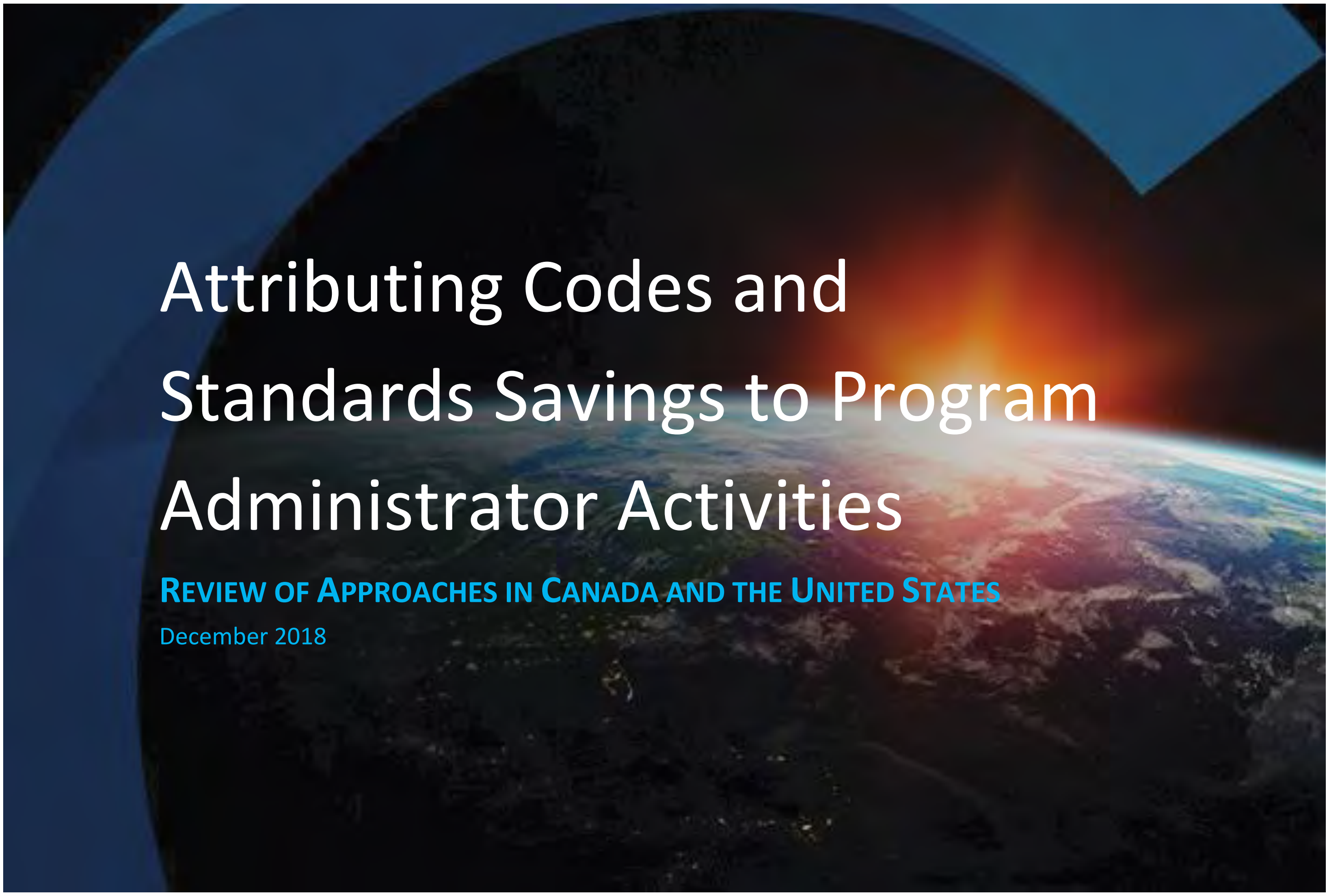
	A	B	C			D	E	F	G	H		I	
	Prescribed Undertaking	Name	Cost			Capacity of Facility (MW)	Total Capacity Committed/Secured (MW)	Total Customer Load(s) Served (MW)	Total Energy Provided to Customers (MW/h)	GHG Emissions Reduction Estimates (tonnes CO2e/yea)		Fossil Fuel(s) Avoided or Displaced	
			Actual ($ million) (i)	Cumul. ($ million) (ii)	Forecast Total ($ million) (iii)					Actual (i)	Cumul. (ii)	Type (i)	Amount (ii)
1	T&D	PRES Project	10.7	21.5	348.2 - 197.3	800 - 950	24	n/a	n/a	n/a	n/a	n/a	n/a

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix CC

Codes and Standards Attribution Report

CADMUS



Attributing Codes and Standards Savings to Program Administrator Activities

REVIEW OF APPROACHES IN CANADA AND THE UNITED STATES

December 2018

Prepared for:

BC Hydro

333 Dunsmuir Street, 5th Floor

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Prepared by:
Allen Lee
Jerica Stacey

CADMUS

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Abbreviations

Abbreviations	Description
ACC	Arizona Corporation Commission
AEGB	Austin Energy Green Building
APS	Arizona Public Service
ASAP	Appliance Standards Awareness Project
BC	British Columbia
BCUC	British Columbia Utilities Commission
BPU	Board of Public Utilities
CCEI	Compliance Enhancement Initiative
CCSI	Code Compliance Support Initiative
CEE	Center for Energy and Environment
CPUC	California Public Utilities Commission
C&S	Codes and Standards
DCEO	Department of Commerce and Economic Opportunity
DCRA	Department of Consumer and Regulatory Affairs
DCSEU	DC Sustainable Energy Utility
DER	Division of Energy Resources
DOEE	Department of Energy and Environment
DSM	Demand-Side Management
ECCCNYS	Energy Conservation Construction Code of New York State
EERS	Energy Efficiency Resource Standard
EVT	Efficiency Vermont
IECC	International Energy Conservation Code
IESO	Independent Electricity System Operator
IMT	Institute for Market Transformation
IOUs	Investor-Owned Utilities
LDCs	Local Distribution Companies
MEEA	Midwest Energy Efficiency Alliance
NECB	National Energy Code for Buildings
NEEA	Northwest Energy Efficiency Alliance
NEEP	Northeast Energy Efficiency Partnerships
NOMAD	Naturally Occurring Market Adoption
NTG	Net-to-Gross
NYSERDA	New York State Energy Research and Development Authority
OED	Office of Energy Development (Utah)
PA	Program Administrator
RNC	Residential New Construction
SBC	System Benefits Charge
SRP	Salt River Project
SWEEP	Southwest Energy Efficiency Partnership
TEP	Tucson Electric Power Company

Introduction and Methods

BC Hydro commissioned Cadmus to examine how various jurisdictions in North America attribute or determine the share of energy savings[1] to credit energy efficiency program administrators (PAs) for supporting codes and standards (C&S). This study is in response to a directive to BC Hydro from the B.C. Utilities Commission in their F2017-F2019 Revenue Requirements Application that asked BC Hydro to review the industry practice for attribution of C&S savings.

Program Administrators' Support for Codes and Standards

Building energy codes and appliance efficiency standards can offer cost-effective opportunities to produce significant energy-savings (Edison Foundation; Stellberg et al. 2012). Program Administrators (PAs), including utilities, are in a strong position to support C&S; however, without appropriate policies that credit PAs with savings, PAs are disincentivized from supporting C&S because this raises the baseline from which traditional programs' energy savings are derived (Cadmus et al. 2013; Drexler 2012; Cooper and Wood 2013).

Jurisdictions are recognizing the potential for PAs to support codes and standards in conjunction with developing policies that incentivize PAs to take the following actions:

- Support the adoption of new C&S by helping design new codes or standards, increasing the market share of energy-efficient products or practices through their programs and promoting the adoption of new C&S.
- Enhance compliance with and enforcement of new C&S by offering code training programs, supporting third-party inspectors and plan reviewers, spreading awareness, and listing and publicizing complying products (Cooper and Wood 2013).

Public utility commissions have an interest in ensuring that ratepayer dollars are spent on cost-effective programs and activities to influence the market, but adopting new C&S is a complex process that involves multiple stakeholders and key players.[2] Also, it is not always clear how much PAs impact the adoption of new regulations, and whether those regulations would have been adopted at the same time absent PA efforts. When PAs sponsor programs to support code and standard compliance, it may seem simple to attribute impacts since the PA is responsible for the program activities; yet, determining the share of savings credited to PA programs can be challenging due to multiple non-programmatic influences such as local enforcement efforts or building industry education campaigns. However, these

[1] Quantifying the energy impacts from codes and standards is beyond the scope of this study, although the attribution process is often closely related to the other steps for determining savings.

[2] Depending on the code or standard, stakeholders could include those from the federal government (Natural Resources Canada) or provincial government, energy efficiency advocates, the BC Association for Advancement of Conservation and Efficiency, nongovernmental organizations such as Pembina or Sierra Club, and other utilities such as FortisBC or FortisElectric.

non-programmatic influences are also increasingly complicating the determination of attribution for traditional utility programs "because multiple agents contribute to a decision-maker's awareness and deliberation; these agents are diffused throughout the community and are themselves subject to numerous influences, including program administrator efforts" (Peters and McRae 2008).

Industry Drivers for Attribution

As noted in subsequent sections, the involvement of PAs in C&S activities, as well as the interest in and methods for attributing energy savings to such activities, is changing over time. Several factors are influencing PAs to assess C&S savings and claim energy savings; however, the drivers for each PA can differ and often depend on the specific regulatory framework for each PA. These drivers include:

- *State and local legislated policy targets*. Energy savings targets for PAs, often included in a statewide energy efficiency resource standard (EERS), provide an incentive for PAs to claim C&S savings towards their energy reduction goals.[3]
- *Effect of more stringent C&S on program savings*. Existing codes and standards usually provide the baseline against which PA program savings are measured. As the stringency of codes and standards increases, the options for achieving savings targets through incentive programs decline. PAs can reduce this challenge if they are able to claim some of the C&S savings.
- *Cost-effectiveness of incentive programs*. A corollary of the effect of C&S on savings from incentive programs is the effect on cost-effectiveness. If conventional programs increase the market readiness for C&S, attributing part of the C&S savings to the programs could improve their cost-effectiveness. We are unaware of any jurisdiction where this has been implemented, though the California utilities have proposed considering it.
- *Accurate program savings and load estimation*. If C&S are used as the baseline for estimating incentive program savings but compliance is less than 100%, program savings and load forecasts will be inaccurate. In addition, C&S savings are estimated for the purpose of determining the net load forecast.
- *C&S program impact.* PAs are using attribution assessments to demonstrate the impact of code compliance support programs on code compliance and to estimate the energy savings resulting from increased code compliance. This effort highlights the importance of funding C&S programs.

British Columbia Context and the DSM Regulation

In British Columbia (BC), a key driver for determining C&S savings is to reflect the impact in the net load forecast. However, Section 4(1.4) of the Demand-Side Measures (DSM) regulation (Province of British Columbia, Utilities Commission Act 2008) provides that the British Columbia Utilities Commission (BCUC)

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[3] The California Public Utilities Commission has taken a unique position regarding savings from utility support of C&S. They have set specific savings targets for C&S separate from the rest of the portfolio. C&S program costs and benefits are not included in the overall cost-effectiveness calculation and utilities are awarded a given percentage management fee for their C&S advocacy activities.

may determine the cost-effectiveness of a measure proposed in an energy efficiency plan or portfolio by increasing the benefit of the measure if the measure increases the use of an item that will be regulated by a future building code or appliance efficiency standard.[4] The adjustment can be applied if there is either a specified standard that has not yet commenced, or a specified proposal.

The guidance provided for the regulation (Province of British Columbia 2014) explains that the BCUC can attribute a portion of the savings that will result from the standard to a program that includes the measure and helps transform the market for the measure. The BCUC can determine what share of savings from the standard will be attributed to the program and for what period.

This regulation is unique in that it seeks to account for the effect of programs on readying the market for standard adoption and advancing the effective date of standards. The intent of the regulation is to bolster the cost-effectiveness of a program, rather than to claim the energy savings within that program, (i.e., to attribute "benefits" but not attribute energy savings). The regulation and guidance do not provide any direction for how the BCUC should determine the amount of benefits to be attributed to the program.

Methodology

Cadmus reviewed policies and practices in 27 jurisdictions outside of British Columbia to understand how C&S savings are attributed to utility or PA efforts. Table 1 lists the two other provinces in Canada and numerous jurisdictions in the United States Cadmus examined.

4 BC's DSM regulation was enacted in 2008 and amended in 2011, 2014, and again in 2017. Section 4(1.4) has been unchanged since 2011.

Table 1. Reviewed Jurisdictions

Jurisdictions	
Canada	
Manitoba	Ontario
United States	
California	Colorado
Connecticut	District of Columbia
Hawaii	Illinois
Iowa	Massachusetts
Minnesota	Missouri
Nevada	New Hampshire
New Jersey	New York
Pacific Northwest (ID/MT/OR/WA)	Pennsylvania
Rhode Island	Texas (Austin)
Utah	Vermont
Arizona	

Three main sources of data were used to support this study:

- Publicly filed reports
- Communications with stakeholders in various regions
- Literature review of papers and presentations discussing PA involvement with C&S

Cadmus examined whether each jurisdiction has program activities related to codes, standards, or both. We then characterized each jurisdiction based on the type(s) of activity we observed: support for new C&S or compliance enhancement efforts. Lastly, we outlined whether savings attribution is determined in each jurisdiction and, if so, the process for determining attributable savings.

We have categorized the attribution process in each jurisdiction depending on how substantive and formal it is. Although the process in most jurisdictions fits a specific category well, we found a few processes that were combinations or hybrids of different processes, so were difficult to assign to a single category. Also, we found the process in several jurisdictions had not been fully defined yet. In both these cases, we decided which categorization fit best and explained our rationale.

This report builds on previous Cadmus attribution research. In 2014, Cadmus examined and summarized the attribution efforts of 14 jurisdictions across North America (Cadmus 2014). Comparisons to Cadmus' previous research are made throughout the document and many conclusions are based on notable changes and trends.

We have made every effort to be as comprehensive as possible, but the involvement of PAs in C&S activities is changing over time so any review is a snapshot of the situation at a point in time. In addition, entities other than PAs have primary responsibility for most activities associated with building codes and appliance standards so there is not much documentation of the role of PAs that are involved. However, Cadmus believes that the jurisdictions and PAs covered here capture the full range of energy savings and attribution approaches that exist.

The next section of this report presents the findings for building codes. The section after presents our findings for appliance standards. More PAs have programs that support building codes than appliance standards. Of 18 jurisdictions where PAs are involved in building energy codes, nine also support appliance standards.[5] In recent years, there has been a trend toward PAs supporting code compliance enhancement rather than building code adoption, and the number of PAs supporting standards activities has grown recently.

[5] For accounting purposes, this report treats the Pacific Northwest—Oregon, Washington, Idaho, and Montana—as a single jurisdiction because of the high degree of coordination and integration provided by the Northwest Energy Efficiency Alliance and other regional bodies.

Building Codes Policy Results by Jurisdiction

Summary of Findings

Table 2 provides a high-level overview of the role PAs play in building codes in several jurisdictions, including whether PAs support code adoption and support efforts to increase compliance with codes, and how savings are or are not attributed to PAs for their building code activities. We did not find any other jurisdictions that followed BC's DSM regulation approach of attributing benefits to DSM programs prior to the adoption of a code or standard that regulates a measure or measures included in the DSM program.

Table 2. Summary of Building Code Results

Jurisdiction	Status	Activity for Adopting Codes?	Activity for Compliance Enhancement?	Program Administrator Attribution Method
Formal Attribution Approach				
California	Program and attribution process in place more than 10 years	✓	✓	Use evidentiary record, expert panel; focused on code adoption only
Pacific Northwest	Attribution process in place 10 years	✓	✓	Use evidentiary record; attribution based on share of funding for regional market effects program; focused on code adoption only
Massachusetts	Attribution completed in 2018		✓	Use evidentiary record, expert panel; focused on compliance enhancement
Rhode Island	Attribution completed in 2017		✓	Use evidentiary record; focused on compliance enhancement
New York	Process established; attribution not yet completed	✓	✓	Use evidentiary record, expert panel; focused on compliance enhancement only
Arizona – Salt River Project	Attribution process in place several years and multiple analyses completed	✓	✓	Use evidentiary record, evaluate attribution percentage, not-to-exceed 50%; focused on code adoption
Illinois	Process established; attribution not yet completed		✓	Use evidentiary record, expert panel; focused on compliance enhancement
District of Columbia	Process not developed yet		✓	Considering California and others
Deemed Attribution Approach				
Arizona – Investor Owned Utilities	Program and attribution process authorized for eight years	✓	✓	Evaluate portion of maximum allowable attribution percentage
Texas (Austin)		✓	✓	Deemed savings are claimed

Jurisdiction	Status	Activity for Adopting Codes?	Activity for Compliance Enhancement?	Program Administrator Attribution Method
Pennsylvania	Attribution permitted in late 2018		✓	Evaluate portion of maximum allowable attribution percentage
Full Savings Without Determining Attribution				
Ontario				No support for codes; regional savings goal
Manitoba		✓		No attribution; claim full territory savings as a result of advocacy efforts
Attribution Permitted: No Approach Specified				
New Jersey	Attribution permitted in mid-2018		✓	No approach specified
Minnesota	Permitted since 2007		✓	No approach specified
No Attribution: Codes Savings Considered Non-Resource[a]				
Vermont			✓	No attribution; code program is non-resource
New Hampshire			✓	No attribution; code program is non-resource
Missouri			✓	No attribution; code program is non-resource
Iowa			✓	No attribution; code program is non-resource
Colorado			✓	
Utah			✓	No attribution; code program is non-resource
Hawaii		✓	✓	No attribution; code program is non-resource

[a] The term non-resource refers to programs that are not expected to result in direct savings but contribute to the acquisition of energy efficiency through education, outreach, training, or other general approaches.

Formal Attribution Approach

In 2014, Cadmus found that while many jurisdictions recognized energy savings arising from building energy codes, only two instituted a formal assessment of attribution—California and Massachusetts—and Massachusetts' process was in the pilot stage. More recently, three additional states have proposed or initiated formal attribution processes: Rhode Island, New York, and Illinois. Additionally, Cadmus determined the Pacific Northwest's attribution process was better categorized as a formal approach for this report. The following sections detail how each state is claiming or proposes to claim savings for their code adoption support or compliance enhancement programs.

California

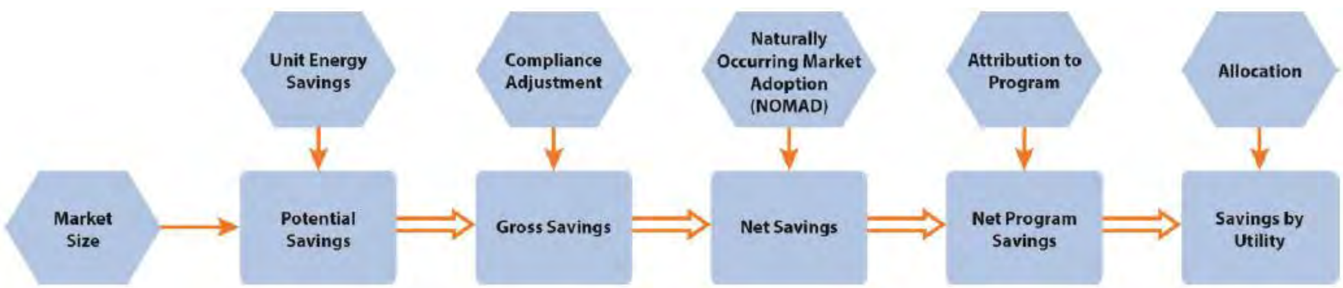
California investor-owned utilities' (IOUs') Codes and Standards program supports technical and market research of new technologies and practices, advocates for the adoption of more efficient regulations, and provides compliance enhancement support of California's Building Energy Standards (Title 24) and Appliance Standards (Title 20), as well as federal appliance and equipment standards implemented by the Department of Energy's Building Technologies Office. According to a recent report (California Public Utilities Commission [CPUC] 2018), "Savings from Codes and Standards are consistently the most cost-effective savings available to IOU efficiency programs, since these programs impact all new buildings constructed and appliances purchased in the state."

The California IOUs initiated their efforts to support codes and standards in the late 1990s and treated them as a non-resource program (that is, they claimed no savings from their efforts). For the 2006-2008 program cycle, the CPUC authorized IOUs to claim and receive credit toward their savings goals for C&S activities. Because this was the first time C&S savings were analyzed and accredited, the CPUC directed that the savings be discounted by 50%. For the 2010-2012 and 2013-2015 program cycles, IOUs received full evaluated savings credit for the program using the California Codes and Standards Advocacy Program Evaluation Protocol.

California Evaluation Protocol

The California Codes and Standards Advocacy Program Evaluation Protocol, illustrated in Figure 1, shows the steps and major factors used to identify program attributable net savings for efforts advocating for new C&S (Cadmus and DNV GL 2016).

Figure 1. Codes and Standards Advocacy Program Evaluation Protocol



Source: (Cadmus and DNV GL 2016)

The potential energy savings attributable to the C&S program is based on the estimated unit energy savings and the number of those units (building code measures or appliances) entering the market each year. To derive gross energy savings, evaluators apply a compliance adjustment to potential savings. Net savings result from adjusting the gross savings by the naturally occurring market adoption (NOMAD) of measures or appliances meeting the code or standard that would have occurred in the absence of the code or standard. Net program savings that are credited to the statewide C&S program are then determined by applying an attribution score; each of the four IOUs is then allocated net savings attributable to the program based on their share of the statewide energy market (for electricity or gas).

In California, the California Energy Commission has responsibility for adopting new codes or standards. The rationale for including the attribution step is that the statewide C&S program is designed to influence which C&S are adopted and at what level, so a portion of the credit for the C&S savings can be attributed to the utilities' efforts. For each technology or building practice, the evaluator must establish the percentage of savings resulting from program efforts. As there are no limits on the proportion of savings that are attributable to C&S initiatives, scores can range from 0% to 100%.

The process of determining attribution is formally done through an attribution panel consisting of independent C&S experts. The evaluator's process of determining attribution entails the following steps:

1. The evaluator collects information and compiles documentation on stakeholder activities from a range of sources, including rulemaking dockets, code change theory reports (written by the IOUs), and stakeholder interviews. [6]
2. A panel of independent C&S experts assesses the information compiled by the evaluator on the program's contributions to the adoption of each C&S based on a careful and systematic review of the evidence. Having independent experts evaluate program contributions lessens concerns about potential biases from having utility representatives directly involved in determining credit for their own efforts.
3. The evaluator researches and estimates the relative effort necessary to adopt a new code or standard based on three general factor areas required for adoption: (1) development of compliance determination and other special analytic methods, (2) development of technical information, and (3) stakeholder outreach and feasibility of code or standard. The evaluator then applies these relative measures of effort to the contribution made by the program in each area to produce a weighted attribution score for each C&S (Cadmus and DNV GL 2017).

To date, the IOUs have claimed and received energy savings credit for only advocating for adoption of building codes. However, they have engaged in an ongoing program to enhance code compliance for several years, so are likely to pursue getting credit for savings from this program as well. When that occurs, the current evaluation and attribution methodology will need to be modified as needed.

Since California's protocol has been in practice the longest, it is often referenced by other states and jurisdictions.

Code Compliance Savings from New Construction Program Spillover

The California IOUs have argued unofficially that their incentive programs for new buildings should receive some credit for savings from building codes because they "ready the market" for new codes. This claim was the only case we found in our research that relied on logic similar to that presented in the

[6] The California IOUs provided Code Change Theory Reports to evaluators, which provided the IOU perspective about the C&S team's contributions to rulemaking. This information from the reports is used in the determination of program credit for applicable standards and building codes.

BC DSM regulation. The CPUC has not accepted that position, however, because the IOUs are receiving savings credit directly from their statewide C&S program.

In an October 2007 Decision (D.07-10-032), though, the CPUC issued a directive to explore possible market effects of building programs on code compliance rates and the ability to credibly quantify and credit such nonparticipant spillover. When the decision was issued, the IOUs' residential new construction (RNC) programs encouraged high-performance building designs that exceeded the 2005 Title 24 energy-efficiency requirements by 15% or more, while also aiming to increase the adoption and installation of individual high-efficiency measures (KEMA 2010). Using market data and two Delphi panels, a consultant's study estimated that the IOUs' 2006-2008 RNC programs were responsible for approximately 23% of the gross electricity savings from achieving code compliance in non-program homes (Massachusetts Group and NMR Group, Inc. 2010). Although these savings could, in theory, be attributed to the RNC program, they would be accounted for in the C&S program evaluation and the CPUC has not authorized any crediting of the savings to the incentive program.

Pacific Northwest (Idaho, Montana, Oregon, and Washington)

The Northwest Energy Efficiency Alliance (NEEA), a regional nonprofit organization, manages the Pacific Northwest's market transformation efforts, which include work supporting building codes and appliance standards. From NEEA's website: "The long-term goal of NEEA's market transformation programs is often to lock in energy savings through progressively effective energy codes and standards. NEEA supports regional stakeholders in energy code development and adoption, training and implementation. Program staff serve as technical experts during U.S. Department of Energy rulemakings to encourage the adoption of federal appliance and equipment efficiency standards." NEEA has been supporting regional building codes since 1997 and, recently, has become more active in efforts to adopt national model energy codes. After the adoption of a code, NEEA provides technical support and training for regional compliance.

NEEA is classified as having a formal attribution approach as it has conducted studies to quantify attribution to NEEA's efforts in the past, though NEEA has not continued to update these analyses. As with some other jurisdictions, the approach in the region is a hybrid involving a mix of formal attribution, allocation, and integration of savings with the load forecast.

In 2008, Cadmus (formerly Quantec) developed and implemented a method for assessing attribution of energy code savings to NEEA's regional efforts to support code adoption and implementation. We did not find any information documenting a more recent assessment of attribution. The assessment used the following approach:

- Estimate regional energy savings from code adoption.
- Calculate net savings as a portion of total regional savings by subtracting the market baseline (typically estimated through independent evaluations) that would occur naturally without NEEA or programmatic intervention.
- Subtract savings claimed by sponsors' efficiency programs (to avoid double counting).

- Estimate attribution to NEEA's efforts by counting the number of times various entities are mentioned in response to open ended questions regarding organizations that influenced code adoption in each state.

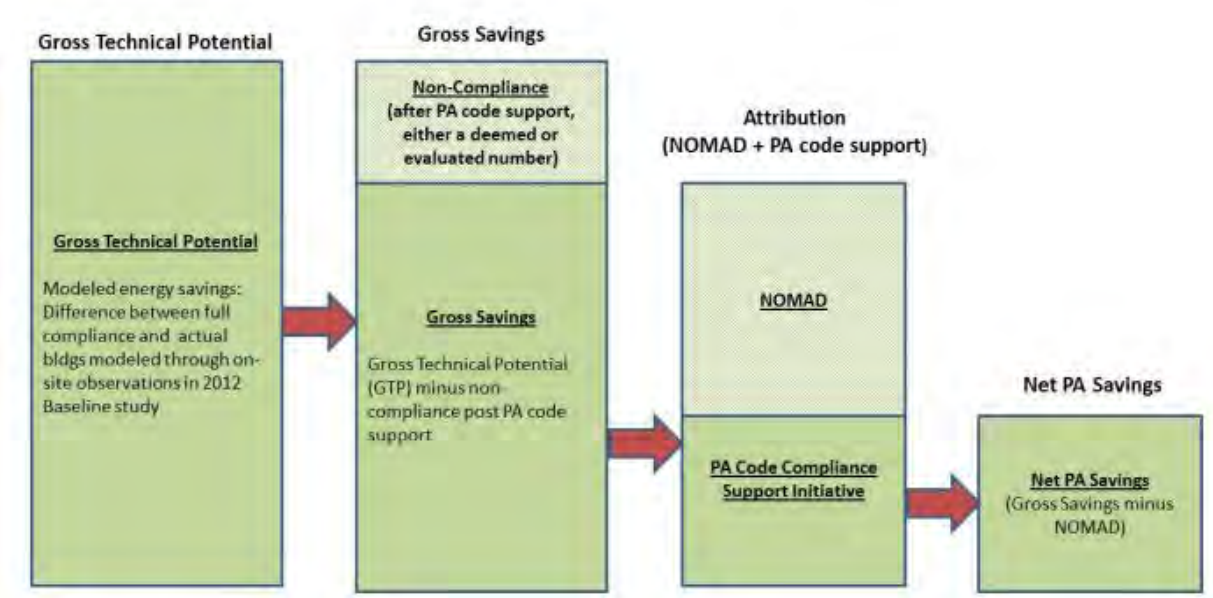
NEEA's energy savings are claimed by its funding partners (Bonneville Power Administration, public utilities, etc.) in proportion to the amount of funding provided to NEEA. This is a reasonable way to allocate savings among regional parties and similar to the approach agreed to by the California IOUs.

Utilities in the Pacific Northwest usually do not try to claim savings outside of NEEA efforts because of the increased level of scrutiny that would invite, and because of the additional documentation requirements such as providing sales data.

Massachusetts

Since 2014, the Massachusetts PAs have funded the Code Compliance Support Initiative (CCSI), a compliance enhancement effort aimed at educating code officials and building professionals on the residential and commercial building energy codes implemented throughout the Commonwealth of Massachusetts. The program initially ran as a pilot (through 2015) with no claimed savings (described later as a non-resource program). A preliminary savings methodology for evaluating the PAs' effort was developed by the PAs in 2015 and presented to the Massachusetts Department of Energy Resources. The methodology, as shown in Figure 2, calculated gross savings and net energy savings, or the portion attributable to the CCSI, after considering such factors as non-compliance and NOMAD (Massachusetts Program Administrators 2015).

Figure 2. Massachusetts PA Preliminary Net Savings Calculation Methodology



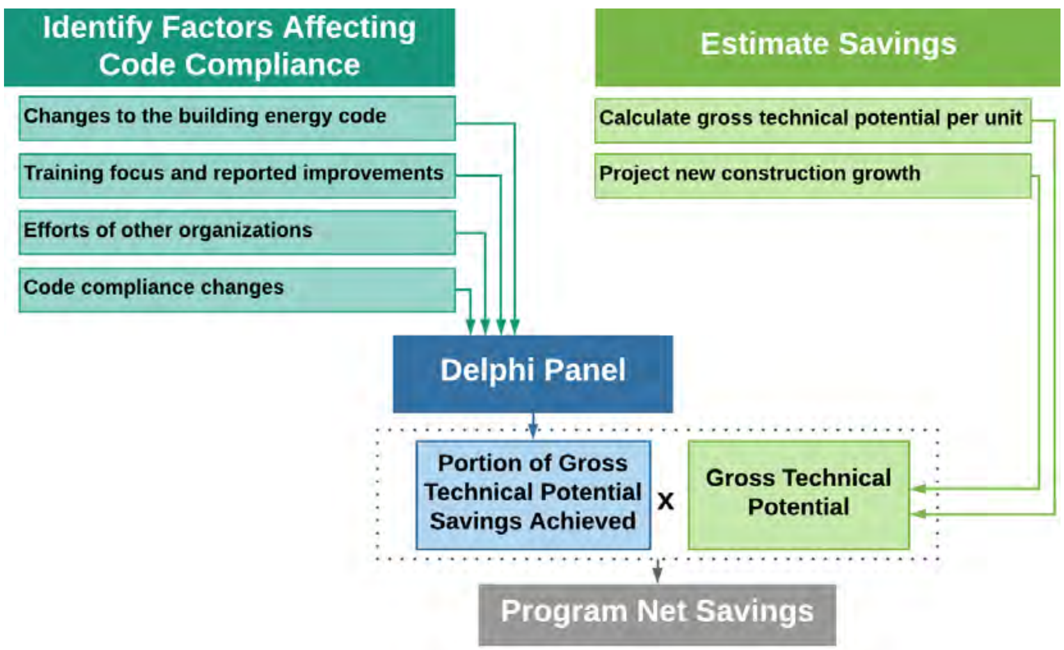
Source: (Massachusetts Program Administrators 2015)

In 2018, the Massachusetts PAs and the Energy Efficiency Advisory Council consultants contracted with the Massachusetts Cross-Cutting Research Area evaluation team to estimate prospective savings attributable to the PAs from the code compliance enhancement efforts of the CCSI. The evaluation teams used the net savings calculation presented to Massachusetts Department of Energy Resources as the starting point for the commercial and residential attribution assessments, as discussed in subsequent sections.

Commercial New Construction and CCSI Attribution Assessment

To develop an attribution score and project CCSI net savings for 2019-2021 for new commercial buildings, the Massachusetts Cross-Cutting Research Area evaluation team (NMR and Cadmus) used a Delphi panel approach modeled after the California protocol. For this evaluation, a panel of code experts reviewed documentation on CCSI activities and provided estimates of code compliance over the period under two scenarios: (1) with CCSI activities continuing at a similar level to previous efforts and (2) without implementation of the CCSI. Figure 3 illustrates the process used by evaluators to assess attribution and calculate estimated savings from the CCSI.

Figure 3. Massachusetts Attribution Study Approach



Source: (NMR and Cadmus 2018)

The first step in the process was to identify and provide to the expert panel the factors affecting code compliance. Documentation supplied to the panel included the following:

- Background information on the initiative
- Baseline and follow-up compliance study results
- Key changes to energy code requirements
- Reported impacts of training and technical assistance

- Gross technical potential modeling results for compliance enhancement
- Compliance enhancement efforts of other organizations throughout the state

From this documentation, the Delphi panel estimated compliance under two scenarios: (1) with the CCSI continuing code enhancement activities in the future at a similar level to historical efforts and (2) with the CCSI never having been implemented. The Delphi panel deliberated compliance in two rounds. In the first round, panelists provided estimates and their rationale for compliance under the two scenarios. In the second round, the panelists reviewed a compilation of their peers' first-round estimates and revised their estimates, if desired.

The team then estimated the gross technical potential using the baseline technical potential and projected commercial building new construction. Finally, to estimate program net savings, we multiplied the CCSI attribution as determined by the Delphi panel by gross technical potential, as shown in the following equation:

$$Program\ Net\ Savings_{year} = Program\ Attribution_{year}\ x\ Gross\ Technical\ Potential_{year}$$

The evaluation team provided the Massachusetts PAs and the Energy Efficiency Advisory Council with estimated program net savings for 2019-2021 program period (Cadmus and NMR Group, Inc. 2018).

Residential New Construction and CCSI Attribution Assessment

Using a methodology similar to the commercial attribution assessment, NMR forecasted net-to-gross (NTG) ratios for the low-rise RNC program and the residential portion of the CCSI for the 2019-2021 program period. [7] The assessment covered both programs, which target the single-family residential new construction market, together to avoid double counting savings and to ensure all savings attributable to the PAs were documented (NMR Group, Inc. 2014).

The evaluation team calculated a retrospective NTG ratio for the 2015 program year and prospective NTG estimates for 2019-2021. To estimate retrospective NTG ratios, the team conducted the following activities:

- A Delphi panel of codes experts estimated measure-level efficiencies as if the RNC and CCSI programs never existed (referred to as the counterfactual scenario) in two rounds.
- The energy consumption of program and non-program homes was modeled as constructed (referred to as the as-built scenario) and under the counterfactual scenario determined by the Delphi panel.
- Evaluator estimated retrospective net savings and NTG estimates using analysis of the as-built and counterfactual energy consumption.

To develop prospective NTG estimates, the team then produced and presented to the Delphi panel an internal forecast of the impact of the programs in 2019-2021. The Delphi panelists, in a third-round,

[7] The methodology was consistent with NMR's 2014 Residential New Construction Net Impacts Study.

suggested changes to the forecasted estimates, which the team used to adjust retrospective findings and develop NTG ratios for 2019-2021 (NMR Group, Inc. 2018).

Rhode Island

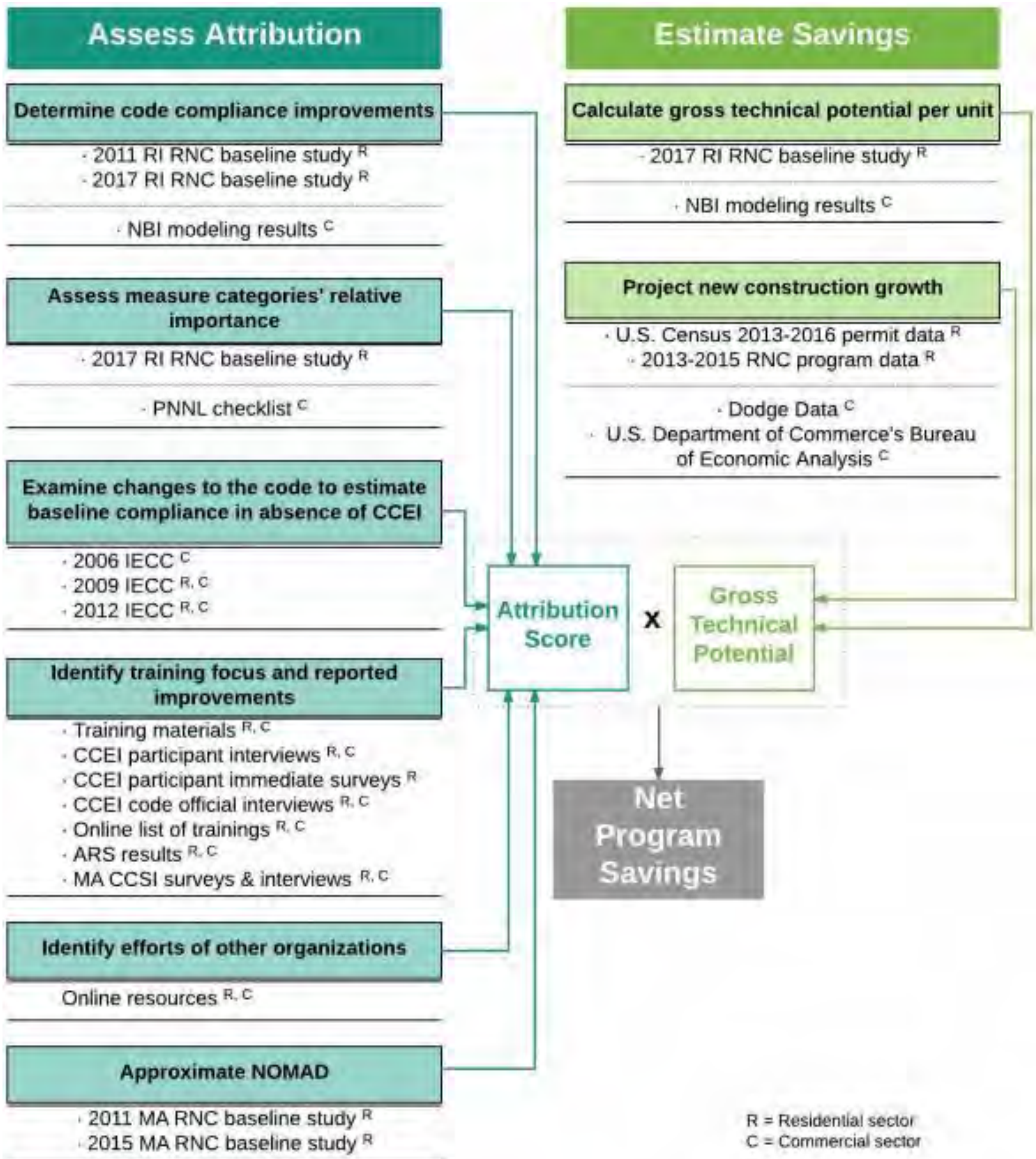
National Grid, the only IOU in Rhode Island, implements a code enhancement program like Massachusetts' CCSI; the Code Compliance Enhancement Initiative (CCEI) provides trainings, circuit rider[8] technical assistance, third-party inspection support, and other code compliance tools and resources covering both the residential and commercial energy codes. The CCEI also focuses on stakeholder engagement activities, such as attending local code official meetings and industry or trade group events, and program implementers visit each building department throughout the state. These CCEI activities, which began in 2013, have been National Grid's initial short-term focus and are a part of National Grid's larger C&S initiative, which encompasses four components: code compliance through CCEI; appliance standards development and advocacy; stretch code development; and base code advocacy.

In December 2012, National Grid, with the support of the Energy Efficiency Resource Management Council, developed a model for attribution that was approved by the Rhode Island Public Utilities Commission. In 2017, NMR estimated the savings in the residential and commercial new construction markets attributable to the CCEI in the 2018-2020 period due to its code compliance enhancement efforts.

Figure 4 illustrates the iterative attribution approach used by the evaluators. This approach is like the approaches used in California and Massachusetts in that a broad range of resources, including baseline compliance studies, reported impacts of training, and NOMAD estimates, were used to determine an attribution score. However, unlike California and Massachusetts, the attribution score was determined solely by the evaluation team rather than a Delphi panel (NMR Group, Inc. 2017).

8 An energy code circuit rider provides statewide energy code training, technical support, and code interpretations to design and building professionals, permitting departments, and code officials.

Figure 4. Rhode Island Attribution Assessment Approach



Source: (NMR Group, Inc. 2017)

New York

The Energy Conservation Construction Code of New York State (ECCCNYS) is updated regularly by the State Fire Prevention and Building Code Council. The New York State Department of State Division of Building Standards and Codes serves as secretariat to the Building Code Council; the Building Standards and Codes administers the energy code, provides training and education, and supports local code enforcement (New York Department of State 2018). The New York State Energy Research Development Authority (NYSERDA) also serves as the program administrator for code compliance and enforcement programs, including the Advanced Energy Codes and Standards Program and the Clean Energy Fund.

Advanced Energy Codes and Standards Program

In 1996, the New York State Public Service Commission established a System Benefits Charge (SBC) to fund initiatives that serve all energy consumers throughout New York State. The SBC was renewed several times over the last two decades, with the most recent extension ending in December 2016. The SBC program was primarily administered by NYSERDA, and the 2012-2016 order funded a Technology and Market Development Portfolio comprising nine initiatives, including the Advanced Energy Codes and Standards Program (New York State Energy Research Development Authority 2013).

The Advanced Energy Codes and Standards Program aimed to reduce energy use by increasing compliance with the ECCCNYS; developing a voluntary stretch code for local adoption; and contributing to the development of appliance and equipment standards, specifically those not covered by federal standards. Through the energy codes component of the program, NYSERDA coordinated code enhancement services and resources for code officials, design professionals, and third-party energy professionals; these included training opportunities, technical assistance, plan review and inspection support, and code enforcement and implementation tools.

To date, NYSERDA has not claimed savings from its code activities. However, two process evaluations on NYSERDA's energy code training efforts have been completed and an impact evaluation to attribute energy savings to the program's code enhancement activities is underway (Industrial Economics, Incorporated 2016 and 2017). The impact evaluation consists of two separate Delphi panels. The first Delphi panel,[9] completed in 2015, established an energy code compliance baseline and the second, expected to be completed in 2018, will evaluate the program's effectiveness and estimate the change in compliance between the two points in time (ERS and Industrial Economics, Incorporated 2016). The Delphi panel will be asked to estimate the change in compliance and how much of the change can be attributed to NYSERDA's efforts, natural market changes, and technology progress. This information will feed into a model that considers the construction volume and estimated energy savings due to code changes to estimate the energy savings attributable to NYSERDA's activities.

Clean Energy Fund

Currently, NYSERDA has 25 Clean Energy Fund Investment plans intended to reshape the energy efficiency landscape in New York by providing clean energy and energy innovation programs to a wide range of consumers and help meet the state's commitment of 50% renewable energy by 2030 (NYSERDA 2016). The Codes Chapter of the Clean Energy Fund, issued November 2017, is designed to support compliance with and enforcement of the ECCCNYS, advance the development of stretch energy codes, and provide technical assistance and other services to support the enactment of state and local energy codes. Code to Zero, the first initiative of the Codes Chapter, has three main goals:

- Code compliance reaches 90% throughout New York
- 20% of jurisdictions adopt a stretch code

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9 The process for the first Delphi panel consisted of three rounds of one-on-one interviews.

- Jurisdictions that adopt alternative code enforcement structures or receive training and supplemental services report improved enforcement of the energy code (NYSERDA 2017)

For each goal, NYSERDA has established performance metrics that will be analyzed over the length of the initiative, including the number of training attendees and percentage of market complying with the energy code. Although the evaluation plan has not been finalized, NYSERDA anticipates using a Delphi panel process to establish a compliance baseline, estimate NOMAD, and measure the impact of the initiative over time. Additionally, it is expected that the evaluation team will conduct ongoing interviews with representative jurisdictions to compare to the Delphi panelists' responses. NYSERDA will use these evaluations to quantify long-term, indirect energy savings impacts attributable to the Code to Zero initiative.

Arizona—Salt River Project

Salt River Project (SRP), a community-based not-for-profit electric provider in Phoenix, claims savings for supporting C&S adoption and implementation activities. As described later, the Arizona Corporation Commission (ACC) adopted rules that allow IOUs to claim savings from codes and standards, but as a political subdivision of the State of Arizona, SRP is not regulated by the ACC (Cadmus September 9, 2018). SRP's board, however, decided to allow the utility to claim up to 50% of the savings from a code or standard if it demonstrates influence over the adoption of the new code or standard (Cadmus 2012).

SRP's Building Energy Code Initiative offers education, training, and support to city councils and the state legislature to influence the adoption and enforcement of building energy codes within the cities and code jurisdictions SRP serves (SRP 2018). Aside from working with local code officials to drive adoption and consistent enforcement practices across the Phoenix metropolitan area, SRP leverages its governmental status and voting rights to influence the development of new building energy codes at the national level to better serve Arizona and the Southwest region.

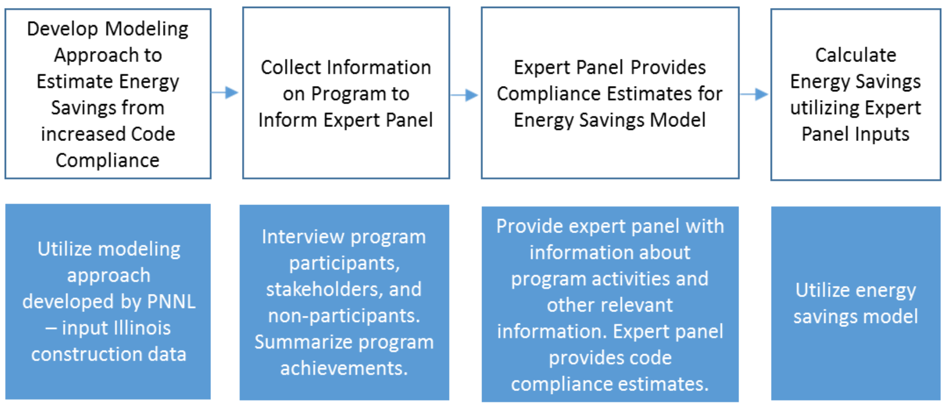
SRP has worked with Cadmus and other third-party evaluators to document the initiative's influence and attribute the appropriate amount of energy savings from building codes to its portfolio. SRP modeled its attribution approach after California and Massachusetts, with modifications to make it more applicable to home rule states. Evaluation activities have included interviews with stakeholders and jurisdictions, and assessments of materials developed by SRP to determine the influence SRP has had on the process. Cadmus has used building simulation data to estimate code savings and implemented an innovative billing data analysis to estimate residential code savings (Bonesteel 2017).

Illinois

For several years, the Illinois Department of Commerce and Economic Opportunity (DCEO) administered the Building Energy Codes Education and Technical Assistance Program, a comprehensive program aimed at supporting the adoption, implementation, compliance, and enforcement of the Illinois Energy Conservation Code. The program effectively ended in 2016 due to a lengthy impasse over the state budget, with energy efficiency program administration responsibilities shifting to the utilities.

At the request of DCEO, Cadmus, as a subcontractor to ADM Associates, evaluated the impact of the program on energy savings for the 2014, 2015, and 2016 calendar years and for program years 7, 8, and 9; each program year ran from June 1 to May 31 (Cadmus 2017). Cadmus' formal approach, summarized in Figure 5, utilized a panel of experts to estimate the difference in the level of compliance due to the program. Cadmus calculated the energy savings estimates for both the residential and commercial sectors using input from the expert panelists and Pacific Northwest National Laboratory's energy consumption models.

Figure 5. DCEO Energy Codes Education and Technical Assistance Analysis Approach



Illinois' Future Energy Jobs Act (FEJA) became effective in June 2017 (MEEA August 2018), requiring significant energy savings by the state's electric utilities.[10] To meet the savings goals, FEJA requires utilities to include proposals for C&S programs, as shown below (State of Illinois Public Act 099-0906 2016*)*.

Excerpt from FEJA:

> *In submitting proposed energy efficiency and demand-response plans and funding levels to meet the savings goals adopted by this Act the utility shall:*
>
> 1. *Demonstrate that its proposed energy efficiency and demand-response measures will achieve the requirements that are identified in subsections (b) and (c) of this Section, as modified by subsections (d) and (e).*
> 2. ***Present specific proposals to implement new building and appliance standards that have been placed into effect. (****Note: emphasis added by Cadmus).*

[10] The bill, passed in December 2016, amended the Public Utilities Act and the Illinois Power Agency Act. It requires Ameren Illinois to attain 16% and Commonwealth Edison Company to attain 21.5% cumulative annual persisting savings by 2030. Gas utility targets, as determined by 2009 amendments to the Illinois Power Agency Act, were unaffected.

Additionally, utility procurement plans must include an analysis of "the impact of energy efficiency building codes or appliance standards, both current and projected," along with opportunities to expand the programs.

In response to savings and C&S program requirements, Illinois gas and electric utilities have joined together for a potential statewide code compliance enhancement program. The utilities are currently involved in the Illinois Energy Codes Compliance Collaborative and are funding the Midwest Energy Efficiency Alliance (MEEA) and Cadmus to complete pre-program residential and commercial field studies; the studies will establish a compliance baseline and identify opportunities for improved compliance. The utilities will use results from the field studies to design and implement an Integrated Compliance Support Program, a suite of programs targeted at improving the compliance issues observed in the field. Savings from the programs will be verified through post-program studies and used to meet the utilities' savings targets, but the specific attribution analysis method has not been defined yet (MEEA September 2018).

District of Columbia

The District of Columbia Department of Energy and Environment (DOEE) oversees the DC Sustainable Energy Utility (DCSEU). Created as part of the Clean and Affordable Energy Act of 2008, DCSEU implements energy efficiency and renewable energy programs in the DC area (DOEE 2008). "The DCSEU operates under a performance-based contract with DOEE, with input and recommendations from the SEU Advisory Board, and oversight from the Council of the District of Columbia" (DOEE October 2018).

In a 2017 presentation developed by the DCSEU Advisory Board, savings attribution was included as a new strategy for efficiency savings. Per the presented material, attribution "accounts for the numerous ancillary service offerings the DCSEU offers to customers in addition to incentives" and it is noted that attribution was recommended in the 2016 draft of DC's energy and climate action plan, Clean Energy DC (DCSEU Advisory Board 2017).

Clean Energy DC was finalized in August 2018. The plan recommends that DCSEU invest in compliance enhancement efforts and receive credit for associated savings:

> *The DCSEU should assist DOEE, DCRA [Department of Consumer and Regulatory Affairs], the Green Building Advisory Council and the Construction Code Coordinating Board to develop and implement building-code improvements. The DCSEU should also design outreach and incentive programs for building owners, designers, and contractors with an eye to laying the foundation for future building code improvements. To incentivize such investments, the DCSEU should be credited for a portion of any energy savings attributable to the adoption of energy-saving building code improvements, as is the case in Arizona utilities. To maximize the energy savings realized from building code improvements, the DCSEU should invest resources in training, outreach, technical assistance, design assistance, marketing, explanatory materials, and other efforts to increase compliance with building codes. As codes become more ambitious, the DCSEU should receive credit for bringing poor performing buildings up to code. As the District has little history of crediting a demand-side management administrator for code-related energy savings …*

> *this would need to be resolved through an evaluation, measurement, and verification review and the subsequent development of appropriate guidelines.*

The plan also notes: “other jurisdictions, such as California, also provide utilities attribution for energy code adoption, but the Arizona model is most appropriate for a small jurisdiction like the District (DOEE August 2018).”

Staff at the Institute for Market Transformation (IMT), DCSEU’s subcontractor for code compliance trainings, and the DCRA, the department that supports code compliance and enforcement activities, indicated that they are actively working on an appropriate attribution approach. Per our correspondence with IMT staff: "Attribution is indeed being considered in association with the DC Sustainable Energy Utility’s work on building code development and implementation. These plans are still at a formative stage and will require further development, then extensive review before approval. Therefore, it’s premature to present details” (Cadmus October 3, 2018).

DCRA receives funding for code enhancement, as it is available, from DCSEU and is interested in helping DCSEU achieve its savings target through savings related to these activities. According to correspondence with DCRA staff, the department has proposed a baseline study that follows a building project from plan review to inspection to certificate of occupancy, and notes compliance issues throughout the process. Programs designed specifically to address the issues in compliance will then be proposed, with savings associated to the programs attributed to DCSEU. DCRA staff noted, “the traditional utility program has to transition to a world where the energy code is the law and support those laws through compliance support” (Cadmus October 2, 2018). Attribution details are still being developed.

Deemed Attribution Approach

Through our research, we identified three jurisdictions —Arizona (investor owned utilities), Austin, Texas, and Pennsylvania—that use a deemed approach to estimate energy savings attributed to PA energy code programs (that is, the deemed savings specify what portion of the savings are attributable to the PAs). The following sections detail how each state or jurisdiction is claiming savings for their code adoption support or compliance enhancement programs.

Arizona—Investor Owned Utilities

In 2010, the ACC adopted rules (Docket No. OOOOOC-09-0427) that require IOUs and rural electric cooperatives to achieve annual energy savings of at least 22% by 2020 (Southwest Energy Efficiency Alliance 2016). As a result, the regulated electric utilities, Arizona Public Service (APS) and Tucson Electric Power Company (TEP), have developed energy efficiency programs from which they can claim savings. The ACC allows the regulated utilities to claim electricity savings from building codes and gas savings from both building codes and appliance standards. The regulations do not establish an attribution process that is purely formal or purely deemed. The rules state that utilities can claim up to one-third of the savings generated by the codes or standards, but they must be quantified through a measurement and evaluation study conducted by the utility (ACC 2018).

TEP’s 2018 Energy Implementation Plan and APS’ Amended 2018 Demand Side Management Implementation Plan both include a codes and standards component. The objectives of TEP’s Energy Codes and Standards Enhancement Program, approved by the ACC most recently in Decision No. 75450, are to improve compliance with current energy codes and standards and support the adoption of newer codes and standards (TEP 2017). TEP claims savings from its codes and standards program but has not allocated budget to conduct an evaluation of the program. APS’ DSM plan includes the Building Codes and Appliance Standards Initiative, which offers compliance enhancement support to code officials, building professionals, and other market actors. APS claims significant electricity savings from the initiative (APS 2017), which are reviewed and verified annually as part of APS’ Measurement, Evaluation, and Research Reports. Per an interview with a consultant working on APS’ attribution, savings are estimated using publicly available sales data, field research within the APS territory, and market baselines (Cadmus October 9, 2018).

The 2017 APS Codes and Standards Report states that the savings “*reflect increased adoption of federal, state, and jurisdictional codes and standards (C&S) that are directly influenced by APS' portfolio of demand-side management (DSM) programs. This increased adoption results in more efficient baselines that, in addition to driving greater savings for C&S programs, reduce the savings potential for measures currently incentivized by APS' DSM programs. Therefore, each year APS adjusts its savings accordingly to reflect these baseline changes, which drives APS to pursue new program opportunities focused on the latest, most efficient technologies”* (Navigant 2018).

Texas (Austin)

The Austin City Council adopted the Austin Climate Protection Plan in 2007. The resolution includes goals for energy codes, including a goal in the 2012 update to the resolution to “implement the most energy efficient building codes in the nation” (Austin Energy 2012). Austin Energy, a publicly owned electric utility in Texas, administers many energy efficiency programs in support of the Climate Protection Plan, including the Austin Energy Green Building (AEGB) program. The program has been providing support to the design and construction communities to reduce building energy use and meet the climate protection goals of the city since 1990. AEGB oversees the City of Austin’s energy code; every three years, the program amends the code to reflect innovation in construction materials and practice, as well as any policy changes (Austin Energy Roadmap).

Austin Energy reports significant savings from the AEGB, with the greatest share due to code efforts (Austin Energy 2018). Cadmus did not find documentation indicating that an attribution analysis of code savings was conducted for this publicly owned utility. Instead, per email correspondence with Austin Energy’s Evaluation and Development Group, deemed savings factors based on energy models of various prototypical buildings are applied to building permits. The deemed savings factors represent the kW and kWh savings of the energy code to which the building is permitted over the baseline energy code in effect in 2007 (2001 International Energy Conservation Code [IECC] and by reference, ASHRAE 90.1-2001) (Cadmus September 21, 2018). A similar approach was proposed to evaluate AEGB’s Multifamily Rating Program, but Cadmus could not locate documentation of this effort (Reed 2014).

Pennsylvania

Pennsylvania is the most recent state to permit PAs to claim savings resulting from energy code programs. Per the General Assembly of Pennsylvania, Senate Bill No. 1235, September 2018 amendment to Title 66 (Public Utilities) of the Pennsylvania Consolidated Statutes, Pennsylvania utilities may claim up to one-third of the energy savings resulting from their involvement in building energy codes. The statutory language (shown below) is very similar to that in the regulation promulgated by the Arizona ACC:

Excerpt from Senate Bill No. 1236:

> *(3) The term includes up to one third of the energy savings and reductions resulting from energy efficiency building codes, provide that:*
>
> > *(i) The electric distribution utility played a direct role in achieving the savings and reductions through program implementation.*
> >
> > *(ii) The savings and reductions are quantified and reported throughout an independent measurement and evaluation study.*
> >
> > *(iii) The savings and reductions are commensurate with the direct role that the affected utility played to achieve the savings and reductions.*

Senate Bill No. 1236 ensures savings from code efforts can be applied to the energy reduction goals of Pennsylvania's seven major electric distribution companies, as required by Act 129 of 2008 (The General Assembly of Pennsylvania, House Bill No. 2200).

We did not find any details yet on whether the savings would be counted for code adoption or compliance enhancement efforts, or both. Also, there is no information available yet on whether attribution would be assessed, or utilities would just be able to claim one-third of resulting energy savings without having to quantify attribution.

Full Savings without Determining Attribution

In Ontario and Manitoba, code and standard savings are counted in a PA portfolio or regional savings model, without consideration of attribution. For perspective, this is the approach that BC Hydro takes, with the savings estimates subsequently used to develop a net load forecast.

Ontario

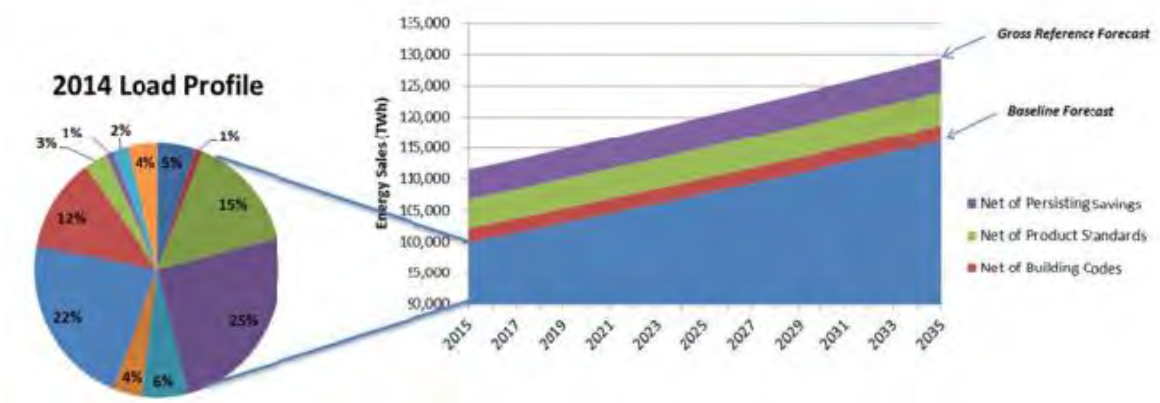
In 2015, Ontario Power Authority merged with the Independent Electricity System Operator (IESO), which oversees Ontario's local distribution companies (LDCs) and electricity market (IESO Power Authority Amalgamate 2018). IESO supports the LDC's conservation programs and aids with meeting the required savings targets outlined in the Conservation First Framework (IESO Conservation Delivery Tools 2018).

Savings are not estimated for C&S programmatic efforts claimed as contributing to each LDC's Conservation First Framework targets. They are addressed by subtracting forecast codes and standards savings from top-line gross load forecasts to develop a reference forecast for each LDC, with the result being a lower target. This process is explained in IESO's *2016 Achievable Potential Study: Short Term Analysis* report (Nexant 2016):

> *Subtract codes and standards and persisting savings from gross forecast: Nexant worked with IESO's staff to obtain the respective energy savings through the long term study horizon anticipated by end use due to the adoption of more stringent building codes (e.g. HVAC and lighting) and the adoption of more efficient product standards (e.g. appliances). Data provided by IESO summarized the persistent savings by measure from 2015, and Nexant allocated the appropriate persistent savings by LDC, by sector, and by end use and subtracted the savings from the gross reference forecast. These codes and standards, and persistent savings were subtracted from the top-line gross reference forecast to establish the baseline forecast.*

Figure 6 illustrates how each LDC's baseline load forecast was determined with consideration for codes and standards; the baselines reflect codes and standards savings regardless of an LDC's energy code efforts. IESO documents do not provide any assessment of possible LDC involvement in building code adoption or compliance enhancement.

Figure 6. IESO Illustration of Baseline Load Forecast Development by LDC



Source: (Nexant 2016)

Manitoba

Manitoba Hydro is the primary electric and gas utility in Manitoba, Canada. Its *2014-2017 Power Smart Plan* indicates that DSM targets include savings from C&S, which are considered separate from electric and natural gas DSM programs (Manitoba Hydro 2015). Per Manitoba Hydro's DSM plan for the 2016/17 fiscal year, "Manitoba Hydro's overall DSM strategy involves taking a broad approach to capturing energy efficiency opportunities: education to build awareness and understanding, creating foundations through the support of standards, motivating customers with the aid of financial tools, and entrenching energy savings through the support of federal and provincial codes and regulations" (Manitoba Hydro 2016).

The *Power Smart Plan* acknowledges: "A code or a regulation ensures permanent market transformation for the specific energy efficiency opportunity since a potential always exists that the market could revert back to the non-efficient option once Power Smart has reduced or eliminated its program support."

Manitoba Hydro's code activities include market intervention strategies, such as being an "aggressive and active participant" on provincial and national energy efficiency codes and standards committees. "Manitoba Hydro is heavily engaged in both Federal level and Provincial level committees that work to establish ongoing updates to minimum energy performance standards for technologies and to determine the appropriateness of their adoption into a code or a regulation."

The national commitment to update the 1997 National Energy Code for Buildings (NECB) was initiated in Manitoba by the Energy Code Advisory Committee which was led by Manitoba Hydro. Manitoba Hydro also chaired the national Building Energy Code Collaborative, which was formed in response to the recommendations provided by the Energy Code Advisory Committee. Manitoba was instrumental in getting jurisdictions across Canada to undertake the work to update the 1997 NECB. The Province still moved forward with its own energy strategy and, in January 2011, the energy efficiency amendments developed for the Manitoba building code were approved by the Building Standards Board of Manitoba and the Minister of Labour. Manitoba Hydro Power Smart staff contributed to the process of adopting specific amendments for Manitoba and staff continues to contribute to the national process for the development of the 2015 edition of the NECB.

Manitoba Hydro's influence on codes and standards is shown in the following example from the *2014-2017 Power Smart Plan:*

> *Effective December 1st, 2010, Manitoba implemented changes to the building and plumbing codes that increased energy and water efficiencies. These changes were the result of extensive consultations by the Office of the Fire Commissioner involving new homebuilders, contractors and technical experts. The new efficiencies incorporated into new construction and homes undergoing extensive renovations included:*
>
> - *specifying minimum energy-efficiency requirements for windows,*
> - *eliminating the pilot light in gas fireplaces,*
> - *increasing the required level of attic insulation to R50,*
> - *requiring a minimum 94 per cent fuel-efficiency rating for furnaces,*
> - *specifying a mid-efficient heat-recovery ventilator, and*
> - *introducing energy-modeling software that will allow builders to model alternatives to the code requirements.*
> - *Requiring a maximum flow rate for primary showerheads to 1.75 GPM*
>
> *Through its close working relations with key industry stakeholders and the Power Smart New Home Program offering, Manitoba Hydro succeeded in advancing these changes to the Manitoba Building code. In fact, a majority of the technologies adopted by the Manitoba Building Code for the December 1, 2010 update were part of the aforementioned Power Smart Gold Home standard requirements. Without the program*

> *providing information, education, training, and incentives for these technologies and building practices, the industry would have been less likely to adopt these technologies and transform the market. The program created demand for these technologies, provided builders an opportunity to gain experience using them, and provided trades and contractors training opportunities to advance their expertise and knowledge of the technologies.*

Manitoba Hydro prepares an annual forecast of the expected influence of currently implemented regulated and nonregulated codes and standards; the forecast is used to adjust Manitoba Hydro's system load forecast. The full savings are counted toward the utility's savings goals without any estimation of attribution.

Attribution Permitted: No Approach Specified

Utility interest in claiming C&S energy savings is increasing and the initial framework necessary to claim savings is emerging in various jurisdictions. Cadmus identified two states that permit attribution, but that have not yet defined exactly how savings are credited.

New Jersey

In May 2018, New Jersey's Act Concerning Clean Energy (Clean Energy Act), Bill A-3723, was signed into law. The act, effective immediately, requires utilities to establish energy efficiency and peak demand reduction programs to be approved by the Board of Public Utilities (BPU). Load reduction targets vary by gas and electric public utilities (The Senate and General Assembly of the State of New Jersey 2018). Gas utilities will be required to achieve, within five years of program implementation, reductions of at least 0.75% of the average annual usage in the prior three years; electric utilities must achieve reductions of at least 2% under the same scenario (Day Pitney Alert 2018).

Within one year of the Clean Energy Act, the BPU must adopt performance indicators for each public gas and electric utility to "establish reasonably achievable targets for energy usage reductions and peak demand reductions and take into account the public utility's energy efficiency measures and other non-utility energy efficiency measures including measures to support the development and implementation of building code changes, appliance efficiency standards, the Clean Energy program, any other State-sponsored energy efficiency or peak reduction programs, and public utility energy efficiency programs that exist on the date of enactment of P.L.2018, c.17 (C.48:3-87.8 et al.)."

To achieve the targets established by the board, the Clean Energy Act permits utilities to "apply all energy savings attributable to programs available to its customers, including demand side management programs, other measures implemented by the public utility, non-utility programs, including those available under energy efficiency programs in existence on the date of enactment of P.L.2018, c.17 (C.48:3-87.8 et al.), building codes, and other efficiency standards in effect, to achieve the targets established in this section."

It is unclear at this time how savings will be attributed to codes and standards programs.

Currently, the BPU is also administering New Jersey's Clean Energy Program, a statewide program that offers energy efficiency programs, incentives, and services. The BPU does not count energy code savings in its savings reporting except for the incremental amount above current code, determined by the Protocols to Measure Resource Savings (State of New Jersey Board of Public Utilities 2018). According to correspondence with a senior policy advisor from BPU, the gas and electric utilities with programs supplementary to the New Jersey's Clean Energy Program account for energy savings in the same manner (Cadmus September 27, 2018).

Minnesota

In 2007, Minnesota passed the Next Generation Energy Act with a goal of reducing emissions by 80 percent by 2050. The policy allows utilities to claim savings credit for building codes and appliance standards toward the annual energy savings target (State of Minnesota 2017).

Excerpt from the Next Generation Energy Act of 2007:

> ***Sec. 4. [216B.2401] ENERGY CONSERVATION POLICY GOAL.***
>
> *It is the energy policy of the state of Minnesota to achieve annual energy savings equal to 1.5 percent of annual retail energy sales of electricity and natural gas directly through energy conservation improvement programs and rate design, and indirectly through energy codes and appliance standards, programs designed to transform the market or change consumer behavior, energy savings resulting from efficiency improvements to the utility infrastructure and system, and other efforts to promote energy efficiency and energy conservation.*

Minnesota's electricity and natural gas utilities administer the Conservation Improvement Program ([CIP]; Minnesota Department of Commerce 2018). Historically, CIP program policies did not allow programs to claim savings for code efforts; however, "numerous developments within the last several years have suggested that CIP-funded programs that increase code compliance could be given credit for energy savings in Minnesota" (Center for Energy and Environment 2018).

In March 2018, the Center for Energy and Environment (CEE) provided the Minnesota Department of Commerce, Division of Energy Resources (DER) with a summary of opportunities for CIP-funded code compliance programs and recommendations for an approach to estimating savings for code efforts.

CEE recommended that energy savings for code programs be based on a third-party impact evaluation but did not provide a detailed approach. However, CEE proposed guidelines to "meet the need for utilities to have confidence in the ability to claim savings while also providing a degree of rigor in the savings quantification process." These guidelines include the following:

- "Utilities should be encouraged to file for cost-effective code-compliance programs, and to work collaboratively with the DER and other utilities to come up with an appropriate evaluation plan in their filing.

- During program implementation, the evaluation should be carried out by a third party. Evaluation contractors could either be directly contracted by DER with program funds provided by the utility, or at least have the evaluation firm credentials approved by DER.
- Utilities should be encouraged to work together to jointly implement programs that would be evaluated together as well. In addition to having the benefit of being able to be more easily evaluated, it would also be a more efficient use of ratepayer dollars.
- During program development, each individual utility (or ideally, a group of utilities) is responsible for contracting directly with a DER approved evaluation firm to develop the evaluation plan, in a form that will provide for competitive bidding of the implementation evaluation. The integration of savings evaluation planning into the program development process is meant to provide utilities with a degree of confidence that a proposed program will be able to count an appropriate level of savings.
- DER approval of evaluation firms should be based on minimum standards for experience with program evaluations and with energy code compliance programs, and be a third party (i.e. a firm cannot evaluate a program it is delivering). Certain, reasonable limits on claiming savings could also be established by DER through the TRM [Technical Resource Manual] (e.g. a limit of 30% of savings compared to the previous code for general education only programs). As precedents for specific types of compliance programs are established through individual program approvals, the TRM can be updated with guidance for future, similar programs."

According to correspondence with a MEEA policy manager, the state has not yet acted on CEE's recommendations.

No Savings: Codes Considered Non-Resource

Most utilities, PAs, and regulators do not treat building energy codes as a reliable energy efficiency resource. Consequently, PA programs supporting code adoption and compliance enhancement are referred to as non-resource programs, and the PAs do not claim savings from them. Further, many states throughout the U.S. do not have an energy efficiency resource standard (EERS), or a quantitative, long-term energy savings target for utilities (American Council for an Energy-Efficient Economy 2018); states without an EERS are likely not claiming savings. The following section provides a high-level overview of the non-resource efforts in the U.S. by region and identifies states that have an EERS.[11]

C&S Non-Resource Efforts by Region

Cadmus corresponded with representatives from each of the regional energy efficiency organizations, shown in Figure 7, to better understand utility and PA code activities.

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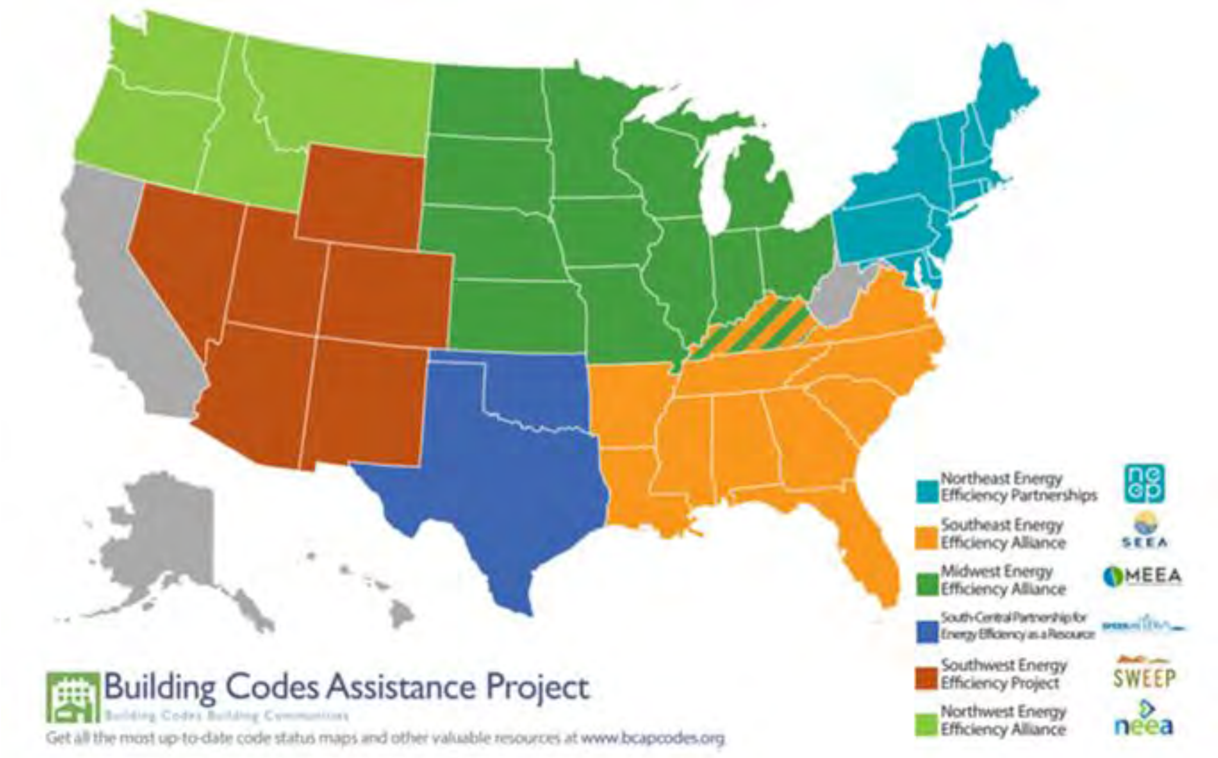
[11] All information on state Energy Efficiency Resource Standards is from the American Council for an Energy-Efficiency Economy EERS database.

Figure 7. Regional Energy Efficiency Organizations and Associated States



Source: Building Codes Assistance Project

Northeast

Massachusetts, Rhode Island, New York, and Washington D.C. are leading the attribution efforts in the Northeast. The Northeast Energy Efficiency Partnerships (NEEP) actively works to help educate utilities and PAs on attribution approaches. In its 2017 *Building Energy Codes for a Carbon Constrained Era: A Toolkit of Strategies and Examples,* NEEP recommends strategies to advance energy code development and adoption and to improve energy code administration to ensure performance levels are achieved. One such recommendation is to allow PAs to claim savings for compliance support activities. NEEP is also working on an exemplar of Massachusetts attribution efforts (Cadmus September 14, 2018).

National Grid, whose service territory spans Massachusetts, New York, and Rhode Island, is also a champion of attribution for code programs and has developed many resources for utilities and PAs to consider when looking to claim savings for code programs. Among those is the recent 2018 American Council for an Energy-Efficient Economy (ACEEE) paper, *Polishing a Hidden Gem: A Novel Evaluation Method for Energy Codes & Standards Programs* (Na'aim et al. 2018).

Every state in the Northeast has an EERS, although the EERS in Delaware is voluntary.[12] Many utilities and PAs also provide some form of support or funding for energy code education; however, with the exception of the Northeast states highlighted throughout this report, the efforts are considered non-resource. According to an interview with a NEEP senior policy manager, New Jersey Natural Gas provides robust energy code training; Vermont utilities support C&S through Efficiency Vermont; and New Hampshire utilities support energy code training by providing funding to NHSaves. Vermont and New Hampshire, described in greater detail below, have the most defined non-resource C&S efforts in the Northeast.

Vermont

Efficiency Vermont's (EVT's) 2018-2020 Triennial Plan (Vermont Energy Investment Corporation 2017) outlines the services and activities necessary to achieve the goals of the Vermont General Assembly's 2008 Energy Efficiency and Affordability Act and the 2016 Comprehensive Energy Plan (Efficiency Vermont 2018). Under the 2018-2020 plan, Efficiency Vermont will provide energy code training, market partner support, and technical assistance; distribute code materials; support energy code updates; and provide code assistance to various agencies, committees, and customers.

EVT has offered code support services for many years as part of its development and support services. According to the plan, "these efforts continued to be essential to Efficiency Vermont's efforts to deepen energy savings and to have a lasting, positive impact on Vermont households, businesses, institutions, and communities." EVT's 2017 savings claim summary does not indicate that EVT received credit for savings associated with the development and support services (Efficiency Vermont 2017). According to NEEP's *2013 Attributing Building Energy Code Savings to Energy Efficiency Programs* report: "the [Department of Public Safety] and [EVT] have had a long history of explorations of the concept of claiming energy savings from code support. Neither organization has found it necessary or worthwhile to endeavor to evaluate and assign savings for this activity" (Cadmus et al. 2013).

New Hampshire

New Hampshire's energy efficiency programs and policies are administered by NHSaves, a program jointly operated by New Hampshire utilities with oversight from the New Hampshire Public Utilities Commission. In 2016, the commission approved Order Number 25,932, establishing an EERS. In response to the EERS, NHSaves submitted the 2018-2020 New Hampshire Statewide Energy Efficiency Plan (New Hampshire's Electric and Natural Gas Utilities 2018).

The 2018-2020 plan details the "comprehensive customer outreach and education" New Hampshire utilities offer in support of energy codes. These activities include offering classroom and in-field training courses and disseminating educational materials to builders, inspectors, installers, contractors, real estate professionals, auditors, and Home Energy Rating System raters. The educational programs are

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[12] Northeast states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Washington D.C.

intended to "raise awareness of the benefits of energy-efficient products, homes, and businesses and establish a foundation for a more positive customer experience." No energy savings are attributed to PAs for these programs.

Southeast

The Southeast has made perhaps the least progress implementing utility C&S programs. According to a phone interview with a senior staff from the Southeast Energy Efficiency Alliance, utilities in the Southeast do not typically have a large role in the code adoption process and, while there has been some limited funding provided by utilities to support training, there are no utility energy code enhancement programs either (and as such, no utilities are claiming savings) (Cadmus September 17, 2018).

Two states in the Southeast, Arkansas and North Carolina, have an EERS. Virginia also has an EERS, but energy savings targets are considered voluntary since there are currently no regulatory requirements in place for energy efficiency programs. There is no EERS in Alabama, Florida, Georgia, Kentucky, Louisiana, Mississippi, South Carolina, or Tennessee.

Midwest

While no attribution approaches have been finalized in the Midwest, Illinois and Minnesota are moving toward claiming savings for code support efforts. Cadmus interviewed a senior policy manager at MEEA who reinforced that while many utilities and state agencies support some level of code training or education, none are currently claiming savings (Cadmus September 13, 2018).

Five states in the Midwest have an EERS: Illinois, Iowa, Michigan, Minnesota, and Ohio. Missouri and Kentucky have a voluntary EERS and the remaining states (Indiana, Kansas, Nebraska, North Dakota, South Dakota, West Virginia, and Wisconsin) do not have an EERS.

Missouri and Iowa, as described below, have included recommendations for code programs or initiatives in their energy efficiency plans. It is unclear if the utilities will seek attribution.

Missouri

Ameren Missouri's 2019-24 Missouri Energy Efficiency Investment Act plan proposes an "aggressive expansion of the portfolio," and includes six new education programs. One of these programs, the Home Building Code Compliance Education Program, is designed to provide energy code training and education to builders and other market actors "focused on high-energy impact measures that are commonly missed in residential code compliance." While the draft plan is publicly available, the appendices, which include draft program evaluation plans, are not (Ameren Missouri 2018).

Iowa

The 2016 Iowa Energy Plan, developed by the Inova Energy Group for the Iowa Economic Development Authority and the Iowa Department of Transportation, recommends the Department of Public Safety "work with local jurisdictions, utilities and other energy stakeholders to identify sources for long-term monetary support and resources for ongoing energy code education and training of local inspectors." It also cites the attribution efforts in Illinois as a way to claim savings for compliance enhancement as part of their programs (Inova Energy Group 2016).

South-Central

Oklahoma and Texas are the two South Central states that are supported by SPEER, the South-central Partnership for Energy Efficiency as a Resource. As stated on the organization's website, SPEER's purpose is "to advance the understanding and adoption of energy efficiency as a low-cost energy resource." SPEER currently administers an Energy Code Compliance Program that supports compliance by providing energy code training, outreach, and peer support to building professionals and code officials in Oklahoma and Texas. Savings from the program are not currently being claimed.

Texas was the first state to adopt an EERS in 1999; Oklahoma does not have an EERS.

Southwest

Arizona's deemed savings attribution approach has been the Southwest's flagship for claiming energy savings. Cadmus corresponded with the Southwest Energy Efficiency Partnership's (SWEEP's) buildings efficiency program director on the status of attribution in the Southwest. SWEEP confirmed that Arizona is the only state claiming savings for codes although each state, except Wyoming, has an EERS.

Utilities in Nevada, Colorado, and Utah currently provide funding for code trainings, although savings for these efforts are not being claimed. In 2018, according to its website, the Nevada Governor's Office of Energy, NVEnergy, and Southwest Gas have collaborated to fund energy code training. Efforts in Colorado and Utah are described in greater detail in the following sections.

Colorado

Since 2011, Colorado's Strategic Compliance Plan has served as the framework for energy code adoption and compliance throughout the state. The plan outlines strategic outreach and training efforts, including the role utilities and state departments play in the funding and implementation of such programs (Colorado Department of Local Affairs 2011).

According to Colorado Energy Office's website, Colorado has two IOU electric utilities, Black Hills Energy and the Public Service Company of Colorado (also known as Xcel Energy), regulated by the Public Utilities Commission. Through the State of Colorado's proceeding number 16A-0512EG, Xcel Energy agreed to co-fund energy code training in 2017 and 2018 with other stakeholders. Xcel Energy included the training in its 2017 DSM Annual Report, but no savings were claimed (Xcel Energy 2018). Energy code training is offered by other utilities and organizations as well, such as Garfield Clean Energy and Clean Energy Economy for the Region. The Colorado Energy Office also offers code training and technical assistance, as cited in ACEEE's State and Local Policy database. No attribution efforts are currently underway for code or standard support from these organizations either.

According to Colorado's Strategic Compliance Plan: "As a fellow home rule state that does not have a statewide mandatory energy code, Arizona's work to incorporate energy code implementation efforts into its energy efficiency targets offers a model for Colorado to consider."

Utah

Utah's 10-Year Strategic Energy Plan, published first in 2011, includes a recommendation for a statewide energy consumption reduction program with an energy code training component "supported through partnerships with Rocky Mountain Power and Questar [Dominion Energy] in conjunction with utility DSM programs" (Utah Office of Energy Development 2014).

In support of the plan, per the Utah Governor's Office of Energy Development's (OED's) website, OED has partnered with Rocky Mountain Power and Dominion Energy to offer the Building Talks Program. The Building Talks Program provides residential and commercial energy code training to builders, design professionals, code officials, and other building professionals, as well as other energy code resources. While there is little available information about the Building Talks program, a reference to the program is included in OED's 2018 budget (FY2018 Base Budget Presentation); Rocky Mountain Power has included energy code training as part of its 2017 portfolio level expenditures (Rocky Mountain Power 2018); and Dominion Energy lists "State Energy Program (SEP) Codes Training" in its 2018 budget notes (Dominion Energy 2017). SWEEP indicated that neither Rocky Mountain Power nor Dominion Energy are claiming savings for training efforts and this was confirmed through correspondence with the Managing Director of Energy Efficiency and Renewable Energy: "Presently, no savings are being claimed from this effort. It has been an ongoing discussion and the utilities are interested in the prospect of attribution, but it would require a [Public Service Commission] decision (and potentially state legislation)" (Cadmus October 1, 2018).

Northwest

The code support efforts of the Northwestern states are described in detail in the Pacific Northwest (Idaho, Montana, Oregon, and Washington) section above. Two of the four states, Washington and Oregon, have an EERS; Idaho and Montana do not have savings targets.

Hawaii

The State of Hawaii has committed to an aggressive clean energy goal of 100% by 2045. Under contract with the Hawaii Public Utilities Commission, Hawaii Energy acts as a PA and offers a suite of energy efficiency programs aimed at helping the state achieve its Energy Efficiency Portfolio Standards goal of a 4,300 GWh reduction by 2030 (Hawaii Energy 2018). A key feature of Hawaii Energy's 2018 Annual Plan is "advocacy and outreach support for advanced building energy codes and standards." C&S support is included as part of Hawaii Energy's Market Transformation Program "to drive energy savings in both public and private sectors" through adoption support at the county-level, code compliance improvement, and standards advocacy.

Since 2014, Hawaii Energy has participated in State Building Code Council monthly meetings, completed several code compliance studies, developed and distributed educational materials, offered circuit rider trainings, provided written and oral testimony in support of the 2015 IECC, created (and currently chairs) the State Building Code Council, Energy Efficiency Code Coordination Investigative Committee, advocated for county-level code adoption, and advocated for enhanced appliance standards through legislation.

To understand the savings associated with a more stringent energy code, Hawaii's Department of Business, Economic Development, and Tourism commissioned an energy impact forecast, completed in 2016, for the 2015 IECC with Hawaii amendments (Cadmus 2016). The savings forecast was used, in part, to inform a review "on behalf of the Public Utilities Commission to try to understand opportunities for energy savings from codes and standards activities in Hawaii, and what role the Hawaii Energy programs might be able to play in achieving these savings" (Mitchell-Jackson et al. 2016).

Hawaii Energy's team has since developed a logic model that "will guide how the Program will measure and propose energy savings attributable towards [its] resource acquisition goals." The team is actively researching attribution approaches that may be applied to their program (Cadmus, Hawaii Energy September 27, 2018).

Appliance Standards Policy Results by Jurisdiction

Summary of Findings

Table 3 provides a high-level overview of the role PAs play in appliance standards in several jurisdictions, including whether PAs support standards adoption, whether they support efforts to increase compliance with standards, and how savings are or are not attributed to PAs for their appliance standards activities.

Table 3. Summary of Appliance Standards Results

Jurisdiction	Status	Activity for Adopting Standards?	Activity for Compliance Enhancement?	Program Administrator Attribution Method
Formal Attribution Approach				
California	Program and attribution process in place more than 10 years	✓	✓	Evaluation using evidentiary record, expert panel; focused on adoption only
Pacific Northwest (ID/OR/MT/WA)	NEEA program in place for several years; attribution analyzed in recent years	✓		Attribution determined for energy efficiency advocates using evidentiary record and expert panel or evaluator
Massachusetts	Program in discussion	Proposed, likely in 2019		To be developed; likely to follow approach similar to codes
Rhode Island	Program likely following Massachusetts implementation	Likely		To be developed; likely to follow approach similar to codes
Arizona—SRP	Savings credited to program for several years	✓		Used deemed approach; method is being revised to analyze attribution
Deemed Attribution Approach				
Arizona—IOUs	Savings credited to program for several years	✓		Attribution limited to one-third of savings; evaluation required, but no information available
Full Savings Without Determining Attribution				
New York	Program supports adoption	✓		Counted without attribution
New Jersey	Program accounts for standards			No information available on attribution
Illinois	Utilities required to account for standards			None

Jurisdiction	Status	Activity for Adopting Standards?	Activity for Compliance Enhancement?	Program Administrator Attribution Method
Minnesota	Utilities can claim savings from standards			No information available
Hawaii	Hawaii Energy provides support	✓		No information available
Ontario	Standards subtracted from forecast load			No attribution
Manitoba	Utility supports appliance standards	✓		No analysis of attribution
No Attribution				
Vermont	State adopted new standards			No attribution

Evidence, such as the results of evaluations of California IOUs' C&S program, suggests that appliance standards offer a very large potential for energy savings, likely more than the savings possible through energy code upgrades and building code compliance enhancement efforts. Consequently, appliance standards could be a largely untapped resource from which PAs could harvest energy savings through efforts supporting standard adoption.

Activities to adopt standards at the state level have ramped up in recent years, while the process of adopting standards at the federal level has slowed. A recent study by the Appliance Standards Awareness Project (ASAP) and ACEEE identified a large number of standards that could be adopted by states, and some states have moved ahead to adopt some of these standards (Mauer et al. 2017). Much of the information in this section was provided through an interview with a representative of ASAP (Cadmus September 18, 2018).

The same study notes that most states have to adopt standards through legislation, so any effort by PAs to influence standard adoption would have to be directed at the legislative process. This policy issue could require PAs to take on an unaccustomed role and could be an obstacle to some advocating for appliance standards. California is one major exception to standards being adopted through legislation because the California Energy Commission has the authority to adopt state appliance standards (as well as building codes). This has made it more feasible for PAs in California to engage in efforts to support appliance standards and get energy savings credit.

Given the relatively recent state activities adopting standards and the usual process of requiring adoption through legislation, PA involvement has been modest to date, and processes for attributing savings credit to PAs have been limited.

Formal Attribution Approach

Overall, fewer jurisdictions attribute energy savings from standards than building energy codes, although there has been some increase in the number of jurisdictions that do so in recent years. In 2014, Cadmus found that only California had a process for attributing savings to appliance standards; since then four additional jurisdictions have conducted formal attribution analyses or are likely to initiate formal attribution processes. The following sections detail how each state is claiming savings for their standard adoption support or compliance enhancement programs.

California

In California, the IOUs have received energy savings credit for appliance standards supported through their C&S program based on an approach essentially the same as that described earlier for building codes. In addition to savings credit for California standards, the IOUs can get credit for adoption of federal standards they have supported. In most cases, federal standards are adopted through the U.S. Department of Energy's procedures, but some federal standards are adopted legislatively. The attribution process for federal standards has been tailored to account for the unique features of the federal adoption process.

To date, the IOUs have not claimed savings for efforts to improve compliance with appliance standards. Their most recent program includes efforts to increase compliance with standards, so it is likely they will want to claim savings credit for increased compliance at some point, and this will trigger development of a method to assess attribution.

Pacific Northwest (Idaho, Montana, Oregon, Washington)

Just since 2012, NEEA and other Pacific Northwest parties have been involved significantly in the adoption of 20 federal appliance standards (State of Oregon 2018). According to recent estimates from NEEA's quarterly performance report, appliance standards contribute 28% of regional electricity savings, more than any other regional energy efficiency investment (NEEA 2018).

NEEA has supported recent studies to assess the effectiveness of NEEA's standard advocacy efforts and the influence of NEEA and other organizations on energy savings from adoption of various standards. NEEA has not specified a standardized methodology for calculating attribution, but the basic approach starts with data collection through a literature review and interviews with knowledgeable stakeholders. The evaluators then assess NEEA's effectiveness in the adoption process by identifying how well it accomplished each step in its standard development logic model. Calculation of attribution to the efforts of energy efficiency advocates then follows an approach like that used for the evaluation of California IOUs' C&S program described earlier. It relies on estimating the relative significance of barriers to standard adoption and the relative influence of different stakeholders in overcoming those barriers (Cadmus June 2016; Cadmus 2018). The attribution assessment has been done in evaluations so far by either an expert panel or the evaluator.

Massachusetts and Rhode Island

Although PAs have not implemented appliance standard support programs yet in either Massachusetts or Rhode Island, we anticipate that they will in the near future. ASAP has been working with stakeholders in both states for almost 10 years, and both have adopted state standards over that period (Cadmus September 18, 2018). PAs in Massachusetts have put forth preliminary specifications for an appliance standard advocacy program, which are being considered in the policy making process. National Grid is a leader of these efforts in Massachusetts and, as the only IOU in Rhode Island, we anticipate it will make a similar push there because appliance standards development and advocacy are one step in its overall C&S initiative.

Given that the programs are undefined, the approach for evaluating attribution has not been developed yet in either state. However, given the precedence in the building codes area, Cadmus expects that the regulators in both states will pursue formal attribution approaches similar to the approaches applied to the building code support programs.

Arizona—SRP

SRP's Appliance and Equipment Standards program is designed to increase awareness of and advocate for more robust efficiency standards at the national, state, and local levels. SRP has claimed energy savings from its efforts influencing the statewide adoption of a minimum efficiency standard for pool pumps effective January 1, 2012. The legislated standard applies to pool pumps of one horsepower and larger and requires pumps that can operate at a minimum of two speeds. SRP takes credit for energy savings attributable to its advocacy work, contributing to Arizona's change in standards from single-speed pumps to two-speed pool pumps.

The savings credited to the standard interact with savings SRP claims for its pool pump incentive program. SRP provides incentives for variable speed pool pumps, which are more efficient than the two-speed pumps required by the standard. SRP claims 50% of the savings for a two-speed pump compared to a single-speed pump, and attributes those savings to its standards program.

SRP's initial approach was to set attribution at the 50% level. For the next program evaluation, Cadmus understands that SRP will use a process like the one used to determine attribution for the codes program to reassess the reasonableness of this attribution factor.

Deemed Attribution Approach

Arizona—IOUs

As for building codes, the Arizona IOUs have claimed savings for appliance standards under the ACC regulations. TEP's Energy Codes and Standards Enhancement Program is designed to improve compliance with current energy codes and standards and support the adoption of newer codes and standards (TEP 2017). APS' Building Codes and Appliance Standards Initiative offers compliance enhancement support to code officials, building professionals, and other market actors (APS 2017).

The regulation allows the IOUs to claim up to one-third of the savings from appliance standards as quantified through a measurement and evaluation study conducted by the utility. The regulation does not say the IOUs can claim electricity savings from appliance standards so there is some ambiguity about whether they are claiming the savings for credit toward their savings targets. The IOUs have not allocated budgets to evaluate savings either so there is uncertainty about whether or how they are claiming savings from standards.

Full Savings without Determining Attribution or Attribution Permitted without Approach Specified

Given the status of appliance standards advocacy by PAs in most states, the most common situation is that savings from standards are included in savings and load forecasts, but attribution is not estimated, or the estimation method has not been defined yet. Several jurisdictions in this situation are described briefly below.

New York

The Systems Benefit Charge program administered by NYSERDA includes the Advanced Energy Codes and Standards Program. One component of this program has been contributing to the development of appliance and equipment standards, specifically those not covered by federal standards (NYSERDA 2013). Savings from standards are accounted for, but no effort has been made to determine attribution.

In his 2018 State of State address, Governor Cuomo directed NYSERDA to propose new 2025 energy efficiency targets by Earth Day, April 22. Appliance standards were one key component of the targets, but they have not been implemented to date.

New Jersey

In 2018, New Jersey's Clean Energy Act, Bill A-3723, required utilities to establish energy efficiency and peak demand reduction programs to be approved by the BPU. The BPU is required to adopt performance indicators for each utility to establish reasonably achievable targets for energy usage reductions and peak demand reductions, taking into account appliance efficiency standards.

The act permits utilities to apply all energy savings attributable to programs available to its customers, as well as energy efficiency standards. However, there has been no information to date about how savings will be attributed to codes and standards programs.

Illinois

Illinois' FEJA requires utilities to include proposals for C&S programs and utility procurement plans must include an analysis of the impact of energy efficiency appliance standards, both current and projected, as well as opportunities to expand the programs.

In response to these requirements, Illinois utilities have joined together for a potential statewide code compliance enhancement program. However, they have not taken similar steps yet to address appliance standards and no information is available yet on how they might determine savings and attribution.

Minnesota

The Minnesota Next Generation Energy Act allows utilities to claim savings credit for appliance standards toward the annual energy savings target. No information is available yet on the process for estimating savings or attribution (State of Minnesota 2017).

Hawaii

In addition to its building codes activities, Hawaii Energy provides advocacy and outreach support for advanced standards. One role of the Department of Business, Economic Development, and Tourism's 2016 energy impact forecast was to understand opportunities for energy savings from standards activities in Hawaii, and what role the Hawaii Energy programs might play in achieving these savings. Hawaii Energy's team has since developed a logic model to guide its standards and codes activities (Mitchell-Jackson et al. 2016).

In the standards area, one strategy Hawaii Energy is implementing is requiring efficiency levels above current codes and standards (Hawaii Energy 2018). Hawaii Energy is also increasing strategic efforts advocating for minimum product standards for electric appliances brought to Hawaii. Hawaii Energy will partner with other agencies to understand the market dynamics of appliances shipped to Hawaii, their shelf life, and the impact California's appliance standards may have on Hawaii in the absence of Hawaii standards. While Hawaii has not adopted any state standards, the Standards Enhancement target for program year 2018 is the implementation of three engagements to advance legislation for Hawaii to explore and adopt state appliance efficiency standards. A bill was developed to adopt California standards, but it did not pass this year.

How savings and attribution will be addressed for appliance standards has not been determined.

Ontario

As for codes, savings from forecast appliance standards are subtracted from the gross reference load forecast. There is no information indicating LDCs engage in activities to support and standards, and no attempt is made to assess attribution.

Manitoba

As it does for building codes, Manitoba Hydro engages in activities to support appliance standards. Forecast savings are counted toward the utility's savings goals without any analysis of attribution.

No Savings: Standards Considered Non-Resource or No Program

Vermont

In 2016, Vermont passed a law (House Bill H.410) adopting 16 new state appliance standards (Granda 2018). The adopted standards are the complete set of standards recommended by ASAP. The state also adopted all existing federal standards into law to avoid the possibility of a rollback at the federal level.

Like efforts supporting building energy codes, we found no evidence that EVT or any other entity in Vermont would claim savings from the standards.

Other States

There are activities in several states supporting the adoption of appliance standards that have not involved PAs. These include the following:

- Connecticut: standards can be adopted administratively
- Oregon: an executive order has been issued for the state to develop a plan to adopt new standards
- Washington: a bill was proposed in 2018 to adopt 19 new standards, but it has not passed

Findings

This report provides a review of how various jurisdictions in North America attribute or determine the share of energy savings to credit to program administrators for their efforts supporting codes and standards. To provide a broader context, we also documented the status of PA involvement in codes and standards in jurisdictions where there is no process for crediting savings to the PAs' efforts.

Our key findings from this study are presented below:

Energy savings from building codes and appliance standards affect load forecasts and utility revenue requirements. Load forecasts based on econometric models capture the effect of existing codes and standards and can be adjusted to account for new codes and standards. Similarly, end-use load forecasts can adjust estimates of end-use loads to account for existing or new codes and standards. Load forecasts and utility revenue requirements can be adjusted to account for adopted codes and standards that have known effective dates. The savings from codes and standards are applied, along with estimated energy-efficiency program savings, to the energy forecast estimates based on underlying load growth to produce the net load growth estimate. The savings from new codes and standards can be a significant fraction of the total energy-efficiency savings.

The relationship between programs to support codes and standards and other DSM programs is complex. Most PAs and regulators recognize that adoption of more stringent building codes and appliance standards by policy makers make it more difficult for conventional DSM programs to produce energy savings. This has motivated several PAs to seek ways to explicitly support the adoption of codes and standards and enhance compliance with them, and some of these PAs have sought to claim energy savings attributable to their efforts. Some PAs have suggested that conventional DSM programs ready the market for the adoption of new codes and standards and that these DSM programs should receive indirect energy savings credit for allowing these codes and standards to be adopted sooner than they would otherwise be. This argument is similar to the logic underlying the BC DSM regulation issued in 2008. Another approach that has been considered is increasing the amount of codes and standards savings attributed to the PA because prior PA programs helped ready the market for adoption of the subsequent codes and standards. None of the jurisdictions that Cadmus investigated outside BC have instituted a policy or process for measuring and attributing such savings, possibly because of the complexities involved.

***While attribution continues to be a topic of interest among utilities, PAs in most states and jurisdictions do not claim savings for their C&S efforts*.** Some PAs that do not claim attribution for C&S savings do fund code enhancement programs or otherwise provide C&S support that result in energy savings that are reflected in their net load forecasts and revenue estimates.

No standardized attribution method exists, but most methods have some common features. Attribution approaches for C&S programs implemented by PAs range from no attribution to attribution based on a rigorous, formal analytic process. There is a trend toward formalized approaches, especially in cases where PAs are engaged in well-defined code or standard programs and they have specific energy savings goals to meet. The most common features of the formal approaches include basing attribution on a documented evidentiary record of influence and relying on the professional judgment of objective experts or evaluators to assess attribution, usually through a Delphi panel process.

The number of jurisdictions attributing energy code savings has increased. Six jurisdictions have formal processes for attributing savings to building code activities. This is a three-fold increase since 2014. PA efforts in these areas include both code adoption and code compliance support. Formal attribution processes are split about equally between code adoption and code compliance enhancement efforts. The number of jurisdictions with deemed attribution approaches has remained at three, though the jurisdictions have changed.

Number of jurisdictions attributing appliance standard savings has increased, but there are still relatively few that do. Counting the Pacific Northwest as a single jurisdiction, five jurisdictions have, or are expected to have soon, a formal or deemed process for attributing energy savings to standards activities by PAs. PA standard support activities have focused almost exclusively on adoption rather than compliance.

Standards advocacy offers opportunities for significant energy savings if barriers can be overcome. While the number of PAs advocating for appliance standards and the number of jurisdictions allowing PAs to receive energy savings credit for these efforts has been small to date, experience indicates that appliance standards may offer the potential for larger energy savings opportunities than new building codes or improved code compliance. PAs have been slower to get involved with appliance standards for several reasons including PAs are less familiar with appliance standards and the common mechanism of adopting standards legislatively is a political process in which PAs are reluctant to get involved. Identifying and overcoming these barriers could open more opportunities for PAs to support appliance standards.

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BC Hydro
Power smart

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix DD

Energy Studies Process Internal Audit

SUMMARY AUDIT REPORT

OPERATIONS

ENERGY STUDIES PROCESS AUDIT

Q3 F2019

OCTOBER 28. 2018

AU1908CIPD

Prepared By:

B. Mo (SINTEF)
A. Helseth (SINTEF)
J. Chong
R. Prinja
A. Lagnado

Distributed To:	**D. Sherbot**	**D. Wong**
	H. Matthews	**C. O'Riley**
	M. Poweska	**Audit & Finance Committee**

Energy Studies Process Audit F2019

AUDIT TYPE	AUDIT RATING
RISK BASED AUDIT	G

Legend:

Minor issues and impacts identified

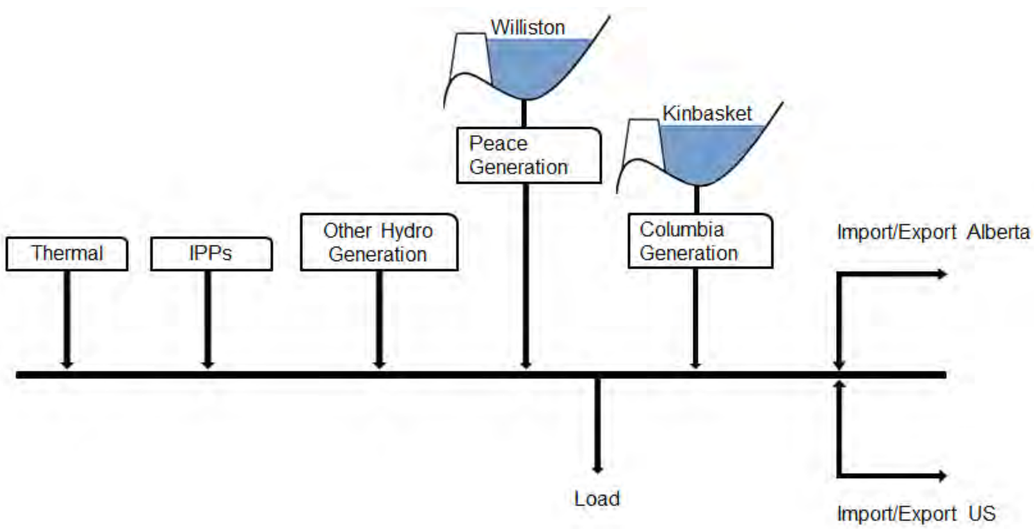
Critical issues and impacts identified

Audit Objective

- To evaluate whether the monthly Energy Studies process reliably supports operations, financial and strategic planning at BC Hydro.
- This audit was conducted in conformance with the International Standards for the Professional Practice of Internal Auditing.

Background

- BC Hydro's primary source of seasonal and multi-year operational flexibility is the Kinbasket reservoir on the Columbia River and Williston reservoir on the Peace River. Together, the total storage in these reservoirs is approximately 90% of the total storage capability in the system.
- Hydropower generation from these plants on the Peace and Columbia is coordinated with the remainder of the BC Hydro Generating Stations, generation from independent power producers, and other energy sources to meet regional demand. Exchange with neighbouring power markets in Canada and the US are taken into account in the coordination. An illustration is provided in the figure below.



- BC Hydro's objective for system coordination is to maximize risk neutral long-term net revenue from operations. Water should be valued to provide strategies for when to use and when to store water in the reservoirs. Without good strategies, non-optimal system states could occur over time where:
  - Reservoirs are full and more inflow will lead to spillage.
  - Reservoir levels are critically low, resulting in import at high prices or curtailment of demand.
- Operational strategies can be found by applying mathematical models to compute the marginal value of water for different points in the future.

Energy Studies Process Audit F2019

- If the marginal value of water is above market price at a given time, the best decision is to store water for generation at a later time. If the marginal value is below market price then the water is used for generation.
- To compute accurate water values, the long-term scheduling models should reflect both the dynamics and constraints that affect operational flexibility, and the uncertainties that impact future reservoir operation (such as inflows and market prices).

- BC Hydro produces an Energy Study every month. The primary objective is to forecast, over a five year horizon, an optimal set of reservoir and generating station operations and market transactions under current forecasts of market, inflow, and weather conditions.
- The Energy Study process consists of numerous proprietary models which are developed and maintained by a specialized team in Generation System Operations. Some key models have been reviewed externally over the last 20 years as part of continuous improvement efforts.
- Audit Services engaged SINTEF Energy Research as subject matter experts to review the Energy Studies process and selected key models. SINTEF has more than 40 years of experience in developing models for planning and operation of hydrothermal power systems.

Key Findings

Summary

- BC Hydro has a well-established Energy Studies process in place. Governance is effective with adequate level of oversight, and responsibilities are well understood across the team.
- Key models developed are appropriate and the methodologies applied are in line with leading industry practices. The Energy Study process can be further automated to reduce cycle time and free up resources.
- Energy Study reports are prepared on time; however they do not serve short-term operational planning needs.

Governance

- Effective management oversight is in place. Energy Studies results are reported monthly to key user groups at BC Hydro and Powerex, and quarterly to the Operations and Planning Committee of the Board. During the interim, weekly meetings are also held with management to review and discuss results and related variances.
- High level strategies and objectives exist to guide the group. BC Hydro has developed in-house models for long-term scheduling. These models are built to maximize risk neutral long-term net revenue. The strategy to develop custom models is appropriate due to the complexity of the Columbia River Treaty.
- Team structure, roles, and responsibilities are clearly defined. Succession planning is in place. The System Optimization team is part of the Operations Planning group within Generation System Operations. The team is comprised of four specialized engineers with backgrounds in various disciplines such as system design, hydro-technical, and water resources.
- The Energy Studies financial policy is outdated and requires updating. The policy defines approval levels for domestic buy and sell prices, but some details are outdated such as titles and positions.

Energy Studies Process Audit F2019

Energy Studies Process

Models and methodologies for long-term scheduling of hydropower-dominated systems have been widely used in the industry for the last 50 years. Countries such as Brazil, Canada, Norway, Sweden, New Zealand and Iceland all have traditions for using mathematical models for finding the long-term optimal use of water in their hydropower-dominated systems.

- Methodologies applied to optimize the two major river systems (Columbia and Peace) separately and then coordinated are appropriate and reasonable. The Energy Study cycle time could be improved as it currently takes approximately three weeks to complete. Further automation would provide more updated prices and free up labour resources.
- Key models are developed using standard development tools and programming languages. Source codes are tracked and retained in a version control system. While most key models can accommodate changes in the system, the Peace model is less flexible as it is based on legacy software codes. Management is working on a replacement solution.
  - Developer documentation for the models should be enhanced to ensure model maintenance, quality review, and knowledge transfer.
- Inputs and assumptions used in the various models are generally reasonable. Model inputs are primarily comprised of load forecast, temperature, water inflows, market prices, outages, and electricity purchase agreements. Changes in assumptions are discussed amongst the team, logged via version control, and communicated externally.
- Comprehensive process is in place to review the Energy Study results. This includes weekly discussions within Generation System Operations and with Powerex, and monthly comparisons to previous results.
- No regular backtesting is performed in the current process. Typically, calculated marginal prices would be compared with market prices to assess model performance. Given there are no market prices for the BC Hydro system, this would not be possible. However, actual reservoir operations could be compared with model simulation.

Outputs

- Monthly Energy Study Report is distributed timely to key users in Finance, Generation System Operations, Powerex, and BC Hydro.
- Although water values for the short-term horizon are computed from the Energy Study process, some users indicated the information provided does not always serve short-term operational needs.
  - The Operations Planning group often relies on a less sophisticated model to aid with short-term system planning as information provided from the Energy Studies may not represent the current state of the system due to outdated inputs.

Management Comments and Action Plans

- Management agrees with the recommendations in the audit report and will take actions to address them. Two recommendations will be completed by March 31, 2019. The remaining recommendations will be reviewed by June 30, 2019 as part of an overall Energy Study model development strategy.

MANAGEMENT AUDIT REPORT

OPERATIONS

ENERGY STUDIES PROCESS AUDIT

Q3 F2019

OCTOBER 28, 2018

AU1907OP

Prepared By:

B. Mo (SINTEF)
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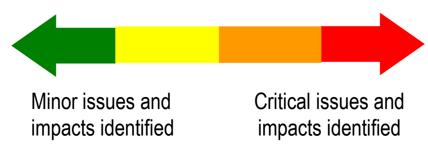
Energy Studies Process Audit F2019

CONTENTS

Legend:



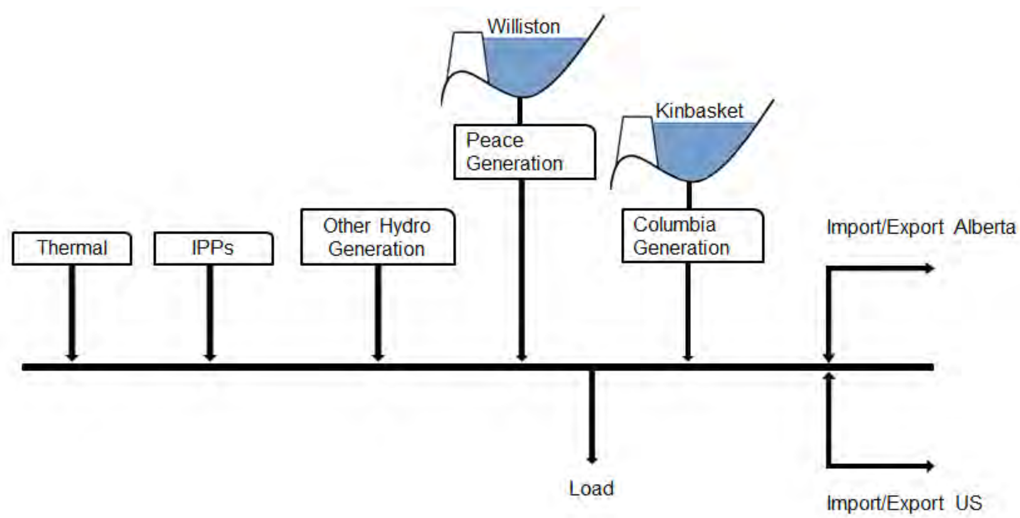
Energy Studies Process Audit F2019

1a. Executive Summary

- For each audit, Audit Services provides two separate Audit Reports. The first report is a Summary Audit Report prepared for Senior Management and the Audit & Finance Committee (AFC) of the Board. This Management Audit Report provides additional information and related audit recommendations for management purposes and will not be presented to the AFC.
- Management should also refer to the Summary Audit Report for high level conclusions and findings.

1b. Background

- BC Hydro's primary source of seasonal and multi-year operational flexibility is the Kinbasket reservoir on the Columbia River and Williston reservoir on the Peace River. Together, the total storage in these reservoirs is approximately 90% of the total storage capability in the system.
- Hydropower generation from these plants on the Peace and Columbia is coordinated with the remainder of the BC Hydro Generating Stations, generation from independent power producers, and other energy sources to meet regional demand. Exchange with neighbouring power markets in Canada and the US are taken into account in the coordination. An illustration is provided in the figure below.



- BC Hydro's objective for system coordination is to maximize risk neutral long-term net revenue from operations. Water should be valued to provide strategies for when to use and when to store water in the reservoirs. Without good strategies, non-optimal system states could occur over time where:
  - Reservoirs are full and more inflow will lead to spillage.
  - Reservoir levels are critically low resulting in import at high prices or curtailment of demand.
- Operational strategies can be found by applying mathematical models to compute the marginal value of water for different points in the future.

Energy Studies Process Audit F2019

  - If the marginal value of water is above market price at a given time, the best decision is to store water for generation at a later time. If the marginal value is below market price then the water is used for generation.
  - To compute accurate water values, the long-term scheduling models should reflect both the dynamics and constraints that affect operational flexibility, and the uncertainties that impact future reservoir operation (such as inflows and market prices).
- BC Hydro produces an Energy Study every month. The primary objective is to forecast, over a five year horizon, an optimal set of reservoir and generating station operations and market transactions under current forecasts of market, inflow and weather conditions.
- The Energy Study process consists of numerous proprietary models which are developed and maintained by a specialized team in Generation System Operations. Some key models have been reviewed externally over the last 20 years as part of continuous improvement efforts.
- Audit Services engaged SINTEF Energy Research as subject matter experts to review the Energy Studies process and selected key models. SINTEF has more than 40 years of experience in developing models for planning and operation of hydrothermal power systems.

1c. Audit Objective and Scope

Objective

- Evaluates whether the monthly Energy Studies process reliably supports operations, financial and strategic planning at BC Hydro.

Scope

- The Audit primarily focuses on the following areas:
  - **Governance** – strategies, objectives, roles and responsibilities
  - **Energy Studies process** – models, inputs, assumptions, validation, change management, data management, documentation
  - **Outputs / Reporting** – review and approval, timeliness, user expectations
- This audit was conducted in conformance with the International Standards for the Professional Practice of Internal Auditing.
- The audit team was supplemented by two subject matter experts from SINTEF:
  - Birger Mo is a senior research scientist at SINTEF since 1987, working with load forecasting, risk management, hydro scheduling and hydrothermal market modelling. He obtained his PhD in 1991 in Engineering Cybernetics from the Norwegian University of Science and Technology. He participated in previous BC Hydro reviews and consulting work related to the Peace model (1998) and Columbia modelling and coordination (1999 and 2008).
  - Arild Helseth is a research scientist at SINTEF since 2008, working with development and analyses related to hydrothermal market models and medium-term hydropower scheduling models. He obtained his PhD from the Norwegian University of Science and Technology, Department of Electric Power Engineering, in 2008.

Energy Studies Process Audit F2019

1d. Findings, Recommendations and Management Action Plans

Summary

BC Hydro has a well-established Energy Studies process in place. Governance is effective with appropriate level of oversight, and responsibilities and accountabilities are well understood across the team.

Key models developed are appropriate and the methodologies applied are in line with leading industry practices. The Energy Studies process can be further automated to reduce cycle time and free up resources.

Energy Study reports are prepared on time and contain an appropriate level of detail; however they do not serve short-term operational planning needs.

Governance

Overall Conclusion

Effective governance is in place over the Energy Studies process. High-level strategies and objectives are set up for the team. Responsibilities and accountabilities are well understood across the team.

Key Conclusions and Findings

- Adequate level of management oversight is in place. Energy Study results are reported monthly to the Executive VP, Operations, key user groups at BC Hydro and Powerex, and quarterly to the Operations and Planning Committee of the Board. Weekly meetings are also held with management to review and discuss results and related variances.
- High level strategies and objectives exist to guide the group. BC Hydro has developed in-house models for long-term hydrothermal scheduling. These models are built to maximize risk neutral long-term net revenue. Strategy to develop in house models is appropriate because of the complexity of the Columbia River Treaty.
    - An annual Generation System Operations (GSO) business plan identifies objectives, metrics, and major activities for all the groups within GSO. At the activity level, each group has a monthly action plan tracker to track monthly progress on specific action items.
- Team structure, responsibilities and accountabilities are clearly defined and well understood. The System Optimization team is part of the Operations Planning group within GSO. The team is comprised of four specialized engineers with backgrounds in various disciplines such as system design, hydro-technical, and water resources.
    - Two team members rotate each month to run the Energy Studies process, while the other two members are tasked with model development, ad-hoc enquiries and other team priorities.
- Succession planning is in place and formally documented. Most of the 85 models involved in the Energy Studies process are documented in the Model Inventory, and have been assigned a primary and a secondary owner. The secondary owner maintains the assigned model when the primary modeller is not available, and also reviews the model for any coding errors.

Energy Studies Process Audit F2019

- A secondary owner has not yet been identified for COSTA (Columbia River Treaty Simulator) and CODA (Domestic allocation optimizer). Discussions with the team indicated that this succession gap can be remediated quickly.

- The Energy Studies financial policy is outdated and requires updating. The current policy defines approval levels for domestic buy and sells prices when there is a threshold change from the last approved price. This policy however needs to be reviewed and updated as it was last edited in March 2011, and some details are outdated such as titles and positions.

	Recommendations	Management Action Plans
	Governance	
1	Continue working on the succession matrix to find a secondary owner for COSTA and CODA models.	Management will formalize the succession matrix by March 31, 2019.
2	Review and update Energy Studies financial approval policy.	Management will review and re-publish the policy by March 31, 2019.

Energy Studies Process

Overall Conclusion

The Energy Studies suite of models is appropriate and the methodologies applied are in line with leading practices. Models have been developed using standard development tools and programming languages. Continuous enhancements have been made to the key models over the last decade particularly in the optimization for the Columbia River.

Key areas for improvement include process automation, upgrading legacy software coding for the Peace River model, refining documentation, and periodically backtesting to gain more insights into model performance.

Key Conclusions and Findings

Overview

- Models and methodologies for long-term scheduling of hydropower-dominated systems have been widely used in the industry for the last 50 years. Countries such as Brazil, Canada, Norway, Sweden, New Zealand and Iceland all have rich traditions for using mathematical models for finding the long-term optimal use of water in their hydropower-dominated systems.

Methodology and Approach

- Methodologies applied to optimize the two major river systems (Columbia and Peace) separately and then coordinated are appropriate and reasonable. BC Hydro currently uses internationally recognized methodologies (SDP for Peace and SSDP for Columbia) for calculating water values.
  - SDP (Stochastic Dynamic Programming) method is the oldest and traditionally most applied. In this method the expected future profit as function of the state variables (i.e. reservoir levels, inflows) are calculated and stored for discrete values.

Energy Studies Process Audit F2019

- SSDP (Stochastic Sampling Dynamic Programming) method calculates the future profit for each specific scenario assuming that decisions are taken with respect to all possible future scenarios. SSDP is particularly well suited to deal with stochasticity (uncertainties in input parameters) represented by historical observations and scenario dependent constraints.
- SDDP (Stochastic Dual Dynamic Programming) would allow optimization of the two rivers in one unified model instead of maintaining and coordinating two models. However, there is no straightforward solution to include all Columbia (state and scenario dependent) constraints in the SDDP approach. Consequently, BC Hydro's current decoupling method seems reasonable.

- The Energy Study cycle time could be improved as it currently takes approximately three weeks to complete. Presently, there are many manual components and synchronizing points which slow down the process. Further automation would provide more frequent basin price updates and free up labour resources.

Key Models

- The Market Model methodology is appropriate for forecasting future electricity spot prices. Market Model is an econometric (regression) model that provides forecasts for future electricity spot prices for the electricity market in the US that BC Hydro can sell to or buy from as function of important drivers.
  - The Market Model was last reviewed externally in 2005. The basic methodology behind the model has been more or less unchanged for many years, but model code was rewritten as part of the Comet Improvement Project implemented in 2016. Model parameters are updated yearly based on the availability of new observations.
  - Econometric models are statistical models which in their simplest form can be a linear regression between observed gas price and electricity prices based on historical prices.
- The methodology used to schedule the Peace River system is reasonable. The Peace model was implemented over 30 years ago and has been extensively tested through years of operational use. The team has reported limited familiarity with the legacy code used in the Peace model. Management is working on a replacement solution with updated coding.
  - The current model does not incorporate a snow state variable which could result in underestimating probabilities for prolonged wet or dry periods when computing water values.
  - Peace Model is an optimization model where the Williston reservoir level and the Henry Hub gas price are treated as state variables. The model uses historical inflow sequences (from 1973) to represent uncertainty in inflow, assuming that each inflow scenario is equally likely to happen in the future.
    - Optimization is a mathematical model where the optimal decision is determined according to a defined objective function and subject to a set of constraints.
- The methodology used to schedule the Columbia River system (COSTA and MUREO) is appropriate and considered best practice. However, given the complexities of the Columbia River system and the River Treaty, more effort should be put into verifying the results of the implemented models. Verification could be done by benchmarking against a second model which the team is currently developing with a university research group.
  - COSTA is the new Columbia River Treaty simulator designed to implement the complex rules of the Columbia River Treaty. Results are used as constraints in downstream models to optimize and simulate the operation of Kinbasket and Arrow reservoirs.

Energy Studies Process Audit F2019

- A simulation is a computer based imitation of the physical operation of the system.
- MUREO is the new optimization model for the Columbia system and uses the outputs from COSTA. The main results from MUREO are an optimal strategy for operation of the major reservoirs in the Columbia system.

- SOPHOS is a rule-based system simulator and is appropriate; however the formulation could be more generalized. Parts of the simulator could be based on optimization and would make it more adaptable to changes in the BC Hydro system and applicable to other reservoirs.
  - The loading of generation plants as well as marginal prices would come as direct results of optimization.
  - SOPHOS prepares input data to the Columbia and Peace optimizers, then simulates system operation based on the water values and recommended plant discharges obtained from those optimizers.

Models Development

- Key models are developed using standard development tools and programming languages such as Java, Fortran, and AMPL. Source codes are tracked and retained in version control. While most of the key models are responsive to accommodate changes in the system, the Peace model is less flexible and based on legacy codes as discussed previously.
- User guides and developer documentation are available for most of the key models reviewed, however improvements are required. Developer documentation for the Peace model is missing and the updated developer documentation for MUREO, COSTA and SOPHOS are not self-explanatory.
  - Comprehensive and clear developer documentation is critical to ensure model maintenance, quality review, and knowledge transfer to other developers within the team.

Inputs and Assumptions

- Inputs and assumptions used in the various models are generally reasonable. Model inputs primarily comprised of load forecast, temperature, water inflows, market prices, outages, and electricity purchase agreements. Changes in assumptions are discussed amongst the team, logged via version control, and communicated externally.
  - Input data has been stored in a version control system since 2009.
  - Interviews indicated that timing of the load forecast and level of details provided could be enhanced for the purposes of improving the Energy Studies process.
- One area of improvement relates to price inputs into the Market Model. Considerations should be given to incorporate the California market prices into the Market Model to obtain better water values. Main inputs to the Market Model include forward market prices for gas at Henry Hub and forward prices for electricity at Mid-C.
  - The forecasted power prices for the different US markets such as California are a significant factor for the calculated BC Hydro marginal prices, and decisions on import/export and generation.

Validation & Backtesting

- Comprehensive process is in place to review the Energy Study results. The review process comprises of weekly discussions within GSO and with Powerex, monthly comparisons to previous results, and a simplified short-term model (Ultralight model).

Energy Studies Process Audit F2019

- No regular backtesting (or benchmarking) is performed in the current process. Typically, calculated marginal prices would be compared with market prices to assess model performance. Given there are no market prices for the BC Hydro system, this would not be possible. However, actual reservoir operation could be compared to model simulations.
  - Backtesting could be easier to perform if the process is further automated as discussed previously.

	Recommendations	Management Action Plans
	Energy Studies Process	
3	**Methodology/Approach** - Identify opportunities to further automate the manual components of the Energy Studies process.	- Management will develop an Energy Study model development strategy by June 30 2019 that will address the priority and timing of actions to be taken relating to recommendations #3 to #11. - Management will review the existing process, identify areas to automate and create an implementation plan.
4	**Key Models** - Finalize a replacement solution for the Peace Model (with code from MUREO). - Consider including a state variable for snow in the optimization methodology used for the Peace River.	- Management will review the status of the Peace optimization and decide whether to replace the existing model.
5	**Key Models** - Benchmark the Columbia River optimization models with results obtained by a second model (such as the current university research project).	- Management will review options for benchmarking the Columbia River optimization models.
6	**Key Models** - Consider generalizing the SOPHOS simulator and adding a daily optimizer.	- Management will review options for generalizing SOPHOS.
7	**Model Development** - Improve developer documentation for the key models. Documentation should be stand-alone, and contains sufficient level of details. - Provides description of each model's key properties, its underlying assumptions, and what is actually being modelled.	- Management will review current developer documentation and update documentation standards.

Energy Studies Process Audit F2019

	Recommendations	Management Action Plans
8	**Inputs and Assumptions** ❑ Consider adding California pricing to the Market Model to obtain better water values.	❑ Management will initiate a policy review of the use of California pricing in the Energy Studies.
9	❑ Continue working with the Load Forecast group on timing of the load forecast and level of details provided.	❑ Management will initiate a review of how the load forecast is operationalized.
10	**Validation & Backtesting** ❑ Investigate options for periodic benchmarking or backtesting of key model results.	❑ Management will review options for benchmarking and backtesting of key model results.

Outputs

Overall Conclusion

Energy Study Reports are prepared on time and results are communicated to Management on a regular basis; however the results do not provide sufficiently strong signals for short-term operational planning purposes as reports are only released once a month.

Key Conclusions and Findings

- Monthly Energy Study Report is distributed timely to key users with narratives to explain material variances. Board updates on Energy Studies results are also produced on a quarterly basis. The Report is widely distributed to key stakeholders in Finance, Generation System Operations, Powerex, and BC Hydro. Each monthly package contains the following:
  - Operational Risk Summary provides status of key system components and constraints risks.
  - Briefing Note provides summary and detailed analysis on key drivers, loads, system operation, market activity and outcomes of the monthly energy study report. Provides final recommendation on Domestic Threshold Buy / Sell Price based on Energy Study Report.
  - Detailed report on current month forecast, previous month forecast, and latest Board Approved forecast.
- Although water values for the short-term horizon are computed from the Energy Study (ES) process, some users indicated the information provided does not always serve short-term operational needs. The Operations Planning group often relies on a less sophisticated model ("Ultralight model") to seek basin price information for short-term system planning.
  - The results from the Ultralight model are compared against those from the ES models. Interviews revealed that the water values from the Ultralight model often deviate from those obtained by the ES models. Decisions are made through discussions with management and expert assessment.
  - Although the Ultralight model can provide water values within a day, it is not as sophisticated as the ES models.

Energy Studies Process Audit F2019

- Ultralight uses Excel which is a less flexible development environment and does not facilitate a computationally efficient solution process. As well, the implementation and working principle of this model is only known by one person who will be retiring within the year.
- The Ultralight model uses an alternative approach instead of formal optimization which is used in key models within the Energy Studies Process. This approach can speed up the problem solving process, however finding an optimal solution is not guaranteed.

- Using different models with different planning horizons in a hierarchy is common in other hydro dominated systems like Scandinavia and Brazil. However, it appears the Ultralight model is an alternative parallel model that is easier to run, rather than a model for refining the long-terms signals (i.e. water values) from the Energy Study models.

	Recommendations	Management Action Plans
	Outputs	
11	❑ Review the use of the Energy Study results for short-term operational purposes. ❑ Evaluate the Ultralight model, both in terms of its role in scheduling hierarchy, methodology and implementation. ❑ Consider building a more robust operational model for shorter term planning with more formal coupling with the Energy Studies models.	❑ Management will review the process for shorter term modelling.

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Appendix EE

Tariff Sheets

Table of Contents

List of Tables

Section 1 of this appendix describes how the requested rate increase in this Application will be applied to the default tiered rates for BC Hydro's residential and transmission service rate classes in accordance with previously approved Commission pricing principles. The default rates for the other rate classes do not have specific approved pricing principles applicable to them and they have been determined by increasing each component of the rate by the requested rate increase.

BC Hydro's OATT rates are the subject of Chapter 9 of the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (**RRA**) and are not explained in this appendix. Appendix EE provides black-lined and clean copies of the tariff pages with the proposed rates that will be applicable on April 1, 2019.

Section 2 contains the fiscal 2020 rates which are requested to be effective April 1, 2019 on an interim and refundable basis. Table EE-1 of this appendix sets out the rates that will be applicable to each of the Rate Schedules in each rate class for fiscal 2020 and fiscal 2021 and compares them to the fiscal 2019 rates, which were on a final basis as per Commission Order No. G-47-18.

1 Application of Rate Increases

1.1 Residential Rates

1.1.1 Rate Schedules (RS) 1101, 1121 – Residential Service

Rate Schedule 1101 is the Residential Inclining Block (**RIB**) rate, which is the default Residential rate. Rate Schedule 1121 is the RIB rate for Multiple Residential Service. The RIB rate structure is a two-step inclining block rate with the first step called the Step-1 energy rate and the amount above that the Step-2 energy rate. The RIB rate was implemented on October 1, 2008.

On September 24, 2015, BC Hydro filed its 2015 Rate Design Application which requested approval of 'pricing principles' for fiscal 2017 to fiscal 2019 for the RIB rate and that would be effective April 1, 2016. The term “pricing principles” refers to how the revenue requirement rate increases, which are set by the Commission through BC Hydro’s Revenue Requirements Applications, are applied to each of the RIB rate’s pricing elements.

BC Hydro’s proposed RIB Pricing Principles for Rate Schedules 1101 and Rate Schedules 1121 for fiscal 2017 to fiscal 2019 were to uniformly increase the three pricing elements of the RIB rate by the amount of the approved rate increases. These pricing principles were approved by Directive 1 of Commission Order No. G-5-17.

On October 4, 2018, BC Hydro applied to extend these pricing principles to March 31, 2020. The Commission approved the extension of the existing RIB rate pricing principles for fiscal 2020 by Commission Order No. G-214-18.

BC Hydro uses the approved pricing principles to derive the RIB rates shown in Table EE-1 below. As the pricing principles for fiscal 2021 have not yet been determined and will be the subject of a future rate design application prior to the end of fiscal 2021, the current pricing principles have been applied to that year.

To derive fiscal 2020 RIB rates, each of the three components of the RIB rate (Step-1 energy rate, Step-2 energy rate and Basic Charge) are increased by the proposed rate increase of 6.85 per cent. The same approach has been used to derive the fiscal 2021 RIB rates, using the proposed rate increase of 0.72 per cent. The fiscal 2020 rates are requested to apply on an interim basis and if the Commission approves a different rate increase than BC Hydro is applying for in fiscal 2020, BC Hydro will reflect this in final fiscal 2020 rates.

1.2 Transmission Service Rates

1.2.1 Rate Schedule (RS) 1823 – Transmission Service – Stepped Rate

BC Hydro applied for approval of Rate Schedule 1823 Stepped Rate pricing principles for the period fiscal 2017 to fiscal 2019 in its 2015 Rate Design Application. These pricing principles were approved by Directive 9 of Commission Order No. G-5-17.

Under the pricing principles, for fiscal 2017, the Tier 2 rate is set to the lower end of BC Hydro's long run marginal cost of energy and the Tier 1 rate is set to reflect the 4.0 per cent fiscal 2017 rate increase according to the bill neutrality approach i.e., 90 per cent of the Tier 1 rate plus 10 per cent of the Tier 2 rate is equal to the flat rate (Rate Schedule 1827 energy rate or the Rate Schedule 1823 Energy Charge A). Thereafter, in fiscal 2018 and fiscal 2019, the applicable rate increases are applied equally to both Tier 1 and Tier 2 energy rates as per the Commission Order.

On February 15, 2019, BC Hydro applied to extend the current fiscal 2018 and fiscal 2019 RS 1823 Stepped Rate approved pricing principles to the end of fiscal 2021.

The fiscal 2020 Transmission Service stepped rates in Table EE-1 are based on the assumption that the Commission approves BC Hydro's application to extend the pricing principles to the end of fiscal 2021. Therefore, the proposed fiscal 2020 rate increase of 6.85 per cent is applied equally to the RS 1823 Tier 1 energy rate and the Tier 2 energy rate and the same approach has been used to derive the fiscal 2021 rates, using the proposed rate increase of 0.72 per cent.

Other pricing elements (demand charge, energy rate applicable to Rate Schedule 1823 customers that do not have a Customer Baseline Load and monthly minimum charge) will increase by the same applicable RRA rate increase.

2 Summary of Fiscal 2020 and Fiscal 2021 Rates

Table EE-1 provides the rates in each BC Hydro rate schedule for fiscal 2020 and fiscal 2021 and a comparison to the fiscal 2019 rates which are approved on a final basis as per Commission Order No. G-47-18.

Table EE-1 Fiscal 2019 and Fiscal 2020 Rates

Rate Class	Rate Schedule	Rate	F2019 Approved	F2020 Rate Increase 6.85%	F2021 Rate Increase 0.72%
Residential	1101 / 1121	Basic Charge ($/day)	0.1956	0.2090	0.2105
		Step-1 energy rate ($/kWh)	0.0884	0.0945	0.0952
		Step-2 energy rate ($/kWh)	0.1326	0.1417	0.1427
Residential	1105 (closed)[1]	Energy rate ($/kWh)	0.0636	0.0713	0.0790
Residential Zone II	1107 / 1127	Basic Charge ($/day)	0.2086	0.2229	0.2245
		Step-1 energy rate ($/kWh)	0.1059	0.1132	0.1140
		Step-2 energy rate ($/kWh)	0.1820	0.1945	0.1959
Residential	1148 (closed)	Basic Charge ($/day)	0.2086	0.2229	0.2245
		Energy rate $/kWh	0.1059	0.1132	0.1140
Residential	1151 / 1161	Basic Charge ($/day)	0.2086	0.2229	0.2245
		Energy rate $/kWh	0.1059	0.1132	0.1140

[1] For the test period, the proposed rate increases are applied according to the residential E-Plus phase-out design, as approved by BCUC Order No. G-194-17. As such, the rate increases as shown in this table do not directly reflect the applied for rate increases in this application.

Rate Class	Rate Schedule	Rate	F2019 Approved	F2020 Rate Increase 6.85%	F2021 Rate Increase 0.72%
Exempt General Service	1200 / 1201 / 1210 / 1211	Basic Charge ($/day)	0.2502	0.2673	0.2692
		Demand rate - Step-1 ($/kW)	0	0	0
		Demand rate - Step-2 ($/kW)	6.10	6.52	6.57
		Demand rate - Step-3 ($/kW)	11.69	12.49	12.58
		Energy Rate - Tier 1 ($/kWh)	0.1190	0.1272	0.1281
		Energy Rate - Tier 2 ($/kWh)	0.0572	0.0611	0.0615
General Service	1205 / 1206 / 1207 (closed)	Energy Rate - Tier 1 ($/kWh)	0.0579	0.0619	0.0623
		Energy Rate - Tier 2 ($/kWh)	0.0379	0.0405	0.0408
		Energy rate during period of interruption ($/kWh)	0.3367	0.3598	0.3624
Small General Service Zone II	1234	Basic Charge ($/day)	0.2502	0.2673	0,2692
		Energy Rate - Tier 1 ($/kWh)	0.1190	0.1272	0.1281
		Energy Rate - Tier 2 ($/kWh)	0.1981	0.2117	0.2132
Distribution Service	1253	Monthly Minimum energy charge($/month)	45.87	49.01	49.36
Large General Service Zone II	1255 / 1256 / 1265 / 1266	Basic Charge ($/day)	0.2502	0.2673	0.2692
		Energy Rate - Tier 1 ($/kWh)	0.1190	0.1272	0.1281
		Energy Rate - Tier 2 ($/kWh)	0.1981	0.2117	0.2132
Distribution Service	1268	Energy charge ($/kWh)	0.00184	0.00197	0.00198

Rate Class	Rate Schedule	Rate	F2019 Approved	F2020 Rate Increase 6.85%	F2021 Rate Increase 0.72%
Shore Power Service (Distribution)	1280	Administrative Charge ($/month)	150.00	150.00	150.00
		Energy Rate ($/kWh)	0.09836	0.10510	0.10585
Net Metering Service	1289	Energy Rate $/kWh	0.0999	0.0999	0.0999
Small General Service	1300 / 1301 / 1310 /1311	Basic Charge ($/day)	0.3411	0.3645	0.3671
		Energy Rate ($/kWh)	0.1173	0.1253	0.1262
Irrigation	1401	Irrigation season energy rate ($/kWh)	0.0573	0.0612	0.0616
		Non-irrigation season energy rate - Tier 1 ($/kWh)	0.0573	0.0612	0.0616
		Non-irrigation season energy rate - Tier 2 ($/kWh)	0.4541	0.4852	0.4887
		Minimum charge irrigation season $/kW	5.73	6.12	6.16
		Minimum charge non-irrigation season if consumption >500 kWh ($ per kW)	45.80	48.94	49.29
Medium General Service	1500 / 1501 / 1510 / 1511	Basic Charge ($/day)	0.2502	0.2673	0.2692
		Demand rate - all kW ($/kW)	5.07	5.42	5.46
		Energy rate - all kWh ($/kWh)	0.0906	0.0968	0.0975

Rate Class	Rate Schedule	Rate	F2019 Approved	F2020 Rate Increase 6.85%	F2021 Rate Increase 0.72%
Large General Service	1600 / 1601 / 1610 / 1611	Basic Charge ($/day)	0.2502	0.2673	0.2692
		Demand rate – all kW ($/kW)	11.55	12.34	12.43
		Energy rate - all kWh ($/kWh)	0.0567	0.0606	0.0610
Street Lighting	1701	100 SV fixture rate ($/month)	18.34	19.60	19.74
		150 SV fixture ($/month)	21.88	23.38	23.55
		200 SV fixture ($/month)	25.26	26.99	27.18
		175 MV fixture ($/month)	20.16	21.54	21.70
		250 MV fixture ($/month)	23.23	24.82	25.00
		400 MV fixture ($/month)	29.94	31.99	32.22
Street Lighting	1702	Each Unmetered fixture ($/watt per month)	0.0353	0.0377	0.0380
		Each Metered fixture ($/kWh)	0.1059	0.1132	0.1140
Street Lighting	1703	Energy rate ($/watt per month)	0.0353	0.0377	0.0380
		Contact rate ($/contact per month)	1.06	1.13	1.14
Street Lighting	1704	Energy rate $/kWh	0.1059	0.1132	0.1140

Rate Class	Rate Schedule	Rate	F2019 Approved	F2020 Rate Increase 6.85%	F2021 Rate Increase 0.72%
Street Lighting	1755 (closed)	Pole owned by Customer			
		175 MV or 100 SV fixture charge ($ per month)	17.19	18.37	18.50
		400 MV or 150 SV fixture charge ($ per month)	29.63	31.66	31.89
		Pole on public property			
		175 MV or 100 SV fixture charge ($ per month)	18.26	19.51	19.65
		400 MV or 150 SV fixture charge ($ per month)	30.71	32.81	33.05
		Pole paid by BC Hydro			
		175 MV or 100 SV fixture charge ($ per month)	22.48	24.02	24.19
		400 MV or 150 SV fixture charge ($ per month)	35.39	37.81	38.08
Transmission Service	1823	Demand rate ($/kVA)	8.139	8.697	8.760
		Energy rate A ($/kWh)	0.04771	0.05098	0.05135
		Energy rate B - Tier 1 ($/kWh)	0.04244	0.04535	0.04568
		Energy rate B - Tier 2 ($/kWh)	0.09509	0.10160	0.10233
		Minimum demand ($/kVA)	8.139	8.697	8.7600

Rate Class	Rate Schedule	Rate	F2019 Approved	F2020 Rate Increase 6.85%	F2021 Rate Increase 0.72%
Transmission Service	1825	Demand rate ($/kVA)	8.139	8.697	8.7600
		Winter HLH energy rate (below 90%) ($/kWh)	0.04244	0.04535	0.04568
		Winter HLH energy rate (above 90%) ($/kWh)	0.10611	0.11337	0.11418
		Winter LLH energy rate (below 90%) ($/kWh)	0.04244	0.04535	0.04568
		Winter LLH energy rate (above 90%) ($/kWh)	0.09616	0.10275	0.10349
		Spring energy rate (below 90%) ($/kWh)	0.04244	0.04535	0.04568
		Spring energy rate (above 90%) ($/kWh)	0.08565	0.09151	0.09217
		Remaining energy rate (below 90%) ($/kWh)	0.04244	0.04535	0.04568
		Remaining energy rate (above 90%) ($/kWh)	0.09392	0.10035	0.10107
Transmission Service	1827	Demand rate ($/kVA)	8.139	8.697	8.76
		Energy rate ($/kWh)	0.04771	0.05098	0.05135
		Minimum demand ($/kVA)	8.139	8.697	8.76
Transmission Service	1852	Excess Demand rate ($/kVA)	8.139	8.697	8.76
Transmission Service	1853	Minimum Monthly Charge ($/month)	45.87	49.01	49.36

Rate Class	Rate Schedule	Rate	F2019 Approved	F2020 Rate Increase 6.85%	F2021 Rate Increase 0.72%
Transmission Service	1880	Administrative Charge per Period of Use ($)	150.00	150.00	150.00
		Energy Rate ($/kWh)	0.09509	0.10160	0.10233
Shore Power Service (Transmission)	1891	Administrative Charge ($/month)	150.00	150.00	150.00
		Energy Rate ($/kWh)	0.09509	0.10160	0.10233
Transmission Service FortisBC	3808	Demand rate ($/kW)	8.139	8.697	8.760
		Energy rate - tranche 1 ($/kWh)	0.04771	0.05098	0.05135
		Energy rate – tranche 2 ($/kWh)[2]	0.09509	0.09509	0.09509
Deferral Account Rate Rider	1901	Per cent	5	No applicable charge	No applicable charge

[2] BC Hydro has not changed tranche 2 rate of Rate Schedule 3808 pricing over the test period. Any changes to the tranche 2 rate would be subject to separate application.

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Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix EE

Attachment 1

Tariff Sheets
Clean

1. RESIDENTIAL SERVICE

RATE SCHEDULES 1101, 1121 – RESIDENTIAL SERVICE

Availability	For Residential Service. Service is normally single phase, 60 hertz at the Secondary Voltage available. In BC Hydro's discretion, Service may be three phase 120/208 or 240 volts.
Applicable in	Rate Zone I.
Rate	1. Rate Schedule 1101 – Residential Service: **Basic Charge:** 20.90 ¢ per day plus **Energy Charge:** (a) For Customers billed monthly: Step 1: First 675 kWh per month@ 9.45 ¢/kWh Step 2: Additional kWh per month@ 14.17 ¢/kWh (b) For Customers billed bi-monthly: Step 1: First 1350 kWh per two months@ 9.45 ¢/kWh Step 2: Additional kWh per two months@ 14.17 ¢/kWh Note: For billing purposes, Step 1 is pro-rated on a daily basis. **Minimum Charge:** The Basic Charge

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	2. Rate Schedule 1121 – Multiple Residential Service: **Basic Charge:** 20.90 ¢ per Dwelling per day plus **Energy Charge:** Per Dwelling (a) For Customers billed monthly: Step 1: First 675 kWh. per month@ 9.45 ¢/kWh Step 2: Additional kWh per month@ 14.17 ¢/kWh (b) For Customers billed bi-monthly: Step 1: First 1350 kWh per two months@ 9.45 ¢/kWh Step 2: Additional kWh per two months@ 14.17 ¢/kWh Note: For billing purposes, Step 1 is pro-rated on a daily basis. **Minimum Charge:** The Basic Charge per Dwelling
Discount for Ownership of Transformers	A discount of 25 ¢ per month per kW of Maximum Demand will be applied to amounts owing under Rate Schedule 1121 if the Customer supplies Transformation. BC Hydro will install Metering Equipment with both Demand and Energy measurement capability at the Secondary Voltage.
Special Conditions	1. The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under these Rate Schedules must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission. 2. Rate Schedule 1121 applies if the Premises contains more than two Dwellings.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.

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Rate Increase	Effective April 1, 2019 the rates under these Rate Schedules include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

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1. RESIDENTIAL SERVICE

RATE SCHEDULE 1105 – RESIDENTIAL SERVICE – DUAL FUEL (CLOSED)

Availability	For residential space heating and water heating. Electricity purchased under this Rate Schedule will be separately metered. Service is single phase, 60 hertz, at 120/240 or 240 volts. This Rate Schedule is available only for Premises served under this Rate Schedule on January 15, 1990 and continuously thereafter and only in Premises where there has been no change in Customer since April 1, 2008.
Applicable in	Rate Zone I in areas where and when, in BC Hydro's opinion, BC Hydro's transmission, sub-transmission and distribution circuit feeders are or will be capable of handling the load.
Rate	**Energy Charge:** 7.13 ¢ per kWh
Special Conditions	1. Service under this Rate Schedule is not available to any Premises where Service was previously supplied and Terminated. 2. BC Hydro will upgrade an existing Service Connection supplying firm load to serve additional load in accordance with the Electric Tariff, however, no new or additional load is permitted under this Rate Schedule at any time. All unauthorized consumption of Electricity as estimated by BC Hydro will be billed at the rate for Electricity on the appropriate default Residential Service Rate Schedule. 3. The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under this Rate Schedule must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission.

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Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	The rate under this Rate Schedule is set in accordance with BCUC Order No. G-194-17. Effective April 1, 2019, an interim rate increase of 6.85%, approved by BCUC Order No. , is applied.

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1. RESIDENTIAL SERVICE

RATE SCHEDULES 1107, 1127 – RESIDENTIAL SERVICE – ZONE II

Availability	For Residential Service. Service is normally single phase, 60 hertz at the Secondary Voltage available. In BC Hydro's discretion, Service may be three phase 120/208 or 240 volts.
Applicable in	Rate Zone II.
Rate	1. Rate Schedule 1107 – Residential Service: **Basic Charge:** 22.29 ¢ per day plus **Energy Charge:** First 1500 kWh per month @ 11.32 ¢ per kWh All additional kWh per month @ 19.45 ¢ per kWh **Minimum Charge:** The Basic Charge 2. Rate Schedule 1127 – Multiple Residential Service: **Basic Charge:** 22.29 ¢ per Dwelling per day plus **Energy Charge:** First 1500 kWh per Dwelling per month @ 11.32 ¢ per kWh All additional kWh per month @ 19.45 ¢ per kWh **Minimum Charge:** The Basic Charge per Dwelling
Discount for Ownership of Transformers	A discount of 25 ¢ per month per kW of Maximum Demand will be applied to amounts owing under Rate Schedule 1127 if the Customer supplies Transformation. BC Hydro will install Metering Equipment with both Demand and Energy measurement capability at the Secondary Voltage.

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Special Conditions	1. The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under these Rate Schedules must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission. 2. Rate Schedule 1127 applies if the Premises contains more than two Dwellings.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2019 the rates under these Rate Schedules include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

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1. RESIDENTIAL SERVICE

RATE SCHEDULE 1148 – RESIDENTIAL SERVICE – ZONE II (CLOSED)

Availability	For Residential Service in Rate Zone II where a permanent electric space heating system is in use, providing such system was installed prior to October 10, 1966. This Rate Schedule is available only to a Customer and Premises served under this Rate Schedule on April 24, 1992 and continuously thereafter.
Applicable in	Rate Zone II.
Rate	**Basic Charge:** 22.29 ¢ per day plus **Energy Charge:** 11.32 ¢ per kWh **Minimum Charge:** The Basic Charge
Special Conditions	The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under this Rate Schedule must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019 the rates under this Rate Schedule include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

1. RESIDENTIAL SERVICE

RATE SCHEDULES 1151, 1161 – EXEMPT RESIDENTIAL SERVICE

Availability	For Residential Service and uses exempted from Rate Schedules 1101 and 1121 (Residential Service), including: 1. Use on farms as set out in the definition of Residential Service in the Terms and Conditions; and 2. Use in Rate Zone IB. Service is normally single phase, 60 hertz at the Secondary Voltage available. In BC Hydro's discretion, Service may be three phase 120/208 or 240 volts.
Applicable in	Rate Zone I and Rate Zone IB.
Rate	1. Rate Schedule 1151 – Residential Service: **Basic Charge:** 22.29 ¢ per day plus **Energy Charge:** 11.32 ¢ per kWh **Minimum Charge:** The Basic Charge 2. Rate Schedule 1161 – Multiple Residential Service: **Basic Charge:** 22.29 ¢ per day per Dwelling per day plus **Energy Charge:** 11.32 ¢ per kWh **Minimum Charge:** The Basic Charge per Dwelling

Discount for Ownership of Transformers	A discount of 25 ¢ per month per kW of Maximum Demand will be applied to amounts owing under Rate Schedule 1161 if the Customer supplies Transformation. BC Hydro will install Metering Equipment with both Demand and Energy measurement capability at the Secondary Voltage.
Special Conditions	The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under these Rate Schedules must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2019 the rates under these Rate Schedules include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

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2. GENERAL SERVICE

RATE SCHEDULES 1200, 1201, 1210, 1211 – EXEMPT GENERAL SERVICE (35 KW AND OVER)

Availability	For Customers who qualify for General Service where supply is 60 hertz, single or three phase at Secondary or Primary Voltage and Billing Demand is 35 kW or more. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone IB.
Rate	**Basic Charge:** 26.73 ¢ per day plus **Demand Charge:** First 35 kW of Billing Demand per Billing Period @ $0.00 per kW Next 115 kW of Billing Demand per Billing Period @ $6.52 per kW All additional kW of Billing Demand per Billing Period @ $12.49 per kW plus **Energy Charge:** First 14800 kWh of Energy consumption in the Billing Period @ 12.72 ¢ per kWh All additional kWh of Energy consumption in the Billing Period @ 6.11 ¢ per kWh

Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per Billing Period per kW of Billing Demand will be applied to the above charges if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.
Monthly Minimum Charge	50% of the highest Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding 11 Billing Periods. For the purpose of this provision an on-peak period commences on November 1 in any year and terminates on March 31 of the following year.
Rate Schedules	1. Rate Schedule 1200: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1201: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1210: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1211: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.

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Definitions	Billing Demand is the Maximum Demand in the Billing Period, subject to Special Condition No. 1. Billing Period means a month between regular meter readings, provided that in cases where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period.
Special Conditions	1. Metering Equipment with both Demand and Energy measurement capability will normally be installed. Until such Metering Equipment is installed, or if the installed Metering Equipment does not have Demand measurement capability, Billing Demand will be as estimated by BC Hydro. 2. Migration rule: Customers taking Service under these Rate Schedules will be moved to Service under Rate Schedule 1300, 1301, 1310 or 1311 (Small General Service) if Billing Demand in each of the last 12 consecutive Billing Periods was less than 35 kW.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2019 the rates under these Rate Schedules include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

ACCEPTED:

ORDER NO.

COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULES 1205, 1206, 1207 – GENERAL SERVICE – DUAL FUEL (CLOSED)

Availability	For general space heating, water heating and industrial process heating on an interruptible basis. Electricity purchased under these Rate Schedules will be separately metered. Service is 60 hertz single or three phase at the Secondary or Primary Voltage available. BC Hydro reserves the right to determine the voltage of the Service Connection. These Rate Schedules are available only for Premises served under these Rate Schedules on January 15, 1990 and continuously thereafter, only with respect to equipment served under these Rate Schedules on January 15, 1990 and continuously thereafter, and only in Premises where there has been no change in Customer since April 1, 2008.
Applicable in	Rate Zone I in areas where, in BC Hydro's opinion, BC Hydro's transmission, sub-transmission and distribution circuit feeders are or will be capable of handling the load.
Rate	Except as stated hereunder the rate will be: **Energy Charge:** First 8000 kWh per month @ 6.19 ¢ per kWh All additional kWh per month @ 4.05 ¢ per kWh Exception: If during a Period of Interruption a Customer fails to comply with BC Hydro’s requirement to cease the use of Electricity and BC Hydro, in its sole discretion, continues to supply Electricity, the rate for such Electricity will be: **Energy Charge:** 35.98 ¢ per kWh

ACCEPTED:______________________

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Period of Interruption	A period during which a Customer is required by BC Hydro to cease the use of Electricity under these Rate Schedules.
Rate Schedules	1. Rate Schedule 1205 – Small Commercial Applications: Applies to a Customer whose interruptible heating load is mostly in support of a commercial activity and whose firm Electricity is billed on a General Service (under 35 kW) Rate Schedule. 2. Rate Schedule 1206 – Large Commercial Applications: Applies to a Customer whose interruptible heating load is mostly in support of a commercial activity and whose firm Electricity is billed on a General Service (35 kW and over) Rate Schedule. 3. Rate Schedule 1207 – Industrial Applications: Applies to a Customer whose interruptible heating load is mostly in support of an industrial activity and whose firm Electricity is billed on a General Service Rate Schedule or for farm use on a Residential Rate Schedule.
Special Conditions	1. BC Hydro may, at any time and from time to time, interrupt the supply of Electricity under these Rate Schedules whenever there is a lack of surplus hydro energy and Service cannot be provided economically from other energy sources.

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	2. A Customer taking Service under these Rate Schedules is required to have, to BC Hydro's satisfaction, an installed permanent backup heating system using an alternative fuel, or an installed permanent independent electrical generating system, in good working order, and an adequate supply of fuel therefor, so that the Customer can continue heating operations when the supply of Electricity is interrupted. The output rating of the backup system must be of sufficient capacity to supply the heating load served under these Rate Schedules. If at any time a Customer fails to comply with the foregoing requirements, BC Hydro may immediately Terminate the supply of Electricity under these Rate Schedules to such Customer. 3. BC Hydro will interrupt the supply of Electricity by either manual or automatic means or by written notice by registered mail or hand delivery to the Customer to cease the use of Electricity under these Rate Schedules. A Customer who has been given such written notice to cease the use of Electricity under these Rate Schedules will in accordance with the requirements of the notice cease such use and will not begin to use Electricity again until so authorized by BC Hydro, by written notice. If a Customer fails to comply with these requirements, BC Hydro may in its sole discretion: (a) Continue to supply Electricity, in which case the rate will be the rate for Electricity during a Period of Interruption as stated in these Rate Schedules, or (b) Terminate the supply of Electricity under these Rate Schedules.

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	4. The initial contract period for dual fuel interruptible Service under these Rate Schedules is: (a) One year where no new facility is required to be constructed or the only facility required to be constructed by BC Hydro to serve the Customer is a drop Service Connection, or (b) Two years where more than a drop Service Connection is required to be constructed by BC Hydro to serve the Customer. At the expiration of a contract period, the contract period is automatically extended from year to year unless either the Customer or BC Hydro gives written notice to the other 30 days prior to the anniversary date. Transfer of the load served under these Rate Schedules to a general firm Rate Schedule will not be permitted during a Period of Interruption. 5. These Rate Schedules are not available to Premises where Electricity under it was previously supplied and Terminated. 6. BC Hydro will upgrade an existing Service Connection supplying firm load to serve additional load under these Rate Schedules. The charge for upgrading will be the same as applicable to a new Service Connection. 7. For existing Customers adding load to take Service under these Rate Schedules, and where an overhead distribution Extension is required to accommodate such added load BC Hydro will contribute toward the estimate cost of the Extension an amount not exceeding two times the annual revenue as estimated by BC Hydro to be received by the applicant. Any excess cost will be contributed by the applicant.

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8. No other load than that stipulated in the Availability clause is permitted under these Rate Schedules. Any unauthorized use of Electricity or any refusal by a Customer to permit access to Premises in accordance with the Terms and Conditions of BC Hydro's Electric Tariff will result in immediate Termination under the applicable Rate Schedule and all unauthorized consumption as estimated by BC Hydro will be billed at the rate for Electricity during a Period of Interruption as stated in these Rate Schedules.

9. In addition to and without restriction of any other limitations of liability of BC Hydro, BC Hydro will specifically not be liable for any loss, damage, injury or expense occasioned to or suffered by any Customer receiving Service on these Rate Schedules, or by any other Person, for or by reason of any interruption of Electricity supply whatsoever for any reason whatsoever.

10. A Customer who signs a contract with BC Hydro for the supply of Electricity to new load under these Rate Schedules during the period commencing July 1, 1988 and ending December 31, 1988 will be eligible to receive an incentive rebate on his Electricity bills provided the Customer begins taking Service under these Rate Schedules no later than 12 months following the date the contract was signed.

11. A rebate will be applied to reduce the effective rate to 1.1 ¢ per kWh. Such rebate will apply only to an accumulated maximum of $30.00 per kW of connected new load in excess of 35 kW and only up to the first two years following connection. Bills for Energy consumed will be calculated and presented at full rates with the rebate for any given period applied to the following bill. The maximum two year period of billing rebates will be extended by the equivalent of any Period of Interruption. Rebates will not be applied to reduce the rate applicable for consumption during a Period of Interruption, nor will rebates be applied to reduce Power Factor surcharges.

	12. At the conclusion of any Period of Interruption, BC Hydro may Terminate Service under these Rate Schedules to any Customer who used Electricity during a Period of Interruption, unless it can be demonstrated to BC Hydro's satisfaction that adequate standby facilities exist.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2019 the rates under these Rate Schedules include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

ACCEPTED:

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COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULE 1234 – SMALL GENERAL SERVICE (UNDER 35 KW) – ZONE II

Availability	For all purposes where a meter with Demand measurement capability is not installed because the Customer's Demand as estimated by BC Hydro is less than 35 kW. Supply is 60 hertz, single or three phase at an available Secondary Voltage.
Applicable in	Rate Zone II.
Rate	**Basic Charge:** 26.73 ¢ per day plus **Energy Charge:** First 7000 kWh per month @ 12.72 ¢ per kWh All additional kWh per month @ 21.17 ¢ per kWh **Minimum Charge:** The Basic Charge
Special Conditions	Special Conditions for Unmetered Service: 1. BC Hydro may permit unmetered Service under this Rate Schedule if it can estimate to its satisfaction the Energy used in kilowatt hours over a period of two months based on the connected load and the hours of use. 2. The Customer, if required by BC Hydro, will provide and maintain such controls, including timing devices, as BC Hydro considers necessary, and facilities satisfactory to BC Hydro for the maintenance of such controls. 3. The hours of use per period will be as specified by the Customer or as estimated by BC Hydro, whichever is greater.

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4. The Customer will supply, install and maintain all wiring, fixtures, control devices and equipment, including the controls and devices described in Special Condition No. 2, at the expense of the Customer.

5. All wiring, fixtures, control devices and equipment and the method of installing, operating and maintaining the same are subject to the approval of BC Hydro which approval may be withdrawn by BC Hydro, at any time, at BC Hydro's sole discretion.

6. The Customer will notify BC Hydro immediately of any proposed or actual change in load, load characteristics, or hours of use.

7. BC Hydro may at any time, in its sole discretion, install Metering Equipment, and thereafter bill the Customer on the appropriate Rate Schedule as a metered account.

8. For display signs and signboard lighting, where hours of use are controlled by timing devices, the following turn-on times will apply, unless BC Hydro otherwise agrees in writing:

Period	Turn-on Time
January 1 to January 15:	4:00 p.m.
January 16 to February 28:	4:30 p.m.
March 1 to April 30:	6:30 p.m.
May 1 to August 15:	8:30 p.m.
August 16 to September 30:	6:30 p.m.
October 1 to November 15:	4:30 p.m.
November 16 to December 31:	4:00 p.m.

	9. In all cases, where hours of use of display signs or signboard lighting commence at dusk and are controlled either by timing devices or by photo-electric cells, the following hours of use for a period of two months will be deemed for billing purposes: Dusk to 10 p.m.: 216 hours Dusk to 11 p.m.: 270 hours Dusk to 12 p.m.: 330 hours Dusk to 1 a.m.: 380 hours Dusk to Dawn: 666 hours (All times are Pacific Time.)
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019 the rates under this Rate Schedule include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

2. GENERAL SERVICE

RATE SCHEDULE 1253 – DISTRIBUTION SERVICE – IPP STATION SERVICE

Availability	For Customers who are Independent Power Producers (**IPPs**) served at distribution voltage, on an interruptible basis.
Applicable in	Rate Zone I excluding Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Energy Charge:** The sum, over the billing period, of the hourly Energy consumed multiplied by the entry in the Intercontinental Exchange (**ICE**) Mid Columbia (Mid-C) Peak, and Mid-C Off-Peak weighted average index price as published by the ICE in the ICE Day Ahead Power Price Report that corresponds to the time when consumption occurred, during that hour.
Monthly Minimum Charge	$49.01
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. 2. BC Hydro may, without notice to the Customer, refuse to supply or terminate the supply of Electricity under this Rate Schedule if at any time BC Hydro does not have sufficient energy or capacity. 3. Prior to taking Electricity under this Rate Schedule, the Customer may be required to obtain approval from BC Hydro. BC Hydro will advise the Customer of the need to obtain approval prior to the taking of Electricity under this Rate Schedule. 4. Electricity taken under this Rate Schedule is to be used solely for maintenance and black-start requirements and will not displace electricity that would normally be generated by the Customer.

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Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019 the Monthly Minimum Charge under this Rate Schedule includes an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

2. GENERAL SERVICE

RATE SCHEDULES 1255, 1256, 1265, 1266 – GENERAL SERVICE (35 KW AND OVER) – ZONE II

Availability	For all purposes. Supply is 60 hertz, single or three phase at Secondary or Primary Voltage. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone II.
Rate	**Basic Charge:** 26.73 ¢ per day plus **Energy Charge:** First 200 kWh per kW of Billing Demand per month @ 12.72 ¢ per kWh All additional kWh per month @ 21.17 ¢ per kWh
Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per month per kW of Billing Demand will be applied to the above rate if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts the discount for metering at a Primary Voltage will be applied first.
Monthly Minimum Charge	The monthly minimum charge to be paid by a Customer on Rate Schedule 1255, 1256, 1265 or 1266, as applicable, will be the charge the Customer would have been billed under Rate Schedule 1200, 1201, 1210 or 1211 (Exempt General Service – 35 kW and over), respectively.
Rate Schedules	1. Rate Schedule 1255: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation.

	2. Rate Schedule 1256: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1265: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1266: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Special Conditions	1. Metering Equipment with both Demand and Energy measurement capability will normally be installed. Until such Metering Equipment is installed, or if the installed Metering Equipment does not have Demand measurement capability, Billing Demand will be as estimated by BC Hydro. 2. Where the Customer’s Demand is or is likely to be in excess of 45 kVA, BC Hydro may require such Customer to execute a special contract for Service, including such special conditions as BC Hydro, in its sole discretion considers necessary.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2019 the rates under these Rate Schedules include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. ______.

2. GENERAL SERVICE

RATE SCHEDULE 1268 – DISTRIBUTION SERVICE – IPP DISTRIBUTION TRANSPORTATION ACCESS

Availability	For Customers who have generators connected to BC Hydro's distribution system and who want to access BC Hydro's transmission system pursuant to and in accordance with BC Hydro's Open Access Transmission Tariff (OATT).
Applicable in	Rate Zone I excluding Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Distribution Transportation Charge:** 0.197 ¢ per kWh
Special Conditions	1. The Customer is required to pay the costs, including the cost of altering existing facilities, to connect the generator to BC Hydro's distribution system in accordance with BC Hydro's Connection Requirements for Utility or Non-Utility Generation, 35 kV and Below. 2. For Customers with self-generation (i.e., with a Customer Baseline Load (**CBL**) greater than zero), this Rate Schedule is only applicable to sales of Surplus Energy. It may not be used by self-generating Customers who appear to have varied their demand for power from BC Hydro based on the actual or anticipated difference between BC Hydro's rate for providing Service to them and the market price of power. 3. For the purposes of this Rate Schedule, "Surplus Energy" in any period is the energy made available from generation by the Customer calculated as the difference between the Customer's CBL and the Customer's actual consumption from BC Hydro in that period.

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	4. The Customer's CBL is established, in general, by determining the Customer's Energy consumption, on a monthly basis, for the past three years; in cases where inadequate history exists, alternative methods may be used to determine a Customer's CBL. Once established, the Customer's CBL will not be automatically adjusted for changes in the Customer's net metered consumption from BC Hydro. Any subsequent changes to the CBL must be due to changes in the Customer's load and not due to changes in its generation. The Customer must provide metered output from its generator which demonstrates an increase in generation output commensurate in time and amount with the Surplus Energy transported using this Rate Schedule. Where it appears that the Customer has transported on this Rate Schedule Energy that is not Surplus Energy, BC Hydro will provide replacement energy to the Customer's load at market prices, subject to Commission approval for such sales. 5. The metering point to determine the electricity being delivered to BC Hydro's distribution system will be determined by BC Hydro. The electricity delivered to BC Hydro's distribution system will also be deemed to be delivered to BC Hydro's transmission system (that is, no distribution loss adjustment will be applied to the electricity from an independent power producer or self-generator when determining capacity and energy delivered to BC Hydro's transmission system).
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019 the rate under this Rate Schedule includes an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

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2. GENERAL SERVICE

RATE SCHEDULE 1280 – SHORE POWER SERVICE (DISTRIBUTION)

Availability	For the supply of Shore Power to Port Customers who qualify for General Service for use by Eligible Vessels while docked at the Port Customer's Port Facility, on an interruptible basis. Shore Power Service is supplied at 60 Hz, three phase at Primary Voltage.
Applicable in	Rate Zone I.
Rate	**Administrative Charge:** \$150.00 per month plus **Energy Charge:** 10.510 ¢ per kWh
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. BC Hydro may refuse or Terminate Service under this Rate Schedule in circumstances where BC Hydro does not have sufficient energy or capacity. For greater certainty, BC Hydro will not be required to construct an Extension for the purpose of increasing the capacity of BC Hydro's distribution system to provide Shore Power Service under this Rate Schedule. 2. The terms and conditions under which Shore Power Service is supplied are contained in the Shore Power Service Agreement (Electric Tariff Supplement No. 86). The Port Customer will pay to BC Hydro the charges set out in this Rate Schedule in addition to any charges set out in the Shore Power Service Agreement. 3. A Port Customer that provides Port Electricity at a Port Facility under Rate Schedules 1600, 1601, 1610, 1611 or 1823 is not eligible to take Shore Power Service under this Rate Schedule to provide Port Electricity to that Port Facility, or any Port Facility served by the same BC Hydro delivery facilities.

ACCEPTED:______________________________

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	4. On each occasion, if any, that BC Hydro is required to dispatch power line technicians or other workers to operate the switchgear for each connect and disconnect of Eligible Vessels docked at the Port Customer's Port Facility, BC Hydro will charge, and the Port Customer will pay, the reasonable time and labour costs for this service. The charge will be based on prevailing BC Hydro contracted labour rates and will be separately itemized on the Port Customer's monthly bill.
Definitions	For purposes of this Rate Schedule, capitalized terms have the meanings given to them in Electric Tariff Supplement No. 86.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

2. GENERAL SERVICE

RATE SCHEDULES 1300, 1301, 1310, 1311 – SMALL GENERAL SERVICE (UNDER 35 KW)

Availability	For Customers who qualify for General Service and whose Demand, metered or estimated by BC Hydro, as applicable, is less than 35 kW. Supply is 60 hertz, single or three phase at a Secondary or Primary Voltage.
Applicable in	Rate Zone I and Rate Zone IB.
Rate	**Basic Charge:** 36.45 ¢ per day plus **Energy Charge:** 12.53 ¢ per kWh **Minimum Charge:** The Basic Charge
Discounts	1. A discount of 1½% will be applied to the above charges if Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per month per kW of Demand will be applied if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.
Rate Schedules	1. Rate Schedule 1300: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1301: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation.

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	3. Rate Schedule 1310: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1311: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Special Conditions	Special Conditions for Unmetered Service: 1. BC Hydro may permit unmetered Service under these Rate Schedules if it can estimate to its satisfaction the Energy used in kilowatt hours over a period of two months based on the connected load and the hours of use. 2. The Customer, if required by BC Hydro, will provide and maintain such controls, including timing devices, as BC Hydro considers necessary, and facilities satisfactory to BC Hydro for the maintenance of such controls. 3. The hours of use per period will be as specified by the Customer, or as estimated by BC Hydro, whichever is greater. 4. The Customer will supply, install and maintain all wiring, fixtures, control devices and equipment, including the controls and devices described in Special Condition No. 2, at the expense of the Customer. 5. All wiring, fixtures, control devices and equipment and the method of installing, operating and maintaining the same are subject to the approval of BC Hydro which approval may be withdrawn by BC Hydro, at any time, at BC Hydro's sole discretion. 6. The Customer will notify BC Hydro immediately of any proposed or actual change in load, load characteristics, or hours of use.

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7. BC Hydro may at any time, in its sole discretion, install Metering Equipment, and thereafter bill the Customer on the appropriate Rate Schedule as a metered account.

8. For display signs and signboard lighting, where hours of use are controlled by timing devices, the following turn-on times will apply, unless BC Hydro otherwise agrees in writing:

Period	Turn-on Time
January 1 to January 15:	4:00 p.m.
January 16 to February 28:	4:30 p.m.
March 1 to April 30:	6:30 p.m.
May 1 to August 15:	8:30 p.m.
August 16 to September 30:	6:30 p.m.
October 1 to November 15:	4:30 p.m.
November 16 to December 31:	4:00 p.m.

9. In all cases, where hours of use of display signs or signboard lighting commence at dusk and are controlled either by timing devices or by photo-electric cells, the following hours of use for a period of two months will be deemed for billing purposes:

Dusk to 10 p.m.:	216 hours
Dusk to 11 p.m.:	270 hours
Dusk to 12 p.m.:	330 hours
Dusk to 1 a.m.:	380 hours
Dusk to Dawn:	666 hours

(All times are Pacific Time.)

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	Migration Rules: 1. Migration rules from Small General Service: Customers taking Service under these Rate Schedules will be moved to Service: (a) Under Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) if Demand in half of the last six bi-monthly billing periods or half of the last 12 monthly billing periods (as applicable) was 35 kW or more, but less than 150 kW. (b) Under Rate Schedules 1600, 1601, 1610 or 1611 (Large General Service) if Demand in half of the last six bi-monthly billing periods or half of the last 12 monthly billing periods (as applicable) was 150 kW or more, or if total Energy consumption in any 12 consecutive month period exceeded 550,000 kWh. 2. Migration rules to Small General Service: Customers will be moved to Service under these Rate Schedules (Small General Service) from Rate Schedules 1600, 1601, 1610 or 1611 (Large General Service) or Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) if Billing Demand in each of the last 12 billing periods was less than 35 kW.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2019 the rates under these Rate Schedules include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

2. GENERAL SERVICE

RATE SCHEDULES 1500, 1501, 1510, 1511 – MEDIUM GENERAL SERVICE (35 KW OR GREATER AND LESS THAN 150 KW)

Availability	For Customers who qualify for General Service and whose Billing Demand is equal to or greater than 35 kW but less than 150 kW, and whose Energy consumption in any 12-month period is equal to or less than 550,000 kWh. Supply is 60 hertz, single or three phase at Secondary or Primary Voltage. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone I.
Rate	**Basic Charge:** 26.73 ¢ per day plus **Demand Charge:** $5.42 per kW of Billing Demand plus **Energy Charge:** 9.68 ¢ per kWh
Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per Billing Period per kW of Billing Demand will be applied to the above charges if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.

Monthly Minimum Charge	50% of the highest Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding 11 Billing Periods. For the purpose of this provision an on-peak period commences on November 1 in any year and terminates on March 31 of the following year.
Rate Schedules	1. Rate Schedule 1500: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1501: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1510: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1511: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Definitions	1. Billing Demand The Billing Demand will be the highest kW Demand in the Billing Period. 2. Billing Period A month between regular meter readings, provided that in cases where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period.

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Special Conditions	1. Metering Metering Equipment with both Demand and Energy measurement capability will normally be installed. Until such Metering Equipment is installed, or if the installed Metering Equipment does not have Demand measurement capability, Billing Demand will be as estimated by BC Hydro 2. Migration Rules 2.1. Migration rules from Medium General Service: Customers taking Service under these Rate Schedules (Medium General Service) will be moved to Service: (a) Under Rate Schedules 1300, 1301, 1310 or 1311 (Small General Service) if Billing Demand in each of the last 12 consecutive Billing Periods was less than 35 kW. (b) Under Rate Schedules 1600, 1601, 1610 or 1611 (Large General Service) if Billing Demand in half of the last 12 Billing Periods was 150 kW or more, or if total Energy consumption in any 12 consecutive month period exceeded 550,000 kWh.

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	2.2. Migration rules to Medium General Service: Customers will be moved to Service under these Rate Schedules (Medium General Service): (a) From Rate Schedules 1600, 1601, 1610 or 1611 (Large General Service) if Billing Demand in each of the last 12 Billing Periods was 35 kW or more, but less than 100 kW, and Energy consumption during the same period was less than 400,000 kWh. (b) From Rate Schedules 1300, 1301, 1310 or 1311 (Small General Service) if Billing Demand in half of the last six bi-monthly Billing Periods or half of the last 12 monthly Billing Periods (as applicable) was 35 kW or more, but less than 150 kW, and total Energy consumption in the same period was less than 550,000 kWh.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2019 the rates under these Rate Schedules include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

2. GENERAL SERVICE

RATE SCHEDULES 1600, 1601, 1610, 1611 – LARGE GENERAL SERVICE (150 KW AND OVER)

Availability	For Customers who qualify for General Service and whose Billing Demand is equal to or greater than 150 kW, or whose Energy consumption in any 12 month period is greater than 550,000 kWh. Supply is 60 hertz, single or three phase at Secondary or Primary Voltage. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone I.
Rate	**Basic Charge:** 26.73 ¢ per day plus **Demand Charge:** $12.34 per kW of Billing Demand plus **Energy Charge:** 6.06 ¢ per kWh
Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per Billing Period per kW of Billing Demand will be applied to the above charges if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.

Monthly Minimum Charge	50% of the highest Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding 11 Billing Periods. For the purpose of this provision an on-peak period commences on November 1 in any year and terminates on March 31 of the following year.
Rate Schedules	1. Rate Schedule 1600: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1601: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1610: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1611: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Definitions	1. Billing Demand The Billing Demand will be the highest kW Demand in the Billing Period. 2. Billing Period A month between regular meter readings, provided that where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period.

<table>
<tr><td>Special Conditions</td><td>
1. Metering
Metering Equipment with both Demand and Energy measurement capability will normally be installed. Until such Metering Equipment is installed, or if the installed Metering Equipment does not have Demand measurement capability, Billing Demand will be as estimated by BC Hydro.
2. Migration Rules
2.1. Migration rules from Large General Service: Customers taking Service under these Rate Schedules (Large General Service) will be moved to Service:
(a) Under Rate Schedules 1300, 1301, 1310 or 1311 (Small General Service) if Billing Demand in each of the last 12 consecutive Billing Periods was less than 35 kW.
(b) Under Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) if Billing Demand in each of the last 12 consecutive Billing Periods was 35 kW or more but less than 100 kW, and Energy consumption in the same period was less than 400,000 kWh.
2.2. Migration rules to Large General Service: Customers will be moved to Service under these Rate Schedules (Large General Service) from Rate Schedules 1300, 1301, 1310 or 1311 (Small General Service) or Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) if Billing Demand in half of the last six bi-monthly Billing Periods or half of the last 12 monthly Billing Periods (as applicable) was 150 kW or more, or if total Energy consumption in any 12 consecutive month period exceeded 550,000 kWh.
</td></tr>
<tr><td>Rate Rider</td><td>The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.</td></tr>
</table>

ACCEPTED:______________________

ORDER NO.______________________

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COMMISSION SECRETARY

Rate Increase	Effective April 1, 2019 the rates under these Rate Schedules include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

ACCEPTED:

ORDER NO.

COMMISSION SECRETARY

3. IRRIGATION SERVICE

RATE SCHEDULE 1401 – IRRIGATION SERVICE

Availability	For motor loads of 746 watts or more used for irrigation and outdoor sprinkling where Electricity will be used principally during the Irrigation Season as defined below. Supply is 60 hertz, single or three phase at the Secondary or Primary Voltage available. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone I and Rate Zone IB.
Rate	1. During the Irrigation Season: **Energy Charge:** 6.12 ¢ per kWh **Minimum Charge:** $6.12 per kilowatt of connected load per month for a period of eight months commencing in March in any year whether Energy consumption is registered or not. 2. During the Non-Irrigation Season: **Energy Charge:** First 150 kWh @ 6.12 ¢ per kWh All additional kWh @ 48.52 ¢ per kWh **Minimum Charge:** Where Energy consumption is 500 kWh or less, Nil. Where Energy consumption is more than 500 kWh, $48.94 per kilowatt of connected load.
Discount for Ownership of Transformers	A discount of 25 ¢ per month per kW of connected load will be applied to the above charges if a Customer supplies the Transformation.

ACCEPTED:______________________________

ORDER NO.______________________________

COMMISSION SECRETARY

Definitions	1. Irrigation Season: In respect of each Service Connection the period commencing with a meter reading on or about March 1 in any year, having a mid-season meter reading on or about July 31, and ending with a meter reading on or about October 31 in that same year. BC Hydro may, in its discretion extend such period by postponing the termination date to any date not later than November 30, for the sole purpose of permitting a Customer to fill reservoirs necessary for the operation of the irrigation or sprinkling system. 2. Non-Irrigation Season: The period commencing at the end of one Irrigation Season and terminating at the beginning of the next Irrigation Season.
Special Conditions	1. No equipment provided with Electricity under this Rate Schedule will be served with Electricity under any other Rate Schedule while the Customer's Service Agreement under this Rate Schedule is in force. 2. Normally the Service Connection will be energized during the Non-Irrigation Season, but will be Disconnected if a Customer so requests. 3. The Minimum Charge during the Irrigation Season will commence in March for an account that has not been Terminated by the Customer, whether or not the Service Connection is energized and will be billed in two installments, at the end of July and at the end of October. 4. For the Irrigation Season, a bill will be rendered following the July and October meter readings. The first bill will be the greater of the Energy Charge and the Minimum Charge for the period March 1 to July 31. The second bill will be the greater of the Energy Charge for the season and the Minimum Charge for the season, less payment received for the first billing charges.

ACCEPTED:____________________

ORDER NO.____________________ ________________________

COMMISSION SECRETARY

	5. For the Non-Irrigation Season a bill will be rendered following the March meter reading provided that there is registered Energy consumption. 6. If a motor is rated in horsepower, the conversion factor from horsepower to kilowatts will be: 1 horsepower = 0.746 kilowatts
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019 the rates under this Rate Schedule include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

ACCEPTED:

ORDER NO.

COMMISSION SECRETARY

4. STREET LIGHTING SERVICE

RATE SCHEDULE 1701 – OVERHEAD STREET LIGHTING

Availability	For lighting of public highways, streets and lanes in cases where BC Hydro owns, installs and maintains the fixtures, conductors, controls and poles.
Applicable in	Any area served by suitable overhead distribution lines.
Rate	Per fixture per month as set out below: 100 watt H.P. sodium vapour unit $19.60 150 watt H.P. sodium vapour unit $23.38 200 watt H.P. sodium vapour unit $26.99 *175 watt mercury vapour unit $21.54 *250 watt mercury vapour unit $24.82 *400 watt mercury vapour unit $31.99 Wattages are lamp watts. * Note Special Condition No. 2.
Special Conditions	1. Connection Charge No charge will be made for Service Connections. 2. Mercury Vapour Mercury vapour fixtures are not available for new installations.

ACCEPTED:

ORDER NO.

COMMISSION SECRETARY

	3. Extension Policy BC Hydro will construct a distribution Extension if required by the applicant in accordance with the Terms and Conditions of the Electric Tariff as applicable. When, at the Customer's request, a new fixture replaces an existing fixture, the Customer will pay to BC Hydro the original cost of the existing fixture, less any accumulated depreciation, and the cost of removing the existing fixture. 4. Relocation and Redirection of Fixtures The Customer will pay the full cost of relocating or redirecting fixtures when the change is made at the request of the Customer. 5. Design BC Hydro will design the installation of overhead street lighting fixtures. 6. Lamps Failing to Operate BC Hydro will, without charge, replace lamps or components that fail to operate, unless breakage is the reason for such failure in which case the Customer will be charged the cost of the material required to make the fixture operate. 7. Term of Service Agreement The term of the initial Service Agreement under this Rate Schedule will be not more than five years; renewal periods will be for five years.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase	Effective April 1, 2019 the rates under this Rate Schedule include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

ACCEPTED:______________________

ORDER NO.______________________

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COMMISSION SECRETARY

4. STREET LIGHTING SERVICE

RATE SCHEDULE 1702 – PUBLIC AREA ORNAMENTAL STREET LIGHTING

Availability	For lighting of public highways, streets and lanes and municipal pathways and for public area seasonal lighting displays, in those cases where the Customer owns, installs and maintains the standards, fixtures, conductors and controls.
Applicable in	All Rate Zones.
Rate	**Energy Charge:** For each unmetered fixture: 3.77 ¢ per watt of Billing Wattage per month For each metered fixture: 11.32 ¢ per kWh
Definitions	Billable Wattage is the sum of all wattage, on all fixtures used by the Customer. For fixtures without dimming controls, the watts per fixture will include the wattage of the lamp plus, where applicable, the wattage of the ballast. For fixtures with dimming controls, the watts per fixture will be equal to: 1. The wattage of the lamp plus, where applicable, the wattage of the ballast, multiplied by 2. The ratio of effective fixture wattage after dimming to fixture wattage before dimming.

ACCEPTED:______________________

ORDER NO.______________________

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COMMISSION SECRETARY

Special Conditions	1. Service Connection Where necessary BC Hydro will provide an overhead or underground Service Connection in accordance with the Terms and Conditions of the Electric Tariff. No Service Connection will be made to add any ornamental street lighting system which does not provide for eight or more street lighting fixtures except that, if the potential is 120/240 volts, at BC Hydro's discretion, a Service Connection may be made for a system of less than eight. Receptacle loads will be permitted for Service under this Rate Schedule provided that such receptacles are used predominantly for seasonal lighting displays, meaning that no more than 10% of the usage may be for other purposes. 2. Extension Policy BC Hydro will construct a distribution Extension if required by the applicant in accordance with the Terms and Conditions of the Electric Tariff. 3. Power Factor All installations of mercury vapour, sodium vapour or fluorescent lamps will be equipped with the necessary auxiliaries to assure that a Power Factor of not less than 90% lagging will be maintained. 4. Term of Service Agreement The term of the initial Service Agreement under this Rate Schedule will be not more than five years; renewal periods will be for five years.

	5. Fixtures with Automated Dimming Controls The following special terms and conditions apply to lighting fixtures fitted with dimming controls: (a) For purposes of this Special Condition No. 5, “dimming controls” means control units or fittings attached to, or forming part of, a street lighting fixture capable of being programmed or remotely operated so as to reduce the lumens output of the lamps during specified hours each day while the lamps are in operation. The reductions may vary according to the hours of the day, the days of the week, and the seasons of the year. (b) A Customer wishing to have fixtures with dimming controls separately rated under this Rate Schedule must submit a dimming schedule satisfactory to BC Hydro listing each light fixture fitted with dimming controls, the wattage of the fixture (including the lamp and, where applicable, the ballast), the dimming control setting or settings and the hours each day that the dimming control setting or settings will be in operation. (c) Whenever the Customer wishes to make changes in the lighting fixtures listed in the dimming schedule or in the dimming control settings or hours of operation, the Customer will submit an updated lighting fixture schedule to BC Hydro listing any changes. Changes will be permitted on a semi-annual basis (twice per year).

ACCEPTED:______________________

ORDER NO.______________________ ______________________
COMMISSION SECRETARY

	6. Unmetered Service (a) BC Hydro may permit unmetered Service under this Rate Schedule if it can estimate to its satisfaction the Energy used in kilowatt hours over a period of one month based on the connected load and hours of use. (b) The Customer will notify BC Hydro immediately of any proposed or actual change in load, or load characteristics, or hours of use. (c) BC Hydro, in its discretion, may at any time install Metering Equipment and thereafter bill the Customer on the Energy consumption registered.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019 the rates under this Rate Schedule include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

4. STREET LIGHTING SERVICE

RATE SCHEDULE 1703 – STREET LIGHTING SERVICE

Availability	For lighting of public highways, streets and lanes in those cases where the Customer owns, installs and maintains the fixtures, conductors and controls on poles of BC Hydro. Available only to Customers formerly taking Service on Rate Schedule 1755, 1756, 1757, 1758, 1759 or 1767, to the City of New Westminster in respect of a portion of D.L. 172, to the Municipality of Sparwood and to the City of Vancouver.
Applicable in	The Cities of Victoria and Prince Rupert, the Municipalities of Oak Bay, Esquimalt, Saanich and Central Saanich, the Village of Sidney, the unorganized areas of Port Renfrew and Shawnigan Lake, a portion of D.L. 172 in the City of New Westminster, Natal and the City of Vancouver.
Rate	**Energy Charge:** 3.77 ¢ per watt of Billing Wattage per month plus **Contact Charge:** $1.13 per contact per month The Contact Charge is a per fixture charge for the use of pole space.
Definitions	Billable Wattage is the sum of all wattage, on all fixtures used by the Customer. For fixtures without dimming controls, the watts per fixture will include the wattage of the lamp plus, where applicable, the wattage of the ballast. For fixtures with dimming controls, the watts per fixture will be equal to: 1. The wattage of the lamp plus, where applicable, the wattage of the ballast, multiplied by 2. The ratio of effective fixture wattage after dimming to fixture wattage before dimming.

ACCEPTED:______________________________

ORDER NO.______________________________ ______________________________
COMMISSION SECRETARY

Special Conditions	1. Extension Policy No Extension will be made to provide Service to street lights under this Rate Schedule. 2. Power Factor All installations of mercury vapour, sodium vapour or fluorescent lamps will be equipped with the necessary auxiliaries to assure that a Power Factor of not less than 90% lagging will be maintained. 3. Term of Service Agreement The term of the initial Service Agreement under this Rate Schedule will be not more than five years; renewal periods will be for five years. 4. Fixtures with Automated Dimming Controls The following special terms and conditions apply to lighting fixtures fitted with dimming controls: (a) For purposes of this Special Condition No. 4, “dimming controls” means control units or fittings attached to, or forming part of, a street lighting fixture capable of being programmed or remotely operated so as to reduce the lumens output of the lamps during specified hours each day while the lamps are in operation. The reductions may vary according to the hours of the day, the days of the week, and the seasons of the year. (b) A Customer wishing to have fixtures with dimming controls separately rated under this Rate Schedule must submit a dimming schedule satisfactory to BC Hydro listing each light fixture fitted with dimming controls, the wattage of the fixture (including the lamp and, where applicable, the ballast), the dimming control setting or settings and the hours each day that the dimming control setting or settings will be in operation.

	(c) Whenever the Customer wishes to make changes in the lighting fixtures listed in the dimming schedule or in the dimming control settings or hours of operation, the Customer will submit an updated lighting fixture schedule to BC Hydro listing any changes. Changes will be permitted on a semi-annual basis (twice per year).
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019 the rates under this Rate Schedule include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

4. STREET LIGHTING SERVICE

RATE SCHEDULE 1704 – TRAFFIC CONTROL EQUIPMENT

Availability	For lighting of traffic signals, traffic signs and traffic warning devices, and other equipment for controlling or directing vehicular or pedestrian traffic on public highways in those cases where the Customer owns, installs, and maintains the standards, fixtures, controls and associated equipment.
Applicable in	All Rate Zones.
Rate	**Energy Charge:** 11.32 ¢ per kWh
Special Conditions	1. Service Connections Where necessary BC Hydro will provide an overhead or underground Service Connection in accordance with section 3 of the Terms and Conditions (Provision of Electricity). 2. Unmetered Service (a) BC Hydro may permit unmetered Service under this Rate Schedule if it can estimate to its satisfaction the Energy used in kilowatt hours over a period of one month based on the connected load and hours of use. (b) The Customer shall notify BC Hydro immediately of any proposed or actual change in load, or load characteristics, or hours of use. (c) BC Hydro, in its discretion, may at any time install a meter or meters and thereafter bill the Customer on the consumption registered.

ACCEPTED:____________________

ORDER NO.____________________

COMMISSION SECRETARY

	3. Term of Service Agreement The term of the initial Service Agreement under this Rate Schedule will be not more than five years; renewal periods will be for five years.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019 the rate under this Rate Schedule includes an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

ACCEPTED:______________________________

ORDER NO.______________________________

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COMMISSION SECRETARY

4. STREET LIGHTING SERVICE

RATE SCHEDULE 1755 – PRIVATE OUTDOOR LIGHTING (CLOSED)

Availability	For outdoor lighting Service to illuminate property other than public streets or lanes (private property), where Service is provided from dusk to dawn and the supply is single phase, 60 hertz at the Secondary Voltage available. This Rate Schedule is available only in Premises served under this Rate Schedule on January 1, 1975 and only with respect to lights served under this Rate Schedule on January 1, 1975 and continuously thereafter, except BC Hydro may replace a mercury vapour unit with a high pressure sodium unit having approximately the same equivalent light output.
Applicable in	All Rate Zones.
Rate	**Charge per fixture per month as follows:** 1. Where a light is mounted on a pole that was installed by the Customer or by BC Hydro at the Customer's expense: 175 watt mercury vapour unit or replacement 100 watt H.P. sodium vapour unit — $18.37 400 watt mercury vapour unit or replacement 150 watt H.P. sodium vapour unit — $31.66

ACCEPTED:____________________

ORDER NO.____________________

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COMMISSION SECRETARY

	2. Where a light is mounted on a pole that is on public property, or an easement, and is part of BC Hydro's distribution system: 175 watt mercury vapour unit or replacement 100 watt H.P. sodium vapour unit — $19.51 400 watt mercury vapour unit or replacement 150 watt H.P. sodium vapour unit — $32.81 3. Where a light is mounted on a pole that was installed on the Customer's property by BC Hydro, at its expense, solely for the purpose of supporting the light: 175 watt mercury vapour unit or replacement 100 watt H.P. sodium vapour unit — $24.02 400 watt mercury vapour unit or replacement 150 watt H.P. sodium vapour unit — $37.81 Except that if two or more lights are mounted at one time on the same pole the rates for the additional light or lights will be as set out under part 1 above.
Special Conditions	1. BC Hydro will provide and install: (a) An outdoor light consisting of luminaire, mast arm, ballast, lamp and photo-electric control, and (b) Not more than one span of overhead secondary conductors per light. 2. The Customer will be required to contribute the estimated cost of any plant required to make Secondary Voltage available at a point not more than one span from the light; such contribution is not subject to refund.

ACCEPTED:____________________

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COMMISSION SECRETARY

	3. BC Hydro reserves the sole right to determine whether or not a light will be installed on a pole that is part of BC Hydro's distribution system. 4. The prior approval of BC Hydro is required if a Customer intends to install its own poles, and such poles will be maintained to BC Hydro's satisfaction at the Customer's expense. 5. BC Hydro will maintain all equipment owned by BC Hydro and will replace lamps which have failed. Any breakage will be repaired by BC Hydro at the Customer's expense.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019 the rates under this Rate Schedule include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

ACCEPTED:____________________

ORDER NO.____________________

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COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1823 – TRANSMISSION SERVICE – STEPPED RATE

Availability	For all purposes. Supply is at 60 kV or higher. Customers supplied with Electricity under Rate Schedule 1825 (Time-of-Use) may only revert to Service under this Rate Schedule as permitted under Rate Schedule 1825.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Demand Charge:** \$8.697 per kVA of Billing Demand per Billing Period plus **Energy Charge: A** For new Customers and Customers that do not have a CBL by order of the British Columbia Utilities Commission: 5.098 ¢ per kWh for all kWh per Billing Period This rate will apply until the Customer has been supplied with Electricity under this Rate Schedule for 12 Billing Periods or another period approved by the British Columbia Utilities Commission, after which the Customer will be supplied with Electricity at the rate specified in Part B below.

ACCEPTED:______________________________

ORDER NO.______________________________

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COMMISSION SECRETARY

	Energy Charge: B For Customers with a CBL: 4.535 ¢ per kWh applied to all kWh up to and including 90% of the Customer's CBL in each Billing Year 10.160 ¢ per kWh applied to all kWh above 90% of the Customer's CBL in each Billing Year Note: Customers previously supplied with Electricity under Rate Schedule 1825 will be subject to the rates in Part B above from the time the Customer commences taking Service under this Rate Schedule. **Monthly Minimum Charge:** $8.697 per kVA of Billing Demand
Definitions	1. Billing Year The Billing Year is the 12 month billing period starting with the first day of the Billing Period which commences nearest to April 1 in each year, and ending on the last day of such 12-month Billing Period. 2. Billing Demand The Billing Demand will be: (a) The highest kVA Demand during the High Load Hours (**HLH**) in the Billing Period; or (b) 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or (c) 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant, whichever is the highest value, provided that for new Customers the Billing Demand for the initial two Billing Periods will be the average of the daily highest kVA Demands for the Customer's Plant.

ACCEPTED:______________________

ORDER NO.______________________

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	3. Customer Baseline Load (**CBL**) The Customer Baseline Load (**CBL**) is the Customer's historic annual energy consumption in kWh as approved by the British Columbia Utilities Commission. The Customer's CBL will initially be determined by BC Hydro, and be subject to revision from time to time, in accordance with the criteria and procedures set forth in BC Hydro's "Customer Baseline Load (**CBL**) Determination Guidelines" (Electric Tariff Supplement No. 74). All CBLs will be subject to final approval of the British Columbia Utilities Commission. 4. High Load Hours (**HLH**) High Load Hours (**HLH**) is the period of hours from 06:00 to 22:00 Monday to Saturday, except for Statutory Holidays (New Year's Day, Family Day, Good Friday, Victoria Day, Canada Day, B.C. Day, Labour Day, Thanksgiving Day, Remembrance Day and Christmas Day). 5. Low Load Hours (**LLH**) Low Load Hours (**LLH**) are all hours other than HLH.
Special Conditions	1. A Customer having two or more operating plants may elect to have a single aggregated CBL determined for all or any combination of its operating plants in accordance with BC Hydro's "Customer Baseline Load (**CBL**) Determination Guidelines" (Electric Tariff Supplement No. 74). Thereafter, BC Hydro will issue a single bill for all operating plants included in the aggregation, and the Energy Charge payable will be determined on the basis of the aggregated CBL. However, the Demand Charge will continue to be determined separately for each operating plant.

	2. If any initial, revised, or aggregate CBL for a Customer has not been determined by BC Hydro and approved by British Columbia Utilities Commission by the time at which the CBL would become effective, BC Hydro may determine the CBL on an interim basis and apply that CBL for the purposes of any billing periods and bills rendered to the Customer until such time as the CBL has been finally determined and approved by the British Columbia Utilities Commission, following which BC Hydro will make any necessary billing adjustments. 3. If a Customer taking Service at the rates in Part B of the Energy Charge rate section above Terminates Service under this Rate Schedule prior to the end of a Billing Year, the Customer's CBL or aggregate CBL will be prorated for the portion of the Billing Year during which the Customer was taking Service, and the prorated CBL or aggregate CBL will be used for the purposes of applying the rates in Part B to all energy consumption during the Billing Year up to the time of Termination. BC Hydro will make any necessary billing adjustments and bill the Customer for the difference (if any) owing.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Note	The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement Nos. 5 and 6, or Electric Tariff Supplement Nos. 87 and 88, as applicable.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase	Effective April 1, 2019 the rates under this Rate Schedule include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. _____.

ACCEPTED:____________________________

ORDER NO.____________________________ ____________________________________
COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1825 – TRANSMISSION SERVICE – TIME-OF-USE (TOU) RATE

Availability	For Customers who provide notice by February 15 of each year and who at the time of application are eligible to take Service under Rate Schedule 1823 (Stepped Rate) at the Energy Charge rates set out in Part B of the rate section of that Rate Schedule, and who have entered into a TOU (Transmission Service) Agreement by March 15 of that year. Customers will start Service under Rate Schedule 1825 in the first Billing Period after April 1.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Demand Charge:** $8.697 per kVA of Billing Demand per Billing Period plus **Energy Charge:** 1. Winter HLH Period: 4.535 ¢ per kWh applied to all kWh up to and including 90% of the Customer's Winter HLH Period CBL. 11.337 ¢ per kWh applied to all kWh above 90% of the Customer's Winter HLH Period CBL. 2. Winter LLH Period: 4.535 ¢ per kWh applied to all kWh up to and including 90% of the Customer's Winter LLH Period CBL. 10.275 ¢ per kWh applied to all kWh above 90% of the Customer's Winter LLH Period CBL.

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	3. Spring Period: 4.535 ¢ per kWh applied to all kWh up to and including 90% of the Customer’s Spring Period CBL. 9.151 ¢ per kWh applied to all kWh above 90% of the Customer’s Spring Period CBL. 4. Remaining Period: 4.535 ¢ per kWh applied to all kWh up to and including 90% of the Customer’s Remaining Period CBL applicable. 10.035 ¢ per kWh applied to all kWh above 90% of the Customer’s Energy CBL applicable in the Billing Period.
Definitions	1. Billing Demand The Demand for billing purposes will be: (a) The highest kVA Demand during the High Load Hours (**HLH**) in the Billing Period; or (b) 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or (c) 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant, whichever is the highest value.

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	2. Customer Baseline Load (CBL) The Customer Baseline Load (**CBL**) is the Customer's historic consumption (in kWh) as approved by the British Columbia Utilities Commission. For the purposes of this Rate Schedule, the Customer's CBL will consist of four separate CBLs – one each for the Winter HLH Period, the Winter LLH Period, the Spring Period and the Remaining Period. The Customer's CBL will initially be determined by BC Hydro, and be subject to revision from time to time, in accordance with the criteria and procedures set forth in BC Hydro's "Customer Baseline Load (**CBL**) Determination Guidelines" (Electric Tariff Supplement No. 74). All CBLs will be subject to final approval of the British Columbia Utilities Commission. 3. High Load Hours (**HLH**) High Load Hours (**HLH**) is the period of hours from 06:00 to 22:00 Monday to Saturday, except for Statutory Holidays (New Year's Day, Family Day, Good Friday, Victoria Day, Canada Day, B.C. Day, Labour Day, Thanksgiving Day, Remembrance Day and Christmas Day). 4. Low Load Hours (**LLH**) The Low Load Hours (**LLH**) are all hours other than HLH. 5. Remaining Period The Remaining Period is all Billing Periods other than the Winter Period or the Spring Period. 6. Spring Period The Spring Period comprises the two Billing Periods starting with the first day of the Billing Period that commences nearest to May 1 each year and ending on the last day of the second Billing Period thereafter.

	7. Winter Period The Winter Period comprises four Billing Periods starting with the first day of the Billing Period that commences nearest to November 1 each year and ending on the last day of the fourth Billing Period thereafter.
Special Conditions	1. Service under this Rate Schedule will be provided only while a TOU (Transmission Service) Agreement with the Customer is in effect. 2. A Customer having two or more operating plants may elect to have a single aggregated CBL determined for all or any combination of its operating plants in accordance with BC Hydro's "Customer Baseline Load (CBL) Determination Guidelines" (Electric Tariff Supplement No. 74). Separate Energy CBL values will be determined for each plant and then aggregated. BC Hydro will issue a single bill for all operating plants included in an aggregation, and the Energy Charge payable will be determined on the basis of the aggregated Energy CBL value. The Demand Charge will continue to be determined separately for each operating plant. 3. If any initial, revised, or aggregate CBL for a Customer has not been determined by BC Hydro and approved by British Columbia Utilities Commission by the time at which the CBL would become effective, BC Hydro may determine the CBL on an interim basis and apply that CBL for the purposes of any billing periods and bills rendered to the Customer until such time as the CBL has been finally determined and approved by the British Columbia Utilities Commission, following which BC Hydro will make any necessary billing adjustments.

ACCEPTED:______________________

ORDER NO.______________________

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COMMISSION SECRETARY

	4. In accordance with the TOU (Transmission Service) Agreement, the Customer will have a period of 30 days following approval of the Customer's initial CBL by the British Columbia Utilities Commission within which the Customer may, by written notice to BC Hydro, withdraw from taking Service under this Rate Schedule, and revert to taking Service under Rate Schedule 1823 (Stepped Rate). This right of withdrawal is available only when the Customer first subscribes to take Service under this Rate Schedule, and is applicable only in respect of the initial CBL determination. If the Customer exercises this right of withdrawal Rate Schedule 1823 will apply from the commencement of the then current Billing Year, and BC Hydro will make any necessary billing adjustments accordingly. 5. Customers taking Service under Rate Schedule 1852 (Modified Demand) may not also take Service under this Rate Schedule.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Note	The terms and conditions under which Transmission Service is supplied are contained in the Electricity Supply Agreement (Electric Tariff Supplement No. 5, or Electric Tariff Supplement No. 87, as applicable) as amended by the Electric Tariff Supplement No. 72 (TOU (Transmission Service) Agreement), and Electric Tariff Supplement No. 6, or Electric Tariff Supplement No. 88, as applicable.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019 the rates under this Rate Schedule include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

ACCEPTED:________________________

ORDER NO.________________________ ____________________________

COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1827 – TRANSMISSION SERVICE – RATE FOR EXEMPT CUSTOMERS

Availability	For all purposes. Supply is at 60 kV or higher. Only for City of New Westminster and University of British Columbia and other Customers exempted from Rate Schedule 1823 (Stepped Rate) by the British Columbia Utilities Commission.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Demand Charge:** \$8.697 per kVA of Billing Demand per Billing Period plus **Energy Charge:** 5.098 ¢ per kWh for all kWh in a Billing Period **Monthly Minimum Charge:** \$8.697 per kVA of Billing Demand
Definitions	1. Billing Demand The Billing Demand will be: (a) The highest kVA Demand during the High Load Hours (**HLH**) in the Billing Period; or (b) 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or (c) 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant, whichever is the highest value.

ACCEPTED:____________________

ORDER NO.____________________

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	2. High Load Hours (**HLH**) High Load Hours (**HLH**) is the period of hours from 06:00 to 22:00 Monday to Saturday, except for Statutory Holidays (New Year's Day, Family Day, Good Friday, Victoria Day, Canada Day, B.C. Day, Labour Day, Thanksgiving Day, Remembrance Day and Christmas Day). 3. Low Load Hours (**LLH**) Low Load Hours (**LLH**) are all hours other than HLH.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Note	The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement Nos. 5 and 6, or Electric Tariff Supplements Nos. 87 and 88, as applicable.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019 the rates under this Rate Schedule include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. _____.

ACCEPTED:____________________________

ORDER NO.____________________________

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COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1852 – TRANSMISSION SERVICE – MODIFIED DEMAND

Availability	To a Customer supplied with Electricity at 60 kV or higher who is taking Service under Rate Schedule 1823 (Stepped Rate) at the time of application, and is a party to a Modified Demand Agreement under Electric Tariff Supplement No. 54 which is in force, and which is in a location, as determined by BC Hydro, that will allow BC Hydro to curtail load to alleviate a potential local or regional transmission constraint, or take advantage of a market opportunity. The annual subscription period for new subscribers is from September 1 to October 31.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Excess Demand Charge:** $8.697 per kVA of metered kVA Demand in excess of the Maximum Demand Level during Low Load Hours
Definitions	1. Billing Demand The Billing Demand will be: (a) The highest kVA Demand during the High Load Hours (**HLH**) in the Billing Period; or (b) 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or (c) 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant, whichever is the highest value.

ACCEPTED:______________________

ORDER NO.______________________

COMMISSION SECRETARY

	2. High Load Hours (**HLH**) High Load Hours (**HLH**) means the period(s) in a 24-hour day and during those days of a calendar week in which Electricity usage is typically highest in a particular region, as determined by BC Hydro in its discretion based on load characteristics and transmission constraints in that region from time to time, and designated in a Modified Demand Agreement. 3. Low Load Hours (**LLH**) Low Load Hours (**LLH**) are all hours other than HLH. 4. LLH CBL Energy LLH CBL Energy means the highest monthly energy consumption during the LLH over the last 12 Billing Periods, or an estimate of consumption if insufficient data is available. 5. Maximum Demand Level Maximum Demand Level has the meaning set out in the Modified Demand Agreement. For a Customer with more than one designated period of High Load Hours, separate Maximum Demand Levels will be stated for each corresponding period of Low Load Hours. For a Customer with a single designated period of High Load Hours, a single Maximum Demand Level will be stated for all Low Load Hours. The highest Maximum Demand Level will not exceed 95% of Contract Demand stated in the Customer's Electricity Supply Agreement, and is subject to local transmission availability.

Special Conditions	1. The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement Nos. 5 and 6. The provisions of Rate Schedule 1823 (Stepped Rate) and Electric Tariff Supplement Nos. 5 and 6 continue to apply to Customers receiving Service under this Rate Schedule. In the case of a conflict between this Rate Schedule or the Modified Demand Agreement and Rate Schedule 1823 or Electric Tariff Supplement Nos. 5 or 6, the provisions of this Rate Schedule and the Modified Demand Agreement will govern. 2. If for any two Billing Periods the total energy consumed under Rate Schedule 1852, during the LLH, is greater than the LLH CBL Energy by 10% or more, the highest kVA Demand in each such Billing Period during the High Load Hours will be adjusted by the ratio of the average monthly LLH Energy during such two Billing Periods over the LLH CBL Energy. The adjusted highest kVA Demand will apply for a period of 12 months after the second Billing Period included in the adjustment calculation. The LLH CBL Energy will be recalculated using the consumption history of the most recent 12 Billing Periods. 3. The Minimum Reduction under the Modified Demand Agreement will be the greater of 50% of the difference between the Maximum Demand Level and the LLH CBL Demand, and 10 MW. 4. The Maximum Number of Demand Reduction Transactions under the Modified Demand Agreement will be the greater of Maximum Duration multiplied by the Maximum Number of Demand Reduction Transactions, and 48 hours.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

ACCEPTED:________________________

ORDER NO.________________________ ________________________

COMMISSION SECRETARY

Rate Increase	Effective April 1, 2019 the rate under this Rate Schedule includes an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

ACCEPTED:

ORDER NO.

COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1853 – TRANSMISSION SERVICE – IPP STATION SERVICE

Availability	For Customers who are Independent Power Producers (**IPPs**) served at transmission voltage, on an interruptible basis.
Applicable in	Rate Zone I excluding Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Energy Charge:** The sum, over the Billing Period, of the hourly energy consumed multiplied by the entry in the Intercontinental Exchange (**ICE**) Mid-Columbia (Mid-C) Peak, and Mid-C Off-Peak weighted average index price as published by the ICE in the ICE Day Ahead Power Price Report that corresponds to the time when consumption occurred, during that hour
Monthly Minimum Charge	$49.01
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. 2. BC Hydro may, without notice to the Customer, refuse to supply or terminate the supply of Electricity under this Rate Schedule if at any time BC Hydro does not have sufficient energy or capacity. 3. Prior to taking Electricity under this Rate Schedule, the Customer may be required to obtain approval from BC Hydro. BC Hydro will advise the Customer of the need to obtain approval prior to the taking of Electricity under this Rate Schedule. 4. Electricity taken under this Rate Schedule is to be used solely for maintenance and black-start requirements and will not displace electricity that would normally be generated by the Customer.

ACCEPTED:________________________

ORDER NO.________________________

COMMISSION SECRETARY

Taxes	The rates and Monthly Minimum Charge set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019 the Monthly Minimum Charge under this Rate Schedule includes an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

ACCEPTED:______________________

ORDER NO.______________________

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COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1880 – TRANSMISSION SERVICE – STANDBY AND MAINTENANCE SUPPLY

Availability	For Customers supplied with Electricity under Rate Schedule 1823 (Stepped Rate), 1825 (TOU Rate), 1827 (Rate for Exempt Customers) or 1852 (Modified Demand), on an interruptible basis.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Administrative Charge:** $150.00 per Period of Use plus **Energy Charge:** During the Period of Use, 10.160 ¢ per kWh of metered Rate Schedule 1880 energy consumption, determined as set out below
Definitions	1. HLH Reference Demand HLH Reference Demand is the highest kVA Demand in the HLH for the current Billing Period prior to the Period of Use, but excluding any prior Period of Use. If the Period of Use extends over an entire Billing Period, the highest kVA Demand in the HLH from the prior Billing Period will be used in determining the HLH Reference Demand, excluding any Period of Use in the prior Billing Period. For the purpose of determining HLH Reference Demand, the HLH periods are as defined in Rate Schedule 1823, 1825, 1827 or 1852, whichever is applicable. 2. Period of Use A period of consecutive hours during which Electricity is taken under this Rate Schedule. The Period of Use is as defined by the Customer when requesting Service from BC Hydro under this Rate Schedule 1880 and may extend into subsequent Billing Periods.

Rate Schedule 1880 Energy Determination	During HLH periods, the kWh consumption on an hourly basis which exceeds the HLH high kWh per hour within the Period of Use or portion thereof where HLH high kWh per hour is the product of HLH Reference Demand multiplied by the Power Factor for the half hour when the HLH Reference Demand occurred. For the purpose of the Rate Schedule 1880 Energy Determination, the HLH periods are as defined in Rate Schedule 1823, 1825, 1827 or 1852, whichever is applicable.
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. 2. BC Hydro may, without notice to the Customer, refuse to supply or terminate the supply of Electricity under this Rate Schedule if at any time during the Period of Use BC Hydro does not have sufficient energy or capacity.

ACCEPTED:____________________

ORDER NO.____________________

COMMISSION SECRETARY

3. This Rate Schedule is only for the following purposes:

   To provide Electricity the Customer would otherwise generate during periods when all or part of the Customer's electrical generating plant is curtailed.

   Electricity used for this purpose may be taken on an instantaneous basis when the impact of the instantaneous pickup of loads normally provided by the Customer's electrical generation units does not occur after BC Hydro has advised the Customer that a period of system constraint or potential system constraint exists.

   During periods of potential system constraints, BC Hydro will require Customers to arm load shedding relays to ensure that the loss of electricity production from a Customer's electrical generation unit will not result in a demand greater than the Customer's Maximum kVA Demand on BC Hydro's system. BC Hydro may require the Customer to provide it with control of these load shedding relays. During periods of potential system constraints, upon a Customer's request, BC Hydro will endeavour to provide Electricity normally provided by the Customer's electrical generation unit.

   The Customer is required to advise BC Hydro within 30 minutes of taking Electricity under this Rate Schedule for this purpose. If the Customer fails to advise BC Hydro within 30 minutes, measured Demand and Energy consumption will be billed under Rate Schedule 1823, 1825, 1827 or 1852, whichever is applicable.

4. Electricity taken under this Rate Schedule will not displace Electricity otherwise to be taken by the Customer under Rate Schedule 1823, 1825, 1827 or 1852.

   Electricity taken under this Rate Schedule will not displace electricity that would normally be generated by the Customer for the purpose of re-sale.

	5. In addition to the charges specifically set out in this Rate Schedule, the Customer will pay for any additional facilities required to deliver Electricity under this Rate Schedule provided that BC Hydro obtains the prior consent of the Customer for construction of the additional facilities. 6. A Customer may be required to allow BC Hydro to install metering and communication equipment to measure the electricity output of the Customer's self-generation unit. 7. BC Hydro will bill for Electricity taken under Rate Schedule 1880 at the same time it bills for Electricity taken under Rate Schedule 1823, 1825, 1827 or 1852, whichever is applicable.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Note	The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement Nos. 5 and 6, or Electric Tariff Supplement Nos. 87 and 88, as applicable.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019 the Energy Charge under this Rate Schedule includes an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

ACCEPTED:______________________________

ORDER NO.______________________________

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COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1891 – TRANSMISSION SERVICE – SHORE POWER SERVICE

Availability	For the supply of Shore Power to Port Customers for use by Eligible Vessels while docked at the Port Customer's Port Facility, on an interruptible basis. Supply is at 60 kV or higher.
Applicable in	Rate Zone I.
Rate	**Administrative Charge:** $150.00 per month plus **Energy Charge:** 10.160 ¢ per kWh for all kWh in a billing period
Definitions	For purposes of this Rate Schedule, capitalized terms have the meanings given to them in the Shore Power Service Agreement (Electric Tariff Supplement No. 86).
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. BC Hydro may refuse Service under this Rate Schedule in circumstances where BC Hydro does not have sufficient energy or capacity. For greater certainty, BC Hydro will not be required to construct a System Reinforcement under Electric Tariff Supplement No. 6 to provide Shore Power Service under this Rate Schedule. 2. The terms and conditions under which Shore Power Service is supplied are contained in the Shore Power Service Agreement (Electric Tariff Supplement No. 86). The Port Customer will pay to BC Hydro the charges set out in this Rate Schedule in addition to any charges set out in the Shore Power Service Agreement.

ACCEPTED:__________________________

ORDER NO.__________________________ __________________________________

COMMISSION SECRETARY

	3. A Port Customer that provides Port Electricity at a Port Facility under Rate Schedules 1600, 1601, 1610, 1611 (Large General Service) or 1823 (Stepped Rate) is not eligible to take Shore Power Service under this Rate Schedule to provide Port Electricity to that Port Facility, or a Port Facility served by the same BC Hydro delivery facilities. 4. On each occasion, if any, that BC Hydro is required to dispatch power line technicians or other workers to operate the switchgear for each connect and disconnect of Eligible Vessels docked at the Port Customer's Port Facility, BC Hydro will charge, and the Port Customer will pay, the reasonable time and labour costs for this service. The charge will be based on prevailing BC Hydro contracted labour rates and will be separately itemized on the Port Customer's monthly bill.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

ACCEPTED:____________________________

ORDER NO.____________________________

COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 3808 – TRANSMISSION SERVICE – FORTISBC INC.

Availability	This Rate Schedule is available to FortisBC Inc. (FortisBC) in accordance with the terms and conditions of the Agreement between BC Hydro and FortisBC entered into and deemed effective July 1, 2014 (Power Purchase Agreement). Contract Demand must not exceed 200 MW in any hour.
Applicable in	For Electricity delivered to FortisBC at each Point of Delivery as defined in the Power Purchase Agreement.
Rate	**Demand Charge:** \$8.697 per kW of Billing Demand per Billing Month plus **Energy Charge:** Tranche 1 Energy Price: 5.098 ¢ per kWh Tranche 2 Energy Price: 9.509 ¢ per kWh

ACCEPTED:____________________

ORDER NO.____________________

COMMISSION SECRETARY

Definitions	1. Billing Demand The Billing Demand in any Billing Month will be the greatest of: (a) The maximum amount of Electricity (in kW) scheduled under the Power Purchase Agreement, for any hour of the Billing Month; (b) 75% of the maximum amount of Electricity (in kW) scheduled under the Power Purchase Agreement in any hour in the 11 months of the Term immediately prior to the Billing Month (or less than 11 months, if the Effective Date is less than 11 months prior to the month); and (c) 50% of the Contract Demand (in kW) for the Billing Month. If FortisBC has reduced the Contract Demand in accordance with the Power Purchase Agreement, the amount of Electricity specified in item (b) above may not exceed an amount equal to 100% of the Contract Demand. 2. Maximum Tranche 1 Amount The Maximum Tranche 1 Amount for each Contract Year is 1,041 GWh. 3. Scheduled Energy Less Than or Equal to Annual Energy Nomination In any Contract Year, for the amount of the Scheduled Energy taken or deemed to be taken that is less than or equal to the Annual Energy Nomination, FortisBC will pay: (a) The Tranche 1 Energy Price for each kWh of such Scheduled Energy taken or deemed taken that is less than or equal to the Maximum Tranche 1 Amount; and (b) The Tranche 2 Energy Price for each kWh of such Scheduled Energy taken that exceeds the Maximum Tranche 1 Amount.

	4. Scheduled Energy Exceeding the Annual Energy Nomination In any Contract Year, for the amount of the Scheduled Energy taken or deemed to be taken that exceeds the Annual Energy Nomination, FortisBC will pay: (a) 150% of the Tranche 1 Energy Price, for each kWh of such Scheduled Energy taken or deemed taken that that exceeds the Annual Energy Nomination, but is less than or equal to the Maximum Tranche 1 Amount; and (b) 115% of the Tranche 2 Energy Price, for each kWh of such Scheduled Energy taken that exceeds the Annual Energy Nomination and also exceeds the Maximum Tranche 1 Amount. 5. Annual Minimum Take In any Contract Year, FortisBC will schedule and take an amount of Electricity equal to at least 75% of the Annual Energy Nomination, and will be responsible for any Annual Shortfall.
Note	The terms and conditions under which Service is supplied to FortisBC are contained in the Power Purchase Agreement.
Taxes	The rates and charges set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

ACCEPTED:________________________

ORDER NO.________________________

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COMMISSION SECRETARY

Rate Increase	The Tranche 1 Energy Price and Demand Charge set out above are subject to the same rate adjustments as Rate Schedule 1827 (Rate for Exempt Customers). Tranche 2 Energy Price is subject to changes as provided for in the Power Purchase Agreement. Effective April 1, 2019 the Tranche 1 Energy Price and the Demand Charge under this Rate Schedule include an interim rate increase of 6.85% before rounding, approved by BCUC Order No. .

6. OTHER

RATE SCHEDULE 1901 – DEFERRAL ACCOUNT RATE RIDER

Applicability	The Deferral Account Rate Rider as set out below applies to all charges payable under other Rate Schedules of the Electric Tariff except for Rate Schedule 1903 and Electric Tariff Supplement Nos. 7, 8, 39, 77 and 94.
Deferral Account Rate Rider	No applicable charge.

ACCEPTED:______________________

ORDER NO.______________________ ______________________
COMMISSION SECRETARY

ATTACHMENT H

Annual Transmission Revenue Requirement
for Network Integration Transmission Service

1. The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be $928,236,000.

2. The amount in (1) shall be effective until amended by the Transmission Provider or modified by the Commission.

Effective April 1, 2019, this rate schedule is approved on an interim basis as per BCUC Order No. .

ACCEPTED:____________________________

ORDER NO.____________________________

COMMISSION SECRETARY

Schedule 00

Network Integration Transmission Service

Availability	For wholesale transmission of electricity.
Rate	Monthly Transmission Revenue Requirement: Customers will be charged their load ratio share of one twelfth (1/12th) of the Network Transmission Revenue Requirement per month. The Transmission Revenue Requirement is shown in Attachment H. One-twelfth of the Transmission Revenue Requirement is $77,353,000.
Taxes	The Rate and Charges contained herein are exclusive of applicable taxes.
Note	The terms and conditions under which Network Integration Transmission Service is supplied are contained in BC Hydro's OATT. Capitalized terms appearing in this Schedule, unless otherwise noted, shall have the meaning ascribed to them therein.

Effective April 1, 2019, this rate schedule is approved on an interim basis as per BCUC Order No. .

ACCEPTED:____________________________

ORDER NO.____________________________

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COMMISSION SECRETARY

Schedule 01

Point-To-Point Transmission Service

Availability	For transmission of electricity on a firm and non-firm basis from one or more Point(s) of Receipt (POR) to one or more Point(s) of Delivery (POD).
Rate for Long-Term Firm Service	The Reserved Capacity Charge for the Long-Term Firm Service Rate will be up to a maximum price as set out below except where the POD is a point of interconnection between the Transmission System and the transmission system of FortisBC Inc., in which case the rate shall be zero ($0.00). The Maximum Reserved Capacity Charge is $78,433/MW of reserved capacity per year to be invoiced monthly. Reserved Capacity Billing Demand The Reserved Capacity Billing Demand is determined for each POR(s), POD(s) pair. The Reserved Capacity for each pair of POR(s) and POD(s) will be the maximum non-coincident sum of the designated POR(s) and POD(s) included in the pair.

ACCEPTED:______________________

ORDER NO.______________________ ______________________
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Schedule 01 – Point-To-Point Transmission Service (continued)

Rate for Short-Term Firm and Non-Firm Service	The posted prices for Short-Term Firm and Non-Firm Service will be less than or equal to a maximum price ($/MWh) as set out below, except where the POD is a point of interconnection between the Transmission System and the transmission system of FortisBC Inc., in which case the rate shall be zero ($0.00). Maximum Price for: 1. Monthly delivery: $6,536.12/MW of Reserved Capacity per month. 2. Weekly delivery: $1,508.34/MW of Reserved Capacity per week. 3. Daily delivery: $214.89/MW of Reserved Capacity per day. 4. Hourly delivery: $8.95/MW of Reserved Capacity per hour. Discount Rate: For discounted paths posted on the Transmission Provider's OASIS, the Transmission Customer shall pay each month for Reserved Capacity Billing Demand the greater of the rates set forth below and the rate offered by the Transmission Customer and accepted by the Transmission Provider up to the maximum rate for Short-Term Firm and Non-Firm Service: 1. Hourly delivery: $3/MW of Reserved Capacity per hour in the Heavy Load Hour period (06:00-22:00, Monday - Saturday, excluding NERC holidays) and $1/MW of Reserved Capacity per hour for the Light Load Hour period (remaining hours and days). 2. Daily delivery: sum of the hourly delivery charge in the 24 hour period in the day.
Reserved Capacity for Short-Term Firm and Non-Firm Services	The Reserved Capacity shall be the maximum of the sum of non-coincident POD(s) Capacity Reservations or sum of non-coincident POR(s) Capacity Reservations.

Schedule 01 – Point-To-Point Transmission Service (continued)

Penalty Charge	In addition to the applicable rate for service and associated charges for Ancillary Services, a penalty charge will be applied to all unauthorized usage at a rate of 125 percent of the maximum hourly delivery charge.
Special Conditions	Discounts: The following conditions apply to discounts for transmission service: 1. any offer of a discount made by BC Hydro must be announced to all Eligible Customers solely by posting on the OASIS, 2 any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, 3. once a discount is negotiated, details must be immediately posted on the OASIS, and 4. for any discount agreed upon for service on a path, from POR(s) POD(s), BC Hydro must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same POD(s) on the Transmission System.
Taxes	The Rate and Charges contained herein are exclusive of applicable taxes.
Resales	The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff
Note	The terms and conditions under which Transmission Service is supplied are contained in BC hydro's Open Access Transmission Tariff. Capitalized terms appearing in this Rate Schedule, unless otherwise noted, shall have the meaning ascribed to them therein.

Effective April 1, 2019, this rate schedule is approved on an interim basis as per BCUC Order No. ____.

ACCEPTED:____________________________

ORDER NO.____________________________

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COMMISSION SECRETARY

Schedule 03

Scheduling, System Control, and Dispatch Service

Preamble	This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by BC Hydro. The Transmission Customer must purchase this service from BC Hydro. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below.
Availability	In support of Network Integration Transmission Service, Long and Short-Term Firm Point-to-Point Transmission Service, and Non-Firm Point-to-Point Transmission Service.
Rate	$0.133 per MW of Reserved Capacity per hour.
Taxes	The Rate and Charges contained herein are exclusive of applicable taxes.
Note	A description of the methodology for discounting Scheduling, System Control and Dispatch Services provided under this Schedule is contained in Section 3 of the BC Hydro OATT.

Effective April 1, 2019, this rate schedule is approved on an interim basis as per BCUC Order No. ______.

ACCEPTED:______________________________

ORDER NO.______________________________

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COMMISSION SECRETARY

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix EE

Attachment 2

Tariff Sheets
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1. RESIDENTIAL SERVICE

RATE SCHEDULES 1101, 1121 – RESIDENTIAL SERVICE

Availability	For Residential Service. Service is normally single phase, 60 hertz at the Secondary Voltage available. In BC Hydro's discretion, Service may be three phase 120/208 or 240 volts.
Applicable in	Rate Zone I.
Rate	1. Rate Schedule 1101 – Residential Service: **Basic Charge:** 20.90~~19.56~~ ¢ per day plus **Energy Charge:** (a) For Customers billed monthly: Step 1: First 675 kWh per month@ 9.45~~8.84~~ ¢/kWh Step 2: Additional kWh per month@ 14.17~~13.26~~ ¢/kWh (b) For Customers billed bi-monthly: Step 1: First 1350 kWh per two months@ 9.45~~8.84~~ ¢/kWh Step 2: Additional kWh per two months@ 14.17~~13.26~~ ¢/kWh Note: For billing purposes, Step 1 is pro-rated on a daily basis. **Minimum Charge:** The Basic Charge

ACCEPTED:_____________________________

ORDER NO._____________________________ _____________________________

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	2. Rate Schedule 1121 – Multiple Residential Service: **Basic Charge:** 20.90~~19.56~~ ¢ per Dwelling per day plus **Energy Charge:** Per Dwelling (a) For Customers billed monthly: Step 1: First 675 kWh. per month@ 9.45~~8.84~~ ¢/kWh Step 2: Additional kWh per month@ 14.17~~13.26~~ ¢/kWh (b) For Customers billed bi-monthly: Step 1: First 1350 kWh per two months@ 9.45~~8.84~~ ¢/kWh Step 2: Additional kWh per two months@ 14.17~~13.26~~ ¢/kWh Note: For billing purposes, Step 1 is pro-rated on a daily basis. **Minimum Charge:** The Basic Charge per Dwelling
Discount for Ownership of Transformers	A discount of 25 ¢ per month per kW of Maximum Demand will be applied to amounts owing under Rate Schedule 1121 if the Customer supplies Transformation. BC Hydro will install Metering Equipment with both Demand and Energy measurement capability at the Secondary Voltage.
Special Conditions	1. The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under these Rate Schedules must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission. 2. Rate Schedule 1121 applies if the Premises contains more than two Dwellings.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.

ACCEPTED:________________________

ORDER NO.________________________

COMMISSION SECRETARY

Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under these Rate Schedules include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under these Rate Schedules include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:______________________________

ORDER NO.______________________________

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COMMISSION SECRETARY

1. RESIDENTIAL SERVICE

RATE SCHEDULE 1105 – RESIDENTIAL SERVICE – DUAL FUEL (CLOSED)

Availability	For residential space heating and water heating. Electricity purchased under this Rate Schedule will be separately metered. Service is single phase, 60 hertz, at 120/240 or 240 volts. This Rate Schedule is available only for Premises served under this Rate Schedule on January 15, 1990 and continuously thereafter and only in Premises where there has been no change in Customer since April 1, 2008.
Applicable in	Rate Zone I in areas where and when, in BC Hydro's opinion, BC Hydro's transmission, sub-transmission and distribution circuit feeders are or will be capable of handling the load.
Rate	**Energy Charge:** 7.13~~6.36~~ ¢ per kWh
Special Conditions	1. Service under this Rate Schedule is not available to any Premises where Service was previously supplied and Terminated. 2. BC Hydro will upgrade an existing Service Connection supplying firm load to serve additional load in accordance with the Electric Tariff, however, no new or additional load is permitted under this Rate Schedule at any time. All unauthorized consumption of Electricity as estimated by BC Hydro will be billed at the rate for Electricity on the appropriate default Residential Service Rate Schedule. 3. The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under this Rate Schedule must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission.

ACCEPTED:______________________

ORDER NO.______________________

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COMMISSION SECRETARY

Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	~~Effective April 1, 2016 and April 1, 2017 t~~The rate under this Rate Schedule is set in accordance with BCUC Order No. G-194-17. Effective April 1, 2019, ~~included~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively, before rounding~~, ~~both~~ approved by BCUC Order No. ,~~G-47-18~~ is applied.
	~~Effective April 1, 2018 the rate under this Rate Schedule includes an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:______________________________

ORDER NO.______________________________

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COMMISSION SECRETARY

1. RESIDENTIAL SERVICE

RATE SCHEDULES 1107, 1127 – RESIDENTIAL SERVICE – ZONE II

Availability	For Residential Service. Service is normally single phase, 60 hertz at the Secondary Voltage available. In BC Hydro's discretion, Service may be three phase 120/208 or 240 volts.
Applicable in	Rate Zone II.
Rate	1. Rate Schedule 1107 – Residential Service: **Basic Charge:** 22.29~~20.86~~ ¢ per day plus **Energy Charge:** First 1500 kWh per month @ 11.32~~10.59~~ ¢ per kWh All additional kWh per month @ 19.45~~18.20~~ ¢ per kWh **Minimum Charge:** The Basic Charge 2. Rate Schedule 1127 – Multiple Residential Service: **Basic Charge:** 22.29~~20.86~~ ¢ per Dwelling per day plus **Energy Charge:** First 1500 kWh per Dwelling per month @ 11.32~~10.59~~ ¢ per kWh All additional kWh per month @ 19.45~~18.20~~ ¢ per kWh **Minimum Charge:** The Basic Charge per Dwelling
Discount for Ownership of Transformers	A discount of 25 ¢ per month per kW of Maximum Demand will be applied to amounts owing under Rate Schedule 1127 if the Customer supplies Transformation. BC Hydro will install Metering Equipment with both Demand and Energy measurement capability at the Secondary Voltage.

ACCEPTED:____________________________

ORDER NO.____________________________ ____________________________________

COMMISSION SECRETARY

Special Conditions	1. The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under these Rate Schedules must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission. 2. Rate Schedule 1127 applies if the Premises contains more than two Dwellings.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under these Rate Schedules include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under these Rate Schedules include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:____________________________

ORDER NO.____________________________

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COMMISSION SECRETARY

1. RESIDENTIAL SERVICE

RATE SCHEDULE 1148 – RESIDENTIAL SERVICE – ZONE II (CLOSED)

Availability	For Residential Service in Rate Zone II where a permanent electric space heating system is in use, providing such system was installed prior to October 10, 1966. This Rate Schedule is available only to a Customer and Premises served under this Rate Schedule on April 24, 1992 and continuously thereafter.
Applicable in	Rate Zone II.
Rate	**Basic Charge:** 22.29~~20.86~~ ¢ per day plus **Energy Charge:** 11.32~~10.59~~ ¢ per kWh **Minimum Charge:** The Basic Charge
Special Conditions	The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under this Rate Schedule must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under this Rate Schedule include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under this Rate Schedule include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

1. RESIDENTIAL SERVICE

RATE SCHEDULES 1151, 1161 – EXEMPT RESIDENTIAL SERVICE

Availability	For Residential Service and uses exempted from Rate Schedules 1101 and 1121 (Residential Service), including: 1. Use on farms as set out in the definition of Residential Service in the Terms and Conditions; and 2. Use in Rate Zone IB. Service is normally single phase, 60 hertz at the Secondary Voltage available. In BC Hydro's discretion, Service may be three phase 120/208 or 240 volts.
Applicable in	Rate Zone I and Rate Zone IB.
Rate	1. Rate Schedule 1151 – Residential Service: **Basic Charge:** 22.29~~20.86~~ ¢ per day plus **Energy Charge:** 11.32~~10.59~~ ¢ per kWh **Minimum Charge:** The Basic Charge 2. Rate Schedule 1161 – Multiple Residential Service: **Basic Charge:** 22.29~~20.86~~ ¢ per day per Dwelling per day plus **Energy Charge:** 11.32~~10.59~~ ¢ per kWh **Minimum Charge:** The Basic Charge per Dwelling

ACCEPTED:______________________________

ORDER NO.______________________________

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BC Hydro
Rate Schedules 1151, 1161 – ~~Revision 1~~Revision 2
Effective: ~~April 1, 2018~~April 1, 2019
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Discount for Ownership of Transformers	A discount of 25 ¢ per month per kW of Maximum Demand will be applied to amounts owing under Rate Schedule 1161 if the Customer supplies Transformation. BC Hydro will install Metering Equipment with both Demand and Energy measurement capability at the Secondary Voltage.
Special Conditions	The maximum capacity of all heating elements energized at any one time in all water heaters at the Premises served under these Rate Schedules must not exceed the greater of 1,500 watts and 45 watts per litre (200 watts per imperial gallon) of tank capacity, except with BC Hydro's advance written permission.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under these Rate Schedules include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under these Rate Schedules include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:________________________

ORDER NO.________________________

COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULES 1200, 1201, 1210, 1211 – EXEMPT GENERAL SERVICE (35 KW AND OVER)

Availability	For Customers who qualify for General Service where supply is 60 hertz, single or three phase at Secondary or Primary Voltage and Billing Demand is 35 kW or more. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone IB.
Rate	**Basic Charge:** 26.73~~25.02~~ ¢ per day plus **Demand Charge:** First 35 kW of Billing Demand per Billing Period @ $0.00 per kW Next 115 kW of Billing Demand per Billing Period @ $6.52~~6.10~~ per kW All additional kW of Billing Demand per Billing Period @ $12.49~~11.69~~ per kW plus **Energy Charge:** First 14800 kWh of Energy consumption in the Billing Period @ 12.72~~11.90~~ ¢ per kWh All additional kWh of Energy consumption in the Billing Period @ 6.11~~5.72~~ ¢ per kWh

ACCEPTED:____________________

ORDER NO.____________________ ____________________

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Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per Billing Period per kW of Billing Demand will be applied to the above charges if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.
Monthly Minimum Charge	50% of the highest Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding 11 Billing Periods. For the purpose of this provision an on-peak period commences on November 1 in any year and terminates on March 31 of the following year.
Rate Schedules	1. Rate Schedule 1200: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1201: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1210: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1211: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.

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ORDER NO.____________________

COMMISSION SECRETARY

Definitions	Billing Demand is the Maximum Demand in the Billing Period, subject to Special Condition No. 1. Billing Period means a month between regular meter readings, provided that in cases where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period.
Special Conditions	1. Metering Equipment with both Demand and Energy measurement capability will normally be installed. Until such Metering Equipment is installed, or if the installed Metering Equipment does not have Demand measurement capability, Billing Demand will be as estimated by BC Hydro. 2. Migration rule: Customers taking Service under these Rate Schedules will be moved to Service under Rate Schedule 1300, 1301, 1310 or 1311 (Small General Service) if Billing Demand in each of the last 12 consecutive Billing Periods was less than 35 kW.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under these Rate Schedules included~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under these Rate Schedules include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:______________________________

ORDER NO.______________________________

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COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULES 1205, 1206, 1207 – GENERAL SERVICE – DUAL FUEL (CLOSED)

Availability	For general space heating, water heating and industrial process heating on an interruptible basis. Electricity purchased under these Rate Schedules will be separately metered. Service is 60 hertz single or three phase at the Secondary or Primary Voltage available. BC Hydro reserves the right to determine the voltage of the Service Connection. These Rate Schedules are available only for Premises served under these Rate Schedules on January 15, 1990 and continuously thereafter, only with respect to equipment served under these Rate Schedules on January 15, 1990 and continuously thereafter, and only in Premises where there has been no change in Customer since April 1, 2008.
Applicable in	Rate Zone I in areas where, in BC Hydro's opinion, BC Hydro's transmission, sub-transmission and distribution circuit feeders are or will be capable of handling the load.
Rate	Except as stated hereunder the rate will be: **Energy Charge:** First 8000 kWh per month @ 6.19~~5.79~~ ¢ per kWh All additional kWh per month @ 4.05~~3.79~~ ¢ per kWh Exception: If during a Period of Interruption a Customer fails to comply with BC Hydro's requirement to cease the use of Electricity and BC Hydro, in its sole discretion, continues to supply Electricity, the rate for such Electricity will be: **Energy Charge:** 35.98~~33.67~~ ¢ per kWh

ACCEPTED:____________________________

ORDER NO.____________________________

COMMISSION SECRETARY

Period of Interruption	A period during which a Customer is required by BC Hydro to cease the use of Electricity under these Rate Schedules.
Rate Schedules	1. Rate Schedule 1205 – Small Commercial Applications: Applies to a Customer whose interruptible heating load is mostly in support of a commercial activity and whose firm Electricity is billed on a General Service (under 35 kW) Rate Schedule. 2. Rate Schedule 1206 – Large Commercial Applications: Applies to a Customer whose interruptible heating load is mostly in support of a commercial activity and whose firm Electricity is billed on a General Service (35 kW and over) Rate Schedule. 3. Rate Schedule 1207 – Industrial Applications: Applies to a Customer whose interruptible heating load is mostly in support of an industrial activity and whose firm Electricity is billed on a General Service Rate Schedule or for farm use on a Residential Rate Schedule.
Special Conditions	1. BC Hydro may, at any time and from time to time, interrupt the supply of Electricity under these Rate Schedules whenever there is a lack of surplus hydro energy and Service cannot be provided economically from other energy sources.

ACCEPTED:______________________________

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COMMISSION SECRETARY

	2. A Customer taking Service under these Rate Schedules is required to have, to BC Hydro's satisfaction, an installed permanent backup heating system using an alternative fuel, or an installed permanent independent electrical generating system, in good working order, and an adequate supply of fuel therefor, so that the Customer can continue heating operations when the supply of Electricity is interrupted. The output rating of the backup system must be of sufficient capacity to supply the heating load served under these Rate Schedules. If at any time a Customer fails to comply with the foregoing requirements, BC Hydro may immediately Terminate the supply of Electricity under these Rate Schedules to such Customer. 3. BC Hydro will interrupt the supply of Electricity by either manual or automatic means or by written notice by registered mail or hand delivery to the Customer to cease the use of Electricity under these Rate Schedules. A Customer who has been given such written notice to cease the use of Electricity under these Rate Schedules will in accordance with the requirements of the notice cease such use and will not begin to use Electricity again until so authorized by BC Hydro, by written notice. If a Customer fails to comply with these requirements, BC Hydro may in its sole discretion: (a) Continue to supply Electricity, in which case the rate will be the rate for Electricity during a Period of Interruption as stated in these Rate Schedules, or (b) Terminate the supply of Electricity under these Rate Schedules.

ACCEPTED:____________________

ORDER NO.____________________ ____________________

COMMISSION SECRETARY

	4. The initial contract period for dual fuel interruptible Service under these Rate Schedules is: (a) One year where no new facility is required to be constructed or the only facility required to be constructed by BC Hydro to serve the Customer is a drop Service Connection, or (b) Two years where more than a drop Service Connection is required to be constructed by BC Hydro to serve the Customer. At the expiration of a contract period, the contract period is automatically extended from year to year unless either the Customer or BC Hydro gives written notice to the other 30 days prior to the anniversary date. Transfer of the load served under these Rate Schedules to a general firm Rate Schedule will not be permitted during a Period of Interruption. 5. These Rate Schedules are not available to Premises where Electricity under it was previously supplied and Terminated. 6. BC Hydro will upgrade an existing Service Connection supplying firm load to serve additional load under these Rate Schedules. The charge for upgrading will be the same as applicable to a new Service Connection. 7. For existing Customers adding load to take Service under these Rate Schedules, and where an overhead distribution Extension is required to accommodate such added load BC Hydro will contribute toward the estimate cost of the Extension an amount not exceeding two times the annual revenue as estimated by BC Hydro to be received by the applicant. Any excess cost will be contributed by the applicant.

	8. No other load than that stipulated in the Availability clause is permitted under these Rate Schedules. Any unauthorized use of Electricity or any refusal by a Customer to permit access to Premises in accordance with the Terms and Conditions of BC Hydro's Electric Tariff will result in immediate Termination under the applicable Rate Schedule and all unauthorized consumption as estimated by BC Hydro will be billed at the rate for Electricity during a Period of Interruption as stated in these Rate Schedules.
	9. In addition to and without restriction of any other limitations of liability of BC Hydro, BC Hydro will specifically not be liable for any loss, damage, injury or expense occasioned to or suffered by any Customer receiving Service on these Rate Schedules, or by any other Person, for or by reason of any interruption of Electricity supply whatsoever for any reason whatsoever.
	10. A Customer who signs a contract with BC Hydro for the supply of Electricity to new load under these Rate Schedules during the period commencing July 1, 1988 and ending December 31, 1988 will be eligible to receive an incentive rebate on his Electricity bills provided the Customer begins taking Service under these Rate Schedules no later than 12 months following the date the contract was signed.
	11. A rebate will be applied to reduce the effective rate to 1.1 ¢ per kWh. Such rebate will apply only to an accumulated maximum of $30.00 per kW of connected new load in excess of 35 kW and only up to the first two years following connection. Bills for Energy consumed will be calculated and presented at full rates with the rebate for any given period applied to the following bill. The maximum two year period of billing rebates will be extended by the equivalent of any Period of Interruption. Rebates will not be applied to reduce the rate applicable for consumption during a Period of Interruption, nor will rebates be applied to reduce Power Factor surcharges.

	12. At the conclusion of any Period of Interruption, BC Hydro may Terminate Service under these Rate Schedules to any Customer who used Electricity during a Period of Interruption, unless it can be demonstrated to BC Hydro's satisfaction that adequate standby facilities exist.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under these Rate Schedules include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under these Rate Schedules include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:____________________

ORDER NO.____________________

COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULE 1234 – SMALL GENERAL SERVICE (UNDER 35 KW) – ZONE II

Availability	For all purposes where a meter with Demand measurement capability is not installed because the Customer's Demand as estimated by BC Hydro is less than 35 kW. Supply is 60 hertz, single or three phase at an available Secondary Voltage.
Applicable in	Rate Zone II.
Rate	**Basic Charge:** 26.73~~25.02~~ ¢ per day plus **Energy Charge:** First 7000 kWh per month @ 12.72~~11.90~~ ¢ per kWh All additional kWh per month @ 21.17~~19.81~~ ¢ per kWh **Minimum Charge:** The Basic Charge
Special Conditions	Special Conditions for Unmetered Service: 1. BC Hydro may permit unmetered Service under this Rate Schedule if it can estimate to its satisfaction the Energy used in kilowatt hours over a period of two months based on the connected load and the hours of use. 2. The Customer, if required by BC Hydro, will provide and maintain such controls, including timing devices, as BC Hydro considers necessary, and facilities satisfactory to BC Hydro for the maintenance of such controls. 3. The hours of use per period will be as specified by the Customer or as estimated by BC Hydro, whichever is greater.

ACCEPTED:______________________________

ORDER NO.______________________________

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COMMISSION SECRETARY

4. The Customer will supply, install and maintain all wiring, fixtures, control devices and equipment, including the controls and devices described in Special Condition No. 2, at the expense of the Customer.

5. All wiring, fixtures, control devices and equipment and the method of installing, operating and maintaining the same are subject to the approval of BC Hydro which approval may be withdrawn by BC Hydro, at any time, at BC Hydro's sole discretion.

6. The Customer will notify BC Hydro immediately of any proposed or actual change in load, load characteristics, or hours of use.

7. BC Hydro may at any time, in its sole discretion, install Metering Equipment, and thereafter bill the Customer on the appropriate Rate Schedule as a metered account.

8. For display signs and signboard lighting, where hours of use are controlled by timing devices, the following turn-on times will apply, unless BC Hydro otherwise agrees in writing:

Period	Turn-on Time
January 1 to January 15:	4:00 p.m.
January 16 to February 28:	4:30 p.m.
March 1 to April 30:	6:30 p.m.
May 1 to August 15:	8:30 p.m.
August 16 to September 30:	6:30 p.m.
October 1 to November 15:	4:30 p.m.
November 16 to December 31:	4:00 p.m.

ACCEPTED:______________________

ORDER NO.______________________

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COMMISSION SECRETARY

	9. In all cases, where hours of use of display signs or signboard lighting commence at dusk and are controlled either by timing devices or by photo-electric cells, the following hours of use for a period of two months will be deemed for billing purposes: Dusk to 10 p.m.: 216 hours Dusk to 11 p.m.: 270 hours Dusk to 12 p.m.: 330 hours Dusk to 1 a.m.: 380 hours Dusk to Dawn: 666 hours (All times are Pacific Time.)
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under this Rate Schedule include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under this Rate Schedule include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:____________________________

ORDER NO.____________________________

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COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULE 1253 – DISTRIBUTION SERVICE – IPP STATION SERVICE

Availability	For Customers who are Independent Power Producers (**IPPs**) served at distribution voltage, on an interruptible basis.
Applicable in	Rate Zone I excluding Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Energy Charge:** The sum, over the billing period, of the hourly Energy consumed multiplied by the entry in the Intercontinental Exchange (**ICE**) Mid Columbia (Mid-C) Peak, and Mid-C Off-Peak weighted average index price as published by the ICE in the ICE Day Ahead Power Price Report that corresponds to the time when consumption occurred, during that hour.
Monthly Minimum Charge	$49.01~~45.87~~
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. 2. BC Hydro may, without notice to the Customer, refuse to supply or terminate the supply of Electricity under this Rate Schedule if at any time BC Hydro does not have sufficient energy or capacity. 3. Prior to taking Electricity under this Rate Schedule, the Customer may be required to obtain approval from BC Hydro. BC Hydro will advise the Customer of the need to obtain approval prior to the taking of Electricity under this Rate Schedule. 4. Electricity taken under this Rate Schedule is to be used solely for maintenance and black-start requirements and will not displace electricity that would normally be generated by the Customer.

Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the Monthly Minimum Charge under this Rate Schedule includes~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the Monthly Minimum Charge under this Rate Schedule includes an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:____________________________

ORDER NO.____________________________ ______________________________

COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULES 1255, 1256, 1265, 1266 – GENERAL SERVICE (35 KW AND OVER) – ZONE II

Availability	For all purposes. Supply is 60 hertz, single or three phase at Secondary or Primary Voltage. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone II.
Rate	**Basic Charge:** 26.73~~25.02~~ ¢ per day plus **Energy Charge:** First 200 kWh per kW of Billing Demand per month @ 12.72~~11.90~~ ¢ per kWh All additional kWh per month @ 21.17~~19.81~~ ¢ per kWh
Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per month per kW of Billing Demand will be applied to the above rate if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts the discount for metering at a Primary Voltage will be applied first.
Monthly Minimum Charge	The monthly minimum charge to be paid by a Customer on Rate Schedule 1255, 1256, 1265 or 1266, as applicable, will be the charge the Customer would have been billed under Rate Schedule 1200, 1201, 1210 or 1211 (Exempt General Service – 35 kW and over), respectively.
Rate Schedules	1. Rate Schedule 1255: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation.

ACCEPTED:________________________

ORDER NO.________________________

COMMISSION SECRETARY

	2. Rate Schedule 1256: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1265: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1266: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Special Conditions	1. Metering Equipment with both Demand and Energy measurement capability will normally be installed. Until such Metering Equipment is installed, or if the installed Metering Equipment does not have Demand measurement capability, Billing Demand will be as estimated by BC Hydro. 2. Where the Customer’s Demand is or is likely to be in excess of 45 kVA, BC Hydro may require such Customer to execute a special contract for Service, including such special conditions as BC Hydro, in its sole discretion considers necessary.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under these Rate Schedules include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under these Rate Schedules include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:________________________

ORDER NO.________________________

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COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULE 1268 – DISTRIBUTION SERVICE – IPP DISTRIBUTION TRANSPORTATION ACCESS

Availability	For Customers who have generators connected to BC Hydro's distribution system and who want to access BC Hydro's transmission system pursuant to and in accordance with BC Hydro's Open Access Transmission Tariff (OATT).
Applicable in	Rate Zone I excluding Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Distribution Transportation Charge:** 0.197~~0.184~~ ¢ per kWh
Special Conditions	1. The Customer is required to pay the costs, including the cost of altering existing facilities, to connect the generator to BC Hydro's distribution system in accordance with BC Hydro's Connection Requirements for Utility or Non-Utility Generation, 35 kV and Below. 2. For Customers with self-generation (i.e., with a Customer Baseline Load (**CBL**) greater than zero), this Rate Schedule is only applicable to sales of Surplus Energy. It may not be used by self-generating Customers who appear to have varied their demand for power from BC Hydro based on the actual or anticipated difference between BC Hydro's rate for providing Service to them and the market price of power. 3. For the purposes of this Rate Schedule, "Surplus Energy" in any period is the energy made available from generation by the Customer calculated as the difference between the Customer's CBL and the Customer's actual consumption from BC Hydro in that period.

ACCEPTED:____________________

ORDER NO.____________________

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COMMISSION SECRETARY

	4. The Customer's CBL is established, in general, by determining the Customer's Energy consumption, on a monthly basis, for the past three years; in cases where inadequate history exists, alternative methods may be used to determine a Customer's CBL. Once established, the Customer's CBL will not be automatically adjusted for changes in the Customer's net metered consumption from BC Hydro. Any subsequent changes to the CBL must be due to changes in the Customer's load and not due to changes in its generation. The Customer must provide metered output from its generator which demonstrates an increase in generation output commensurate in time and amount with the Surplus Energy transported using this Rate Schedule. Where it appears that the Customer has transported on this Rate Schedule Energy that is not Surplus Energy, BC Hydro will provide replacement energy to the Customer's load at market prices, subject to Commission approval for such sales. 5. The metering point to determine the electricity being delivered to BC Hydro's distribution system will be determined by BC Hydro. The electricity delivered to BC Hydro's distribution system will also be deemed to be delivered to BC Hydro's transmission system (that is, no distribution loss adjustment will be applied to the electricity from an independent power producer or self-generator when determining capacity and energy delivered to BC Hydro's transmission system).
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rate under this Rate Schedule include~~d~~s an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.

	~~Effective April 1, 2018 the rate under this Rate Schedule includes an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:______________________________

ORDER NO.______________________________

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COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULE 1280 – SHORE POWER SERVICE (DISTRIBUTION)

Availability	For the supply of Shore Power to Port Customers who qualify for General Service for use by Eligible Vessels while docked at the Port Customer's Port Facility, on an interruptible basis. Shore Power Service is supplied at 60 Hz, three phase at Primary Voltage.
Applicable in	Rate Zone I.
Rate	**Administrative Charge:** $150.00 per month plus **Energy Charge:** 10.510~~9.836~~ ¢ per kWh
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. BC Hydro may refuse or Terminate Service under this Rate Schedule in circumstances where BC Hydro does not have sufficient energy or capacity. For greater certainty, BC Hydro will not be required to construct an Extension for the purpose of increasing the capacity of BC Hydro's distribution system to provide Shore Power Service under this Rate Schedule. 2. The terms and conditions under which Shore Power Service is supplied are contained in the Shore Power Service Agreement (Electric Tariff Supplement No. 86). The Port Customer will pay to BC Hydro the charges set out in this Rate Schedule in addition to any charges set out in the Shore Power Service Agreement. 3. A Port Customer that provides Port Electricity at a Port Facility under Rate Schedules 1600, 1601, 1610, 1611 or 1823 is not eligible to take Shore Power Service under this Rate Schedule to provide Port Electricity to that Port Facility, or any Port Facility served by the same BC Hydro delivery facilities.

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	4. On each occasion, if any, that BC Hydro is required to dispatch power line technicians or other workers to operate the switchgear for each connect and disconnect of Eligible Vessels docked at the Port Customer's Port Facility, BC Hydro will charge, and the Port Customer will pay, the reasonable time and labour costs for this service. The charge will be based on prevailing BC Hydro contracted labour rates and will be separately itemized on the Port Customer's monthly bill.
Definitions	For purposes of this Rate Schedule, capitalized terms have the meanings given to them in Electric Tariff Supplement No. 86.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

2. GENERAL SERVICE

RATE SCHEDULES 1300, 1301, 1310, 1311 – SMALL GENERAL SERVICE (UNDER 35 KW)

Availability	For Customers who qualify for General Service and whose Demand, metered or estimated by BC Hydro, as applicable, is less than 35 kW. Supply is 60 hertz, single or three phase at a Secondary or Primary Voltage.
Applicable in	Rate Zone I and Rate Zone IB.
Rate	**Basic Charge:** 36.45~~34.11~~ ¢ per day plus **Energy Charge:** 12.53~~11.73~~ ¢ per kWh **Minimum Charge:** The Basic Charge
Discounts	1. A discount of 1½% will be applied to the above charges if Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per month per kW of Demand will be applied if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.
Rate Schedules	1. Rate Schedule 1300: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1301: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation.

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	3. Rate Schedule 1310: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1311: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Special Conditions	Special Conditions for Unmetered Service: 1. BC Hydro may permit unmetered Service under these Rate Schedules if it can estimate to its satisfaction the Energy used in kilowatt hours over a period of two months based on the connected load and the hours of use. 2. The Customer, if required by BC Hydro, will provide and maintain such controls, including timing devices, as BC Hydro considers necessary, and facilities satisfactory to BC Hydro for the maintenance of such controls. 3. The hours of use per period will be as specified by the Customer, or as estimated by BC Hydro, whichever is greater. 4. The Customer will supply, install and maintain all wiring, fixtures, control devices and equipment, including the controls and devices described in Special Condition No. 2, at the expense of the Customer. 5. All wiring, fixtures, control devices and equipment and the method of installing, operating and maintaining the same are subject to the approval of BC Hydro which approval may be withdrawn by BC Hydro, at any time, at BC Hydro's sole discretion. 6. The Customer will notify BC Hydro immediately of any proposed or actual change in load, load characteristics, or hours of use.

7. BC Hydro may at any time, in its sole discretion, install Metering Equipment, and thereafter bill the Customer on the appropriate Rate Schedule as a metered account.

8. For display signs and signboard lighting, where hours of use are controlled by timing devices, the following turn-on times will apply, unless BC Hydro otherwise agrees in writing:

Period	Turn-on Time
January 1 to January 15:	4:00 p.m.
January 16 to February 28:	4:30 p.m.
March 1 to April 30:	6:30 p.m.
May 1 to August 15:	8:30 p.m.
August 16 to September 30:	6:30 p.m.
October 1 to November 15:	4:30 p.m.
November 16 to December 31:	4:00 p.m.

9. In all cases, where hours of use of display signs or signboard lighting commence at dusk and are controlled either by timing devices or by photo-electric cells, the following hours of use for a period of two months will be deemed for billing purposes:

Dusk to 10 p.m.:	216 hours
Dusk to 11 p.m.:	270 hours
Dusk to 12 p.m.:	330 hours
Dusk to 1 a.m.:	380 hours
Dusk to Dawn:	666 hours

(All times are Pacific Time.)

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	Migration Rules: 1. Migration rules from Small General Service: Customers taking Service under these Rate Schedules will be moved to Service: (a) Under Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) if Demand in half of the last six bi-monthly billing periods or half of the last 12 monthly billing periods (as applicable) was 35 kW or more, but less than 150 kW. (b) Under Rate Schedules 1600, 1601, 1610 or 1611 (Large General Service) if Demand in half of the last six bi-monthly billing periods or half of the last 12 monthly billing periods (as applicable) was 150 kW or more, or if total Energy consumption in any 12 consecutive month period exceeded 550,000 kWh. 2. Migration rules to Small General Service: Customers will be moved to Service under these Rate Schedules (Small General Service) from Rate Schedules 1600, 1601, 1610 or 1611 (Large General Service) or Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) if Billing Demand in each of the last 12 billing periods was less than 35 kW.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under these Rate Schedules include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under these Rate Schedules include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:

ORDER NO.

COMMISSION SECRETARY

2. GENERAL SERVICE

RATE SCHEDULES 1500, 1501, 1510, 1511 – MEDIUM GENERAL SERVICE (35 KW OR GREATER AND LESS THAN 150 KW)

Availability	For Customers who qualify for General Service and whose Billing Demand is equal to or greater than 35 kW but less than 150 kW, and whose Energy consumption in any 12-month period is equal to or less than 550,000 kWh. Supply is 60 hertz, single or three phase at Secondary or Primary Voltage. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone I.
Rate	**Basic Charge:** 26.73~~25.02~~ ¢ per day plus **Demand Charge:** $5.42~~5.07~~ per kW of Billing Demand plus **Energy Charge:** 9.68~~9.06~~ ¢ per kWh
Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per Billing Period per kW of Billing Demand will be applied to the above charges if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.

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Monthly Minimum Charge	50% of the highest Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding 11 Billing Periods. For the purpose of this provision an on-peak period commences on November 1 in any year and terminates on March 31 of the following year.
Rate Schedules	1. Rate Schedule 1500: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1501: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1510: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1511: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Definitions	1. Billing Demand The Billing Demand will be the highest kW Demand in the Billing Period. 2. Billing Period A month between regular meter readings, provided that in cases where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period.

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Special Conditions	1. Metering Metering Equipment with both Demand and Energy measurement capability will normally be installed. Until such Metering Equipment is installed, or if the installed Metering Equipment does not have Demand measurement capability, Billing Demand will be as estimated by BC Hydro 2. Migration Rules 2.1. Migration rules from Medium General Service: Customers taking Service under these Rate Schedules (Medium General Service) will be moved to Service: (a) Under Rate Schedules 1300, 1301, 1310 or 1311 (Small General Service) if Billing Demand in each of the last 12 consecutive Billing Periods was less than 35 kW. (b) Under Rate Schedules 1600, 1601, 1610 or 1611 (Large General Service) if Billing Demand in half of the last 12 Billing Periods was 150 kW or more, or if total Energy consumption in any 12 consecutive month period exceeded 550,000 kWh.

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	2.2. Migration rules to Medium General Service: Customers will be moved to Service under these Rate Schedules (Medium General Service): (a) From Rate Schedules 1600, 1601, 1610 or 1611 (Large General Service) if Billing Demand in each of the last 12 Billing Periods was 35 kW or more, but less than 100 kW, and Energy consumption during the same period was less than 400,000 kWh. (b) From Rate Schedules 1300, 1301, 1310 or 1311 (Small General Service) if Billing Demand in half of the last six bi-monthly Billing Periods or half of the last 12 monthly Billing Periods (as applicable) was 35 kW or more, but less than 150 kW, and total Energy consumption in the same period was less than 550,000 kWh.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under these Rate Schedules include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under these Rate Schedules include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

2. GENERAL SERVICE

RATE SCHEDULES 1600, 1601, 1610, 1611 – LARGE GENERAL SERVICE (150 KW AND OVER)

Availability	For Customers who qualify for General Service and whose Billing Demand is equal to or greater than 150 kW, or whose Energy consumption in any 12 month period is greater than 550,000 kWh. Supply is 60 hertz, single or three phase at Secondary or Primary Voltage. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone I.
Rate	**Basic Charge:** 26.73~~25.02~~ ¢ per day plus **Demand Charge:** $12.34~~11.55~~ per kW of Billing Demand plus **Energy Charge:** 6.06~~5.67~~ ¢ per kWh
Discounts	1. A discount of 1½% will be applied to the above charges if a Customer's supply of Electricity is metered at a Primary Voltage. 2. A discount of 25 ¢ per Billing Period per kW of Billing Demand will be applied to the above charges if a Customer supplies Transformation. 3. If a Customer is entitled to both of the above discounts, the discount for metering at a Primary Voltage will be applied first.

ACCEPTED:_________________________

ORDER NO._________________________

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COMMISSION SECRETARY

Monthly Minimum Charge	50% of the highest Demand Charge billed in any Billing Period wholly within an on-peak period during the immediately preceding 11 Billing Periods. For the purpose of this provision an on-peak period commences on November 1 in any year and terminates on March 31 of the following year.
Rate Schedules	1. Rate Schedule 1600: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and BC Hydro supplies Transformation. 2. Rate Schedule 1601: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and BC Hydro supplies Transformation. 3. Rate Schedule 1610: Applies if a Customer's supply of Electricity is metered at a Secondary Voltage and the Customer supplies Transformation. 4. Rate Schedule 1611: Applies if a Customer's supply of Electricity is metered at a Primary Voltage and the Customer supplies Transformation.
Definitions	1. Billing Demand The Billing Demand will be the highest kW Demand in the Billing Period. 2. Billing Period A month between regular meter readings, provided that where meter readings are not available or are delayed for any reason BC Hydro may vary the number of days in the Billing Period.

Special Conditions	1. Metering Metering Equipment with both Demand and Energy measurement capability will normally be installed. Until such Metering Equipment is installed, or if the installed Metering Equipment does not have Demand measurement capability, Billing Demand will be as estimated by BC Hydro. 2. Migration Rules 2.1. Migration rules from Large General Service: Customers taking Service under these Rate Schedules (Large General Service) will be moved to Service: (a) Under Rate Schedules 1300, 1301, 1310 or 1311 (Small General Service) if Billing Demand in each of the last 12 consecutive Billing Periods was less than 35 kW. (b) Under Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) if Billing Demand in each of the last 12 consecutive Billing Periods was 35 kW or more but less than 100 kW, and Energy consumption in the same period was less than 400,000 kWh. 2.2. Migration rules to Large General Service: Customers will be moved to Service under these Rate Schedules (Large General Service) from Rate Schedules 1300, 1301, 1310 or 1311 (Small General Service) or Rate Schedules 1500, 1501, 1510 or 1511 (Medium General Service) if Billing Demand in half of the last six bi-monthly Billing Periods or half of the last 12 monthly Billing Periods (as applicable) was 150 kW or more, or if total Energy consumption in any 12 consecutive month period exceeded 550,000 kWh.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under these Rate Schedules, before taxes and levies.

Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under these Rate Schedules include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under these Rate Schedules include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:______________________________

ORDER NO.______________________________

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3. IRRIGATION SERVICE

RATE SCHEDULE 1401 – IRRIGATION SERVICE

Availability	For motor loads of 746 watts or more used for irrigation and outdoor sprinkling where Electricity will be used principally during the Irrigation Season as defined below. Supply is 60 hertz, single or three phase at the Secondary or Primary Voltage available. BC Hydro reserves the right to determine the voltage of the Service Connection.
Applicable in	Rate Zone I and Rate Zone IB.
Rate	1. During the Irrigation Season: **Energy Charge:** 6.12~~5.73~~ ¢ per kWh **Minimum Charge:** $6.12~~5.73~~ per kilowatt of connected load per month for a period of eight months commencing in March in any year whether Energy consumption is registered or not. 2. During the Non-Irrigation Season: **Energy Charge:** First 150 kWh @ 6.12~~5.73~~ ¢ per kWh All additional kWh @ 48.52~~45.41~~ ¢ per kWh **Minimum Charge:** Where Energy consumption is 500 kWh or less, Nil. Where Energy consumption is more than 500 kWh, $48.94~~45.80~~ per kilowatt of connected load.
Discount for Ownership of Transformers	A discount of 25 ¢ per month per kW of connected load will be applied to the above charges if a Customer supplies the Transformation.

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Definitions	1. Irrigation Season: In respect of each Service Connection the period commencing with a meter reading on or about March 1 in any year, having a mid-season meter reading on or about July 31, and ending with a meter reading on or about October 31 in that same year. BC Hydro may, in its discretion extend such period by postponing the termination date to any date not later than November 30, for the sole purpose of permitting a Customer to fill reservoirs necessary for the operation of the irrigation or sprinkling system. 2. Non-Irrigation Season: The period commencing at the end of one Irrigation Season and terminating at the beginning of the next Irrigation Season.
Special Conditions	1. No equipment provided with Electricity under this Rate Schedule will be served with Electricity under any other Rate Schedule while the Customer's Service Agreement under this Rate Schedule is in force. 2. Normally the Service Connection will be energized during the Non-Irrigation Season, but will be Disconnected if a Customer so requests. 3. The Minimum Charge during the Irrigation Season will commence in March for an account that has not been Terminated by the Customer, whether or not the Service Connection is energized and will be billed in two installments, at the end of July and at the end of October. 4. For the Irrigation Season, a bill will be rendered following the July and October meter readings. The first bill will be the greater of the Energy Charge and the Minimum Charge for the period March 1 to July 31. The second bill will be the greater of the Energy Charge for the season and the Minimum Charge for the season, less payment received for the first billing charges.

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	5. For the Non-Irrigation Season a bill will be rendered following the March meter reading provided that there is registered Energy consumption. 6. If a motor is rated in horsepower, the conversion factor from horsepower to kilowatts will be: 1 horsepower = 0.746 kilowatts
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under this Rate Schedule include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under this Rate Schedule include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:____________________________

ORDER NO.____________________________

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COMMISSION SECRETARY

4. STREET LIGHTING SERVICE

RATE SCHEDULE 1701 – OVERHEAD STREET LIGHTING

Availability	For lighting of public highways, streets and lanes in cases where BC Hydro owns, installs and maintains the fixtures, conductors, controls and poles.
Applicable in	Any area served by suitable overhead distribution lines.
Rate	Per fixture per month as set out below: 100 watt H.P. sodium vapour unit $19.60~~18.34~~ 150 watt H.P. sodium vapour unit $23.38~~21.88~~ 200 watt H.P. sodium vapour unit $26.99~~25.26~~ *175 watt mercury vapour unit $21.54~~20.16~~ *250 watt mercury vapour unit $24.82~~23.23~~ *400 watt mercury vapour unit $31.99~~29.94~~ Wattages are lamp watts. * Note Special Condition No. 2.
Special Conditions	1. Connection Charge No charge will be made for Service Connections. 2. Mercury Vapour Mercury vapour fixtures are not available for new installations.

ACCEPTED:______________________

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	3. Extension Policy BC Hydro will construct a distribution Extension if required by the applicant in accordance with the Terms and Conditions of the Electric Tariff as applicable. When, at the Customer's request, a new fixture replaces an existing fixture, the Customer will pay to BC Hydro the original cost of the existing fixture, less any accumulated depreciation, and the cost of removing the existing fixture. 4. Relocation and Redirection of Fixtures The Customer will pay the full cost of relocating or redirecting fixtures when the change is made at the request of the Customer. 5. Design BC Hydro will design the installation of overhead street lighting fixtures. 6. Lamps Failing to Operate BC Hydro will, without charge, replace lamps or components that fail to operate, unless breakage is the reason for such failure in which case the Customer will be charged the cost of the material required to make the fixture operate. 7. Term of Service Agreement The term of the initial Service Agreement under this Rate Schedule will be not more than five years; renewal periods will be for five years.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

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Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under this Rate Schedule include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under this Rate Schedule include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:____________________________

ORDER NO.____________________________

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4. STREET LIGHTING SERVICE

RATE SCHEDULE 1702 – PUBLIC AREA ORNAMENTAL STREET LIGHTING

Availability	For lighting of public highways, streets and lanes and municipal pathways and for public area seasonal lighting displays, in those cases where the Customer owns, installs and maintains the standards, fixtures, conductors and controls.
Applicable in	All Rate Zones.
Rate	**Energy Charge:** For each unmetered fixture: 3.77~~3.53~~ ¢ per watt of Billing Wattage per month For each metered fixture: 11.32~~10.59~~ ¢ per kWh
Definitions	Billable Wattage is the sum of all wattage, on all fixtures used by the Customer. For fixtures without dimming controls, the watts per fixture will include the wattage of the lamp plus, where applicable, the wattage of the ballast. For fixtures with dimming controls, the watts per fixture will be equal to: 1. The wattage of the lamp plus, where applicable, the wattage of the ballast, multiplied by 2. The ratio of effective fixture wattage after dimming to fixture wattage before dimming.

Special Conditions	1. Service Connection Where necessary BC Hydro will provide an overhead or underground Service Connection in accordance with the Terms and Conditions of the Electric Tariff. No Service Connection will be made to add any ornamental street lighting system which does not provide for eight or more street lighting fixtures except that, if the potential is 120/240 volts, at BC Hydro's discretion, a Service Connection may be made for a system of less than eight. Receptacle loads will be permitted for Service under this Rate Schedule provided that such receptacles are used predominantly for seasonal lighting displays, meaning that no more than 10% of the usage may be for other purposes. 2. Extension Policy BC Hydro will construct a distribution Extension if required by the applicant in accordance with the Terms and Conditions of the Electric Tariff. 3. Power Factor All installations of mercury vapour, sodium vapour or fluorescent lamps will be equipped with the necessary auxiliaries to assure that a Power Factor of not less than 90% lagging will be maintained. 4. Term of Service Agreement The term of the initial Service Agreement under this Rate Schedule will be not more than five years; renewal periods will be for five years.

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	5. Fixtures with Automated Dimming Controls The following special terms and conditions apply to lighting fixtures fitted with dimming controls: (a) For purposes of this Special Condition No. 5, “dimming controls” means control units or fittings attached to, or forming part of, a street lighting fixture capable of being programmed or remotely operated so as to reduce the lumens output of the lamps during specified hours each day while the lamps are in operation. The reductions may vary according to the hours of the day, the days of the week, and the seasons of the year. (b) A Customer wishing to have fixtures with dimming controls separately rated under this Rate Schedule must submit a dimming schedule satisfactory to BC Hydro listing each light fixture fitted with dimming controls, the wattage of the fixture (including the lamp and, where applicable, the ballast), the dimming control setting or settings and the hours each day that the dimming control setting or settings will be in operation. (c) Whenever the Customer wishes to make changes in the lighting fixtures listed in the dimming schedule or in the dimming control settings or hours of operation, the Customer will submit an updated lighting fixture schedule to BC Hydro listing any changes. Changes will be permitted on a semi-annual basis (twice per year).

	6. Unmetered Service (a) BC Hydro may permit unmetered Service under this Rate Schedule if it can estimate to its satisfaction the Energy used in kilowatt hours over a period of one month based on the connected load and hours of use. (b) The Customer will notify BC Hydro immediately of any proposed or actual change in load, or load characteristics, or hours of use. (c) BC Hydro, in its discretion, may at any time install Metering Equipment and thereafter bill the Customer on the Energy consumption registered.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under this Rate Schedule include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under this Rate Schedule include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:______________________________

ORDER NO.______________________________ ______________________________
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4. STREET LIGHTING SERVICE

RATE SCHEDULE 1703 – STREET LIGHTING SERVICE

Availability	For lighting of public highways, streets and lanes in those cases where the Customer owns, installs and maintains the fixtures, conductors and controls on poles of BC Hydro. Available only to Customers formerly taking Service on Rate Schedule 1755, 1756, 1757, 1758, 1759 or 1767, to the City of New Westminster in respect of a portion of D.L. 172, to the Municipality of Sparwood and to the City of Vancouver.
Applicable in	The Cities of Victoria and Prince Rupert, the Municipalities of Oak Bay, Esquimalt, Saanich and Central Saanich, the Village of Sidney, the unorganized areas of Port Renfrew and Shawnigan Lake, a portion of D.L. 172 in the City of New Westminster, Natal and the City of Vancouver.
Rate	**Energy Charge:** 3.77~~3.53~~ ¢ per watt of Billing Wattage per month plus **Contact Charge:** $1.13~~1.06~~ per contact per month The Contact Charge is a per fixture charge for the use of pole space.
Definitions	Billable Wattage is the sum of all wattage, on all fixtures used by the Customer. For fixtures without dimming controls, the watts per fixture will include the wattage of the lamp plus, where applicable, the wattage of the ballast. For fixtures with dimming controls, the watts per fixture will be equal to: 1. The wattage of the lamp plus, where applicable, the wattage of the ballast, multiplied by 2. The ratio of effective fixture wattage after dimming to fixture wattage before dimming.

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Special Conditions	1. Extension Policy No Extension will be made to provide Service to street lights under this Rate Schedule. 2. Power Factor All installations of mercury vapour, sodium vapour or fluorescent lamps will be equipped with the necessary auxiliaries to assure that a Power Factor of not less than 90% lagging will be maintained. 3. Term of Service Agreement The term of the initial Service Agreement under this Rate Schedule will be not more than five years; renewal periods will be for five years. 4. Fixtures with Automated Dimming Controls The following special terms and conditions apply to lighting fixtures fitted with dimming controls: (a) For purposes of this Special Condition No. 4, "dimming controls" means control units or fittings attached to, or forming part of, a street lighting fixture capable of being programmed or remotely operated so as to reduce the lumens output of the lamps during specified hours each day while the lamps are in operation. The reductions may vary according to the hours of the day, the days of the week, and the seasons of the year. (b) A Customer wishing to have fixtures with dimming controls separately rated under this Rate Schedule must submit a dimming schedule satisfactory to BC Hydro listing each light fixture fitted with dimming controls, the wattage of the fixture (including the lamp and, where applicable, the ballast), the dimming control setting or settings and the hours each day that the dimming control setting or settings will be in operation.

	(c) Whenever the Customer wishes to make changes in the lighting fixtures listed in the dimming schedule or in the dimming control settings or hours of operation, the Customer will submit an updated lighting fixture schedule to BC Hydro listing any changes. Changes will be permitted on a semi-annual basis (twice per year).
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under this Rate Schedule include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under this Rate Schedule include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:______________________________

ORDER NO.______________________________

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4. STREET LIGHTING SERVICE

RATE SCHEDULE 1704 – TRAFFIC CONTROL EQUIPMENT

Availability	For lighting of traffic signals, traffic signs and traffic warning devices, and other equipment for controlling or directing vehicular or pedestrian traffic on public highways in those cases where the Customer owns, installs, and maintains the standards, fixtures, controls and associated equipment.
Applicable in	All Rate Zones.
Rate	**Energy Charge:** 11.32~~10.59~~ ¢ per kWh
Special Conditions	1. Service Connections Where necessary BC Hydro will provide an overhead or underground Service Connection in accordance with section 3 of the Terms and Conditions (Provision of Electricity). 2. Unmetered Service (a) BC Hydro may permit unmetered Service under this Rate Schedule if it can estimate to its satisfaction the Energy used in kilowatt hours over a period of one month based on the connected load and hours of use. (b) The Customer shall notify BC Hydro immediately of any proposed or actual change in load, or load characteristics, or hours of use. (c) BC Hydro, in its discretion, may at any time install a meter or meters and thereafter bill the Customer on the consumption registered.

ACCEPTED:____________________

ORDER NO.____________________

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	3. Term of Service Agreement The term of the initial Service Agreement under this Rate Schedule will be not more than five years; renewal periods will be for five years.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rate under this Rate Schedule include~~s~~~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rate under this Rate Schedule includes an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:______________________________

ORDER NO.______________________________

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4. STREET LIGHTING SERVICE

RATE SCHEDULE 1755 – PRIVATE OUTDOOR LIGHTING (CLOSED)

Availability	For outdoor lighting Service to illuminate property other than public streets or lanes (private property), where Service is provided from dusk to dawn and the supply is single phase, 60 hertz at the Secondary Voltage available. This Rate Schedule is available only in Premises served under this Rate Schedule on January 1, 1975 and only with respect to lights served under this Rate Schedule on January 1, 1975 and continuously thereafter, except BC Hydro may replace a mercury vapour unit with a high pressure sodium unit having approximately the same equivalent light output.
Applicable in	All Rate Zones.
Rate	**Charge per fixture per month as follows:** 1. Where a light is mounted on a pole that was installed by the Customer or by BC Hydro at the Customer's expense: 175 watt mercury vapour unit or replacement 100 watt H.P. sodium vapour unit — $18.37~~17.19~~ 400 watt mercury vapour unit or replacement 150 watt H.P. sodium vapour unit — $31.66~~29.63~~

ACCEPTED:______________________

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	2. Where a light is mounted on a pole that is on public property, or an easement, and is part of BC Hydro's distribution system: 175 watt mercury vapour unit or replacement 100 watt H.P. sodium vapour unit — $19.51~~18.26~~ 400 watt mercury vapour unit or replacement 150 watt H.P. sodium vapour unit — $32.81~~30.71~~ 3. Where a light is mounted on a pole that was installed on the Customer's property by BC Hydro, at its expense, solely for the purpose of supporting the light: 175 watt mercury vapour unit or replacement 100 watt H.P. sodium vapour unit — $24.02~~22.48~~ 400 watt mercury vapour unit or replacement 150 watt H.P. sodium vapour unit — $37.81~~35.39~~ Except that if two or more lights are mounted at one time on the same pole the rates for the additional light or lights will be as set out under part 1 above.
Special Conditions	1. BC Hydro will provide and install: (a) An outdoor light consisting of luminaire, mast arm, ballast, lamp and photo-electric control, and (b) Not more than one span of overhead secondary conductors per light. 2. The Customer will be required to contribute the estimated cost of any plant required to make Secondary Voltage available at a point not more than one span from the light; such contribution is not subject to refund.

	3. BC Hydro reserves the sole right to determine whether or not a light will be installed on a pole that is part of BC Hydro's distribution system. 4. The prior approval of BC Hydro is required if a Customer intends to install its own poles, and such poles will be maintained to BC Hydro's satisfaction at the Customer's expense. 5. BC Hydro will maintain all equipment owned by BC Hydro and will replace lamps which have failed. Any breakage will be repaired by BC Hydro at the Customer's expense.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under this Rate Schedule include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under this Rate Schedule include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:____________________________

ORDER NO.____________________________

COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1823 – TRANSMISSION SERVICE – STEPPED RATE

Availability	For all purposes. Supply is at 60 kV or higher. Customers supplied with Electricity under Rate Schedule 1825 (Time-of-Use) may only revert to Service under this Rate Schedule as permitted under Rate Schedule 1825.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Demand Charge:** $8.697~~8.139~~ per kVA of Billing Demand per Billing Period plus **Energy Charge: A** For new Customers and Customers that do not have a CBL by order of the British Columbia Utilities Commission: 5.098~~4.771~~ ¢ per kWh for all kWh per Billing Period This rate will apply until the Customer has been supplied with Electricity under this Rate Schedule for 12 Billing Periods or another period approved by the British Columbia Utilities Commission, after which the Customer will be supplied with Electricity at the rate specified in Part B below.

ACCEPTED:______________________

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	Energy Charge: B For Customers with a CBL: 4.535~~4.244~~ ¢ per kWh applied to all kWh up to and including 90% of the Customer's CBL in each Billing Year 10.160~~9.509~~ ¢ per kWh applied to all kWh above 90% of the Customer's CBL in each Billing Year Note: Customers previously supplied with Electricity under Rate Schedule 1825 will be subject to the rates in Part B above from the time the Customer commences taking Service under this Rate Schedule. **Monthly Minimum Charge:** $8.697~~8.139~~ per kVA of Billing Demand
Definitions	1. Billing Year The Billing Year is the 12 month billing period starting with the first day of the Billing Period which commences nearest to April 1 in each year, and ending on the last day of such 12-month Billing Period. 2. Billing Demand The Billing Demand will be: (a) The highest kVA Demand during the High Load Hours (**HLH**) in the Billing Period; or (b) 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or (c) 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant, whichever is the highest value, provided that for new Customers the Billing Demand for the initial two Billing Periods will be the average of the daily highest kVA Demands for the Customer's Plant.

ACCEPTED:______________________

ORDER NO.______________________

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	3. Customer Baseline Load (**CBL**) The Customer Baseline Load (**CBL**) is the Customer's historic annual energy consumption in kWh as approved by the British Columbia Utilities Commission. The Customer’s CBL will initially be determined by BC Hydro, and be subject to revision from time to time, in accordance with the criteria and procedures set forth in BC Hydro's "Customer Baseline Load (**CBL**) Determination Guidelines" (Electric Tariff Supplement No. 74). All CBLs will be subject to final approval of the British Columbia Utilities Commission. 4. High Load Hours (**HLH**) High Load Hours (**HLH**) is the period of hours from 06:00 to 22:00 Monday to Saturday, except for Statutory Holidays (New Year’s Day, Family Day, Good Friday, Victoria Day, Canada Day, B.C. Day, Labour Day, Thanksgiving Day, Remembrance Day and Christmas Day). 5. Low Load Hours (**LLH**) Low Load Hours (**LLH**) are all hours other than HLH.
Special Conditions	1. A Customer having two or more operating plants may elect to have a single aggregated CBL determined for all or any combination of its operating plants in accordance with BC Hydro’s “Customer Baseline Load (**CBL**) Determination Guidelines” (Electric Tariff Supplement No. 74). Thereafter, BC Hydro will issue a single bill for all operating plants included in the aggregation, and the Energy Charge payable will be determined on the basis of the aggregated CBL. However, the Demand Charge will continue to be determined separately for each operating plant.

	2. If any initial, revised, or aggregate CBL for a Customer has not been determined by BC Hydro and approved by British Columbia Utilities Commission by the time at which the CBL would become effective, BC Hydro may determine the CBL on an interim basis and apply that CBL for the purposes of any billing periods and bills rendered to the Customer until such time as the CBL has been finally determined and approved by the British Columbia Utilities Commission, following which BC Hydro will make any necessary billing adjustments. 3. If a Customer taking Service at the rates in Part B of the Energy Charge rate section above Terminates Service under this Rate Schedule prior to the end of a Billing Year, the Customer's CBL or aggregate CBL will be prorated for the portion of the Billing Year during which the Customer was taking Service, and the prorated CBL or aggregate CBL will be used for the purposes of applying the rates in Part B to all energy consumption during the Billing Year up to the time of Termination. BC Hydro will make any necessary billing adjustments and bill the Customer for the difference (if any) owing.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Note	The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement Nos. 5 and 6, or Electric Tariff Supplement Nos. 87 and 88, as applicable.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

ACCEPTED:________________________

ORDER NO.________________________ ____________________________

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Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under this Rate Schedule include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under this Rate Schedule include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:____________________________

ORDER NO.____________________________

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COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1825 – TRANSMISSION SERVICE – TIME-OF-USE (TOU) RATE

Availability	For Customers who provide notice by February 15 of each year and who at the time of application are eligible to take Service under Rate Schedule 1823 (Stepped Rate) at the Energy Charge rates set out in Part B of the rate section of that Rate Schedule, and who have entered into a TOU (Transmission Service) Agreement by March 15 of that year. Customers will start Service under Rate Schedule 1825 in the first Billing Period after April 1.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Demand Charge:** $8.697~~8.139~~ per kVA of Billing Demand per Billing Period plus **Energy Charge:** 1. Winter HLH Period: 4.535~~4.244~~ ¢ per kWh applied to all kWh up to and including 90% of the Customer's Winter HLH Period CBL. 11.337~~10.611~~ ¢ per kWh applied to all kWh above 90% of the Customer's Winter HLH Period CBL. 2. Winter LLH Period: 4.535~~4.244~~ ¢ per kWh applied to all kWh up to and including 90% of the Customer's Winter LLH Period CBL. 10.275~~9.616~~ ¢ per kWh applied to all kWh above 90% of the Customer's Winter LLH Period CBL.

ACCEPTED:_____________________________

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	3. Spring Period: 4.535~~4.244~~ ¢ per kWh applied to all kWh up to and including 90% of the Customer's Spring Period CBL. 9.151~~8.565~~ ¢ per kWh applied to all kWh above 90% of the Customer's Spring Period CBL. 4. Remaining Period: 4.535~~4.244~~ ¢ per kWh applied to all kWh up to and including 90% of the Customer's Remaining Period CBL applicable. 10.035~~9.392~~ ¢ per kWh applied to all kWh above 90% of the Customer's Energy CBL applicable in the Billing Period.
Definitions	1. Billing Demand The Demand for billing purposes will be: (a) The highest kVA Demand during the High Load Hours (**HLH**) in the Billing Period; or (b) 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or (c) 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant, whichever is the highest value.

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	2. Customer Baseline Load (CBL) The Customer Baseline Load (**CBL**) is the Customer's historic consumption (in kWh) as approved by the British Columbia Utilities Commission. For the purposes of this Rate Schedule, the Customer's CBL will consist of four separate CBLs – one each for the Winter HLH Period, the Winter LLH Period, the Spring Period and the Remaining Period. The Customer's CBL will initially be determined by BC Hydro, and be subject to revision from time to time, in accordance with the criteria and procedures set forth in BC Hydro's "Customer Baseline Load (**CBL**) Determination Guidelines" (Electric Tariff Supplement No. 74). All CBLs will be subject to final approval of the British Columbia Utilities Commission. 3. High Load Hours (**HLH**) High Load Hours (**HLH**) is the period of hours from 06:00 to 22:00 Monday to Saturday, except for Statutory Holidays (New Year's Day, Family Day, Good Friday, Victoria Day, Canada Day, B.C. Day, Labour Day, Thanksgiving Day, Remembrance Day and Christmas Day). 4. Low Load Hours (**LLH**) The Low Load Hours (**LLH**) are all hours other than HLH. 5. Remaining Period The Remaining Period is all Billing Periods other than the Winter Period or the Spring Period. 6. Spring Period The Spring Period comprises the two Billing Periods starting with the first day of the Billing Period that commences nearest to May 1 each year and ending on the last day of the second Billing Period thereafter.

	7. Winter Period The Winter Period comprises four Billing Periods starting with the first day of the Billing Period that commences nearest to November 1 each year and ending on the last day of the fourth Billing Period thereafter.
Special Conditions	1. Service under this Rate Schedule will be provided only while a TOU (Transmission Service) Agreement with the Customer is in effect. 2. A Customer having two or more operating plants may elect to have a single aggregated CBL determined for all or any combination of its operating plants in accordance with BC Hydro's "Customer Baseline Load (CBL) Determination Guidelines" (Electric Tariff Supplement No. 74). Separate Energy CBL values will be determined for each plant and then aggregated. BC Hydro will issue a single bill for all operating plants included in an aggregation, and the Energy Charge payable will be determined on the basis of the aggregated Energy CBL value. The Demand Charge will continue to be determined separately for each operating plant. 3. If any initial, revised, or aggregate CBL for a Customer has not been determined by BC Hydro and approved by British Columbia Utilities Commission by the time at which the CBL would become effective, BC Hydro may determine the CBL on an interim basis and apply that CBL for the purposes of any billing periods and bills rendered to the Customer until such time as the CBL has been finally determined and approved by the British Columbia Utilities Commission, following which BC Hydro will make any necessary billing adjustments.

ACCEPTED:____________________

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	4. In accordance with the TOU (Transmission Service) Agreement, the Customer will have a period of 30 days following approval of the Customer's initial CBL by the British Columbia Utilities Commission within which the Customer may, by written notice to BC Hydro, withdraw from taking Service under this Rate Schedule, and revert to taking Service under Rate Schedule 1823 (Stepped Rate). This right of withdrawal is available only when the Customer first subscribes to take Service under this Rate Schedule, and is applicable only in respect of the initial CBL determination. If the Customer exercises this right of withdrawal Rate Schedule 1823 will apply from the commencement of the then current Billing Year, and BC Hydro will make any necessary billing adjustments accordingly. 5. Customers taking Service under Rate Schedule 1852 (Modified Demand) may not also take Service under this Rate Schedule.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Note	The terms and conditions under which Transmission Service is supplied are contained in the Electricity Supply Agreement (Electric Tariff Supplement No. 5, or Electric Tariff Supplement No. 87, as applicable) as amended by the Electric Tariff Supplement No. 72 (TOU (Transmission Service) Agreement), and Electric Tariff Supplement No. 6, or Electric Tariff Supplement No. 88, as applicable.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under this Rate Schedule include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under this Rate Schedule include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:______________________

ORDER NO.______________________

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COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1827 – TRANSMISSION SERVICE – RATE FOR EXEMPT CUSTOMERS

Availability	For all purposes. Supply is at 60 kV or higher. Only for City of New Westminster and University of British Columbia and other Customers exempted from Rate Schedule 1823 (Stepped Rate) by the British Columbia Utilities Commission.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Demand Charge:** $8.697~~8.139~~ per kVA of Billing Demand per Billing Period plus **Energy Charge:** 5.098~~4.771~~ ¢ per kWh for all kWh in a Billing Period **Monthly Minimum Charge:** $8.697~~8.139~~ per kVA of Billing Demand
Definitions	1. Billing Demand The Billing Demand will be: (a) The highest kVA Demand during the High Load Hours (**HLH**) in the Billing Period; or (b) 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or (c) 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant, whichever is the highest value.

ACCEPTED:____________________

ORDER NO.____________________

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	2. High Load Hours (**HLH**) High Load Hours (**HLH**) is the period of hours from 06:00 to 22:00 Monday to Saturday, except for Statutory Holidays (New Year's Day, Family Day, Good Friday, Victoria Day, Canada Day, B.C. Day, Labour Day, Thanksgiving Day, Remembrance Day and Christmas Day). 3. Low Load Hours (**LLH**) Low Load Hours (**LLH**) are all hours other than HLH.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Note	The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement Nos. 5 and 6, or Electric Tariff Supplements Nos. 87 and 88, as applicable.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rates under this Rate Schedule include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rates under this Rate Schedule include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

5. TRANSMISSION SERVICE

RATE SCHEDULE 1852 – TRANSMISSION SERVICE – MODIFIED DEMAND

Availability	To a Customer supplied with Electricity at 60 kV or higher who is taking Service under Rate Schedule 1823 (Stepped Rate) at the time of application, and is a party to a Modified Demand Agreement under Electric Tariff Supplement No. 54 which is in force, and which is in a location, as determined by BC Hydro, that will allow BC Hydro to curtail load to alleviate a potential local or regional transmission constraint, or take advantage of a market opportunity. The annual subscription period for new subscribers is from September 1 to October 31.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Excess Demand Charge:** $8.697~~8.139~~ per kVA of metered kVA Demand in excess of the Maximum Demand Level during Low Load Hours
Definitions	1. Billing Demand The Billing Demand will be: (a) The highest kVA Demand during the High Load Hours (**HLH**) in the Billing Period; or (b) 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or (c) 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant, whichever is the highest value.

	2. High Load Hours (**HLH**) High Load Hours (**HLH**) means the period(s) in a 24-hour day and during those days of a calendar week in which Electricity usage is typically highest in a particular region, as determined by BC Hydro in its discretion based on load characteristics and transmission constraints in that region from time to time, and designated in a Modified Demand Agreement. 3. Low Load Hours (**LLH**) Low Load Hours (**LLH**) are all hours other than HLH. 4. LLH CBL Energy LLH CBL Energy means the highest monthly energy consumption during the LLH over the last 12 Billing Periods, or an estimate of consumption if insufficient data is available. 5. Maximum Demand Level Maximum Demand Level has the meaning set out in the Modified Demand Agreement. For a Customer with more than one designated period of High Load Hours, separate Maximum Demand Levels will be stated for each corresponding period of Low Load Hours. For a Customer with a single designated period of High Load Hours, a single Maximum Demand Level will be stated for all Low Load Hours. The highest Maximum Demand Level will not exceed 95% of Contract Demand stated in the Customer's Electricity Supply Agreement, and is subject to local transmission availability.

ACCEPTED:______________________________

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Special Conditions	1. The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement Nos. 5 and 6. The provisions of Rate Schedule 1823 (Stepped Rate) and Electric Tariff Supplement Nos. 5 and 6 continue to apply to Customers receiving Service under this Rate Schedule. In the case of a conflict between this Rate Schedule or the Modified Demand Agreement and Rate Schedule 1823 or Electric Tariff Supplement Nos. 5 or 6, the provisions of this Rate Schedule and the Modified Demand Agreement will govern. 2. If for any two Billing Periods the total energy consumed under Rate Schedule 1852, during the LLH, is greater than the LLH CBL Energy by 10% or more, the highest kVA Demand in each such Billing Period during the High Load Hours will be adjusted by the ratio of the average monthly LLH Energy during such two Billing Periods over the LLH CBL Energy. The adjusted highest kVA Demand will apply for a period of 12 months after the second Billing Period included in the adjustment calculation. The LLH CBL Energy will be recalculated using the consumption history of the most recent 12 Billing Periods. 3. The Minimum Reduction under the Modified Demand Agreement will be the greater of 50% of the difference between the Maximum Demand Level and the LLH CBL Demand, and 10 MW. 4. The Maximum Number of Demand Reduction Transactions under the Modified Demand Agreement will be the greater of Maximum Duration multiplied by the Maximum Number of Demand Reduction Transactions, and 48 hours.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the rate under this Rate Schedule includes~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the rate under this Rate Schedule includes an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:_________________________

ORDER NO._________________________

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5. TRANSMISSION SERVICE

RATE SCHEDULE 1853 – TRANSMISSION SERVICE – IPP STATION SERVICE

Availability	For Customers who are Independent Power Producers (**IPPs**) served at transmission voltage, on an interruptible basis.
Applicable in	Rate Zone I excluding Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Energy Charge:** The sum, over the Billing Period, of the hourly energy consumed multiplied by the entry in the Intercontinental Exchange (**ICE**) Mid-Columbia (Mid-C) Peak, and Mid-C Off-Peak weighted average index price as published by the ICE in the ICE Day Ahead Power Price Report that corresponds to the time when consumption occurred, during that hour
Monthly Minimum Charge	$49.01~~45.87~~
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. 2. BC Hydro may, without notice to the Customer, refuse to supply or terminate the supply of Electricity under this Rate Schedule if at any time BC Hydro does not have sufficient energy or capacity. 3. Prior to taking Electricity under this Rate Schedule, the Customer may be required to obtain approval from BC Hydro. BC Hydro will advise the Customer of the need to obtain approval prior to the taking of Electricity under this Rate Schedule. 4. Electricity taken under this Rate Schedule is to be used solely for maintenance and black-start requirements and will not displace electricity that would normally be generated by the Customer.

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Taxes	The rates and Monthly Minimum Charge set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the Monthly Minimum Charge under this Rate Schedule includes~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the Monthly Minimum Charge under this Rate Schedule includes an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

5. TRANSMISSION SERVICE

RATE SCHEDULE 1880 – TRANSMISSION SERVICE – STANDBY AND MAINTENANCE SUPPLY

Availability	For Customers supplied with Electricity under Rate Schedule 1823 (Stepped Rate), 1825 (TOU Rate), 1827 (Rate for Exempt Customers) or 1852 (Modified Demand), on an interruptible basis.
Applicable in	Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.
Rate	**Administrative Charge:** \$150.00 per Period of Use plus **Energy Charge:** During the Period of Use, 10.160~~9.509~~ ¢ per kWh of metered Rate Schedule 1880 energy consumption, determined as set out below
Definitions	1. HLH Reference Demand HLH Reference Demand is the highest kVA Demand in the HLH for the current Billing Period prior to the Period of Use, but excluding any prior Period of Use. If the Period of Use extends over an entire Billing Period, the highest kVA Demand in the HLH from the prior Billing Period will be used in determining the HLH Reference Demand, excluding any Period of Use in the prior Billing Period. For the purpose of determining HLH Reference Demand, the HLH periods are as defined in Rate Schedule 1823, 1825, 1827 or 1852, whichever is applicable.

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	2. Period of Use A period of consecutive hours during which Electricity is taken under this Rate Schedule. The Period of Use is as defined by the Customer when requesting Service from BC Hydro under this Rate Schedule 1880 and may extend into subsequent Billing Periods.
Rate Schedule 1880 Energy Determination	During HLH periods, the kWh consumption on an hourly basis which exceeds the HLH high kWh per hour within the Period of Use or portion thereof where HLH high kWh per hour is the product of HLH Reference Demand multiplied by the Power Factor for the half hour when the HLH Reference Demand occurred. For the purpose of the Rate Schedule 1880 Energy Determination, the HLH periods are as defined in Rate Schedule 1823, 1825, 1827 or 1852, whichever is applicable.
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. 2. BC Hydro may, without notice to the Customer, refuse to supply or terminate the supply of Electricity under this Rate Schedule if at any time during the Period of Use BC Hydro does not have sufficient energy or capacity.

	3. This Rate Schedule is only for the following purposes: To provide Electricity the Customer would otherwise generate during periods when all or part of the Customer's electrical generating plant is curtailed. Electricity used for this purpose may be taken on an instantaneous basis when the impact of the instantaneous pickup of loads normally provided by the Customer's electrical generation units does not occur after BC Hydro has advised the Customer that a period of system constraint or potential system constraint exists. During periods of potential system constraints, BC Hydro will require Customers to arm load shedding relays to ensure that the loss of electricity production from a Customer's electrical generation unit will not result in a demand greater than the Customer's Maximum kVA Demand on BC Hydro's system. BC Hydro may require the Customer to provide it with control of these load shedding relays. During periods of potential system constraints, upon a Customer's request, BC Hydro will endeavour to provide Electricity normally provided by the Customer's electrical generation unit. The Customer is required to advise BC Hydro within 30 minutes of taking Electricity under this Rate Schedule for this purpose. If the Customer fails to advise BC Hydro within 30 minutes, measured Demand and Energy consumption will be billed under Rate Schedule 1823, 1825, 1827 or 1852, whichever is applicable. 4. Electricity taken under this Rate Schedule will not displace Electricity otherwise to be taken by the Customer under Rate Schedule 1823, 1825, 1827 or 1852. Electricity taken under this Rate Schedule will not displace electricity that would normally be generated by the Customer for the purpose of re-sale.

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	5. In addition to the charges specifically set out in this Rate Schedule, the Customer will pay for any additional facilities required to deliver Electricity under this Rate Schedule provided that BC Hydro obtains the prior consent of the Customer for construction of the additional facilities. 6. A Customer may be required to allow BC Hydro to install metering and communication equipment to measure the electricity output of the Customer's self-generation unit. 7. BC Hydro will bill for Electricity taken under Rate Schedule 1880 at the same time it bills for Electricity taken under Rate Schedule 1823, 1825, 1827 or 1852, whichever is applicable.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Note	The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement Nos. 5 and 6, or Electric Tariff Supplement Nos. 87 and 88, as applicable.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.
Rate Increase	Effective April 1, 2019~~2016 and April 1, 2017~~ the Energy Charge under this Rate Schedule include~~d~~s an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the Energy Charge under this Rate Schedule includes an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:____________________________

ORDER NO.____________________________ ____________________________
COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 1891 – TRANSMISSION SERVICE – SHORE POWER SERVICE

Availability	For the supply of Shore Power to Port Customers for use by Eligible Vessels while docked at the Port Customer's Port Facility, on an interruptible basis. Supply is at 60 kV or higher.
Applicable in	Rate Zone I.
Rate	**Administrative Charge:** $150.00 per month plus **Energy Charge:** 10.160~~9.509~~ ¢ per kWh for all kWh in a billing period
Definitions	For purposes of this Rate Schedule, capitalized terms have the meanings given to them in the Shore Power Service Agreement (Electric Tariff Supplement No. 86).
Special Conditions	1. BC Hydro agrees to provide Electricity under this Rate Schedule to the extent that it has energy and capacity to do so. BC Hydro may refuse Service under this Rate Schedule in circumstances where BC Hydro does not have sufficient energy or capacity. For greater certainty, BC Hydro will not be required to construct a System Reinforcement under Electric Tariff Supplement No. 6 to provide Shore Power Service under this Rate Schedule. 2. The terms and conditions under which Shore Power Service is supplied are contained in the Shore Power Service Agreement (Electric Tariff Supplement No. 86). The Port Customer will pay to BC Hydro the charges set out in this Rate Schedule in addition to any charges set out in the Shore Power Service Agreement.

ACCEPTED:____________________________

ORDER NO.____________________________ ______________________________
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	3. A Port Customer that provides Port Electricity at a Port Facility under Rate Schedules 1600, 1601, 1610, 1611 (Large General Service) or 1823 (Stepped Rate) is not eligible to take Shore Power Service under this Rate Schedule to provide Port Electricity to that Port Facility, or a Port Facility served by the same BC Hydro delivery facilities. 4. On each occasion, if any, that BC Hydro is required to dispatch power line technicians or other workers to operate the switchgear for each connect and disconnect of Eligible Vessels docked at the Port Customer's Port Facility, BC Hydro will charge, and the Port Customer will pay, the reasonable time and labour costs for this service. The charge will be based on prevailing BC Hydro contracted labour rates and will be separately itemized on the Port Customer's monthly bill.
Taxes	The rates set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

ACCEPTED:__________________________

ORDER NO.__________________________ ________________________________

COMMISSION SECRETARY

5. TRANSMISSION SERVICE

RATE SCHEDULE 3808 – TRANSMISSION SERVICE – FORTISBC INC.

Availability	This Rate Schedule is available to FortisBC Inc. (FortisBC) in accordance with the terms and conditions of the Agreement between BC Hydro and FortisBC entered into and deemed effective July 1, 2014 (Power Purchase Agreement). Contract Demand must not exceed 200 MW in any hour.
Applicable in	For Electricity delivered to FortisBC at each Point of Delivery as defined in the Power Purchase Agreement.
Rate	**Demand Charge:** $8.697~~8.139~~ per kW of Billing Demand per Billing Month plus **Energy Charge:** Tranche 1 Energy Price: 5.098~~4.771~~ ¢ per kWh Tranche 2 Energy Price: 9.509 ¢ per kWh

ACCEPTED:____________________

ORDER NO.____________________

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COMMISSION SECRETARY

Definitions	1. Billing Demand The Billing Demand in any Billing Month will be the greatest of: (a) The maximum amount of Electricity (in kW) scheduled under the Power Purchase Agreement, for any hour of the Billing Month; (b) 75% of the maximum amount of Electricity (in kW) scheduled under the Power Purchase Agreement in any hour in the 11 months of the Term immediately prior to the Billing Month (or less than 11 months, if the Effective Date is less than 11 months prior to the month); and (c) 50% of the Contract Demand (in kW) for the Billing Month. If FortisBC has reduced the Contract Demand in accordance with the Power Purchase Agreement, the amount of Electricity specified in item (b) above may not exceed an amount equal to 100% of the Contract Demand. 2. Maximum Tranche 1 Amount The Maximum Tranche 1 Amount for each Contract Year is 1,041 GWh. 3. Scheduled Energy Less Than or Equal to Annual Energy Nomination In any Contract Year, for the amount of the Scheduled Energy taken or deemed to be taken that is less than or equal to the Annual Energy Nomination, FortisBC will pay: (a) The Tranche 1 Energy Price for each kWh of such Scheduled Energy taken or deemed taken that is less than or equal to the Maximum Tranche 1 Amount; and (b) The Tranche 2 Energy Price for each kWh of such Scheduled Energy taken that exceeds the Maximum Tranche 1 Amount.

	4. Scheduled Energy Exceeding the Annual Energy Nomination In any Contract Year, for the amount of the Scheduled Energy taken or deemed to be taken that exceeds the Annual Energy Nomination, FortisBC will pay: (a) 150% of the Tranche 1 Energy Price, for each kWh of such Scheduled Energy taken or deemed taken that that exceeds the Annual Energy Nomination, but is less than or equal to the Maximum Tranche 1 Amount; and (b) 115% of the Tranche 2 Energy Price, for each kWh of such Scheduled Energy taken that exceeds the Annual Energy Nomination and also exceeds the Maximum Tranche 1 Amount. 5. Annual Minimum Take In any Contract Year, FortisBC will schedule and take an amount of Electricity equal to at least 75% of the Annual Energy Nomination, and will be responsible for any Annual Shortfall.
Note	The terms and conditions under which Service is supplied to FortisBC are contained in the Power Purchase Agreement.
Taxes	The rates and charges set out in this Rate Schedule are exclusive of goods and services and provincial sales taxes.
Rate Rider	The Deferral Account Rate Rider as set out in Rate Schedule 1901 applies to all charges payable under this Rate Schedule, before taxes and levies.

ACCEPTED:____________________

ORDER NO.____________________ ____________________

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Rate Increase	The Tranche 1 Energy Price and Demand Charge set out above are subject to the same rate adjustments as Rate Schedule 1827 (Rate for Exempt Customers). Tranche 2 Energy Price is subject to changes as provided for in the Power Purchase Agreement. Effective April 1, 2019~~2016 and April 1, 2017~~ the Tranche 1 Energy Price and the Demand Charge under this Rate Schedule include~~d~~ an interim rate increase~~s~~ of 6.85%~~4.0% and 3.5%, respectively,~~ before rounding, ~~both~~ approved by BCUC Order No. ~~G-47-18~~.
	~~Effective April 1, 2018 the Tranche 1 Energy Price and the Demand Charge under this Rate Schedule include an increase of 3.0% before rounding, approved by BCUC Order No. G-47-18.~~

ACCEPTED:______________________________

ORDER NO.______________________________

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6. OTHER

RATE SCHEDULE 1901 – DEFERRAL ACCOUNT RATE RIDER

Applicability	The Deferral Account Rate Rider as set out below applies to all charges payable under other Rate Schedules of the Electric Tariff except for Rate Schedule 1903 and Electric Tariff Supplement Nos. 7, 8, 39, 77 and 94.
Deferral Account Rate Rider	No~~A~~ applicable charge ~~equal to 5% of all amounts otherwise payable under the applicable Rate Schedule, before taxes and levies~~.

ACCEPTED:____________________

ORDER NO.____________________ ____________________

COMMISSION SECRETARY

ATTACHMENT H

Annual Transmission Revenue Requirement

for Network Integration Transmission Service

1. The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be $~~825,612,000~~928,236,000.

2. The amount in (1) shall be effective until amended by the Transmission Provider or modified by the Commission.

Effective April 1, ~~2018~~2019, this rate schedule is ~~final~~ approved on an interim basis as per BCUC Order No. ______~~G-47-18~~.

ACCEPTED:____________________________

ORDER NO.____________________________ ____________________________
COMMISSION SECRETARY

Schedule 00

Network Integration Transmission Service

Availability	For wholesale transmission of electricity.
Rate	Monthly Transmission Revenue Requirement: Customers will be charged their load ratio share of one twelfth (1/12th) of the Network Transmission Revenue Requirement per month. The Transmission Revenue Requirement is shown in Attachment H. One-twelfth of the Transmission Revenue Requirement is $~~68,801,000~~77,353,000.
Taxes	The Rate and Charges contained herein are exclusive of applicable taxes.
Note	The terms and conditions under which Network Integration Transmission Service is supplied are contained in BC Hydro's OATT. Capitalized terms appearing in this Schedule, unless otherwise noted, shall have the meaning ascribed to them therein.

Effective April 1, 2019~~2018~~, this rate schedule is approved on an interim~~final~~ basis as per ~~by~~ BCUC Order No. ~~G-47-18~~ .

ACCEPTED:______________________________

ORDER NO.______________________________

COMMISSION SECRETARY

Schedule 01

Point-To-Point Transmission Service

Availability	For transmission of electricity on a firm and non-firm basis from one or more Point(s) of Receipt (POR) to one or more Point(s) of Delivery (POD).
Rate for Long-Term Firm Service	The Reserved Capacity Charge for the Long-Term Firm Service Rate will be up to a maximum price as set out below except where the POD is a point of interconnection between the Transmission System and the transmission system of FortisBC Inc., in which case the rate shall be zero ($0.00). The Maximum Reserved Capacity Charge is $~~70,555~~78,433/MW of reserved capacity per year to be invoiced monthly. Reserved Capacity Billing Demand The Reserved Capacity Billing Demand is determined for each POR(s), POD(s) pair. The Reserved Capacity for each pair of POR(s) and POD(s) will be the maximum non-coincident sum of the designated POR(s) and POD(s) included in the pair.

ACCEPTED:____________________________

ORDER NO.____________________________ ________________________________

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Schedule 01 – Point-To-Point Transmission Service (continued)

Rate for Short-Term Firm and Non-Firm Service	The posted prices for Short-Term Firm and Non-Firm Service will be less than or equal to a maximum price ($/MWh) as set out below, except where the POD is a point of interconnection between the Transmission System and the transmission system of FortisBC Inc., in which case the rate shall be zero ($0.00). Maximum Price for: 1. Monthly delivery: $~~5,879.58~~6,536.12/MW of Reserved Capacity per month. 2. Weekly delivery: $~~1,356.83~~1,508.34/MW of Reserved Capacity per week. 3. Daily delivery: $~~193.30~~214.89/MW of Reserved Capacity per day. 4. Hourly delivery: $~~8.05~~8.95/MW of Reserved Capacity per hour. Discount Rate: For discounted paths posted on the Transmission Provider's OASIS, the Transmission Customer shall pay each month for Reserved Capacity Billing Demand the greater of the rates set forth below and the rate offered by the Transmission Customer and accepted by the Transmission Provider up to the maximum rate for Short-Term Firm and Non-Firm Service: 1. Hourly delivery: $3/MW of Reserved Capacity per hour in the Heavy Load Hour period (06:00-22:00, Monday - Saturday, excluding NERC holidays) and $1/MW of Reserved Capacity per hour for the Light Load Hour period (remaining hours and days). 2. Daily delivery: sum of the hourly delivery charge in the 24 hour period in the day.
Reserved Capacity for Short-Term Firm and Non-Firm Services	The Reserved Capacity shall be the maximum of the sum of non-coincident POD(s) Capacity Reservations or sum of non-coincident POR(s) Capacity Reservations.

ACCEPTED:____________________

ORDER NO.____________________ ____________________
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Schedule 01 – Point-To-Point Transmission Service (continued)

Penalty Charge	In addition to the applicable rate for service and associated charges for Ancillary Services, a penalty charge will be applied to all unauthorized usage at a rate of 125 percent of the maximum hourly delivery charge.
Special Conditions	Discounts: The following conditions apply to discounts for transmission service: 1. any offer of a discount made by BC Hydro must be announced to all Eligible Customers solely by posting on the OASIS, 2 any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, 3. once a discount is negotiated, details must be immediately posted on the OASIS, and 4. for any discount agreed upon for service on a path, from POR(s) POD(s), BC Hydro must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same POD(s) on the Transmission System.
Taxes	The Rate and Charges contained herein are exclusive of applicable taxes.
Resales	The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff
Note	The terms and conditions under which Transmission Service is supplied are contained in BC hydro's Open Access Transmission Tariff. Capitalized terms appearing in this Rate Schedule, unless otherwise noted, shall have the meaning ascribed to them therein.

Effective April 1, 2019~~2018~~, this rate schedule is approved on an interim~~final~~ basis as per BCUC Order No. ~~G-47-18~~.

ACCEPTED:____________________________

ORDER NO.____________________________

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COMMISSION SECRETARY

Schedule 03

Scheduling, System Control, and Dispatch Service

Preamble	This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by BC Hydro. The Transmission Customer must purchase this service from BC Hydro. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below.
Availability	In support of Network Integration Transmission Service, Long and Short-Term Firm Point-to-Point Transmission Service, and Non-Firm Point-to-Point Transmission Service.
Rate	$~~0.100~~0.133 per MW of Reserved Capacity per hour.
Taxes	The Rate and Charges contained herein are exclusive of applicable taxes.
Note	A description of the methodology for discounting Scheduling, System Control and Dispatch Services provided under this Schedule is contained in Section 3 of the BC Hydro OATT.

Effective April 1, 2019~~2018~~, this rate schedule is approved on an interim~~final~~ basis as per BCUC Order No. ~~G-47-18~~.

ACCEPTED:____________________________

ORDER NO.____________________________

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COMMISSION SECRETARY

BC Hydro
Power smart

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix FF

Report on the Theory and Practice of Performance-Based Regulation

A REPORT ON THE THEORY AND PRACTICE OF PERFORMANCE-BASED REGULATION

By

Dennis L. Weisman Ph.D.*

December 12, 2018

EXECUTIVE SUMMARY

This report is designed to be a self-contained introduction to performance-based regulation (PBR) with an emphasis on the energy sector in North America. The main topics include: key differences between PBR and traditional cost-of-service regulation (COSR), the various forms of PBR and their efficiency properties, common misconceptions about PBR, the economic and public policy principles that should inform the design and implementation of PBR, the mechanics of PBR, the advantages and disadvantages of earnings sharing mechanisms, the importance of regulatory commitment and the role of benchmarking in PBR regimes.

Whereas COSR is frequently treated in the literature as a discrete alternative to PBR, these two types of regulatory regimes are best understood in terms of lying along a continuum based on the strengths of the incentives for efficient performance. The textbook model of COSR with no regulatory lag contemplates instantaneous rate reductions that serve to normalize excess returns. This regulatory regime lies at the far left on this continuum indicating extremely weak (low-powered) incentives. In contrast, long-term PBR with no earnings sharing or rebasing lies at the far right on this continuum indicating extremely strong (high-powered) incentives. Notably, COSR with a long regulatory lag may reside on this continuum to the right of a short-term PBR regime that incorporates a narrow deadband, pronounced earnings sharing and a full rebasing of rates at the end of the PBR term. In this special case, COSR exhibits more high-powered incentives than PBR. The key point is that PBR is not necessarily superior to COSR in all cases.

An important consideration concerns the unique challenges that arise in applying PBR to crown corporations and how these challenges may be overcome. The expected gains from adopting PBR may be subject to greater uncertainty in the case of crown corporations because they are *de facto* subject to two different regulatory authorities—the regulatory commission and the government owner. Nonetheless, PBR plans have been successfully applied to public enterprises.

Finally, if the PBR regime is not developed in accordance with sound economic principles, or there is not a strong commitment to the fundamental tenets of PBR on the part of either the regulator or the government, the significant resources required to design and implement a PBR regime would be difficult to justify. The adoption of PBR may simply fail the cost-benefit test under these conditions.

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* Professor of Economics *Emeritus*, Kansas State University. The funding for this study was provided by BC Hydro but the views expressed herein are exclusively those of the author.

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LIST OF FIGURES AND TABLES

1. Introduction

This report examines the theory and practice of performance-based regulation (PBR) with an emphasis on the energy sector, including electricity and natural gas, in North America. In certain cases, references are made to the telecommunications industry to compare and contrast the experience with incentive regulation in that sector with that of the energy sector.

Whereas traditional cost-of-service regulation (COSR) is frequently treated in the literature as a discrete alternative to PBR, these two types of regulatory regimes are best understood in terms of lying along a continuum based on the strengths of the incentives for efficient performance as illustrated in Figure 1. The textbook model of COSR with no regulatory lag contemplates instantaneous rate reductions that serve to normalize excess returns. This regulatory regime lies at the far left on this continuum indicating extremely weak (low-powered) incentives. In contrast, long-term PBR (price/revenue caps) with no earnings sharing or rebasing lies at the far right on this continuum indicating extremely strong (high-powered) incentives. Notably, COSR with a long regulatory lag may reside on this continuum to the right of a short-term PBR regime that incorporates a narrow deadband, pronounced earnings sharing and a full rebasing of rates at the end of the PBR term. In this special case, COSR exhibits more high-powered incentives than PBR.

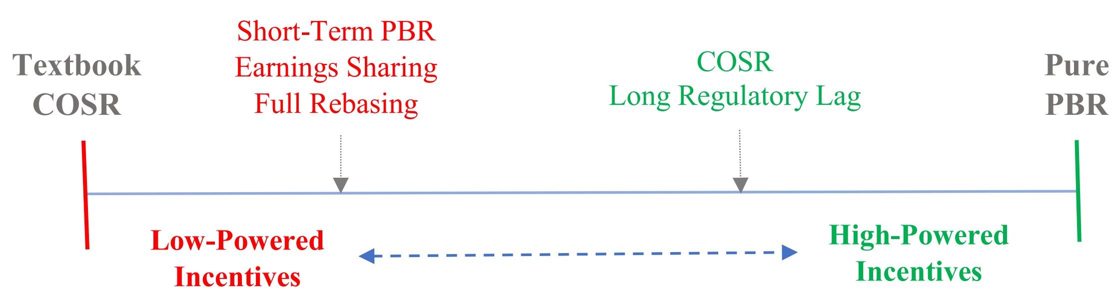

Figure 1. Continuum of Regulatory Regimes

In addition to reviewing the basic elements of PBR, this report addresses a number of important questions related to the design and implementation of PBR. These questions include but are not limited to the following.

- How is PBR defined and how does it differ from COSR?
- What are the most common forms of PBR?
- What are the efficiency properties of PBR and how do they differ from COSR?
- What are the most common misconceptions about PBR?
- What economic and public policy principles should guide the design of a PBR regime?
- How can PBR be designed to address conservation objectives?
- Is PBR superior to COSR in all settings?
- What are the advantages and disadvantages of earnings sharing mechanisms?
- What is the role of benchmarking in PBR regimes?
- What complexities arise in applying PBR to crown corporations?

While the economics literature typically compares the textbook models of COSR and PBR in extolling the superiority of the latter, the real world in which "the devil is in the details" is not nearly as straightforward. In addition, while numerous published econometric studies and literature surveys have concluded that incentive regulation in the North American telecommunications sector has conferred net gains on all key stakeholder groups (consumers, regulated firms, competitors and regulators), there is no comparable literature in the energy sector that permits such broad conclusions to be drawn at this point in time. In addition, while Canada appears to have firmly embraced PBR as a superior alternative to COSR, the experience with PBR in the United States is mixed and is perhaps best characterized as a series of fits and starts. What precisely explains this disparate experience with PBR in moving north and south of the border remains an outstanding question.

The outline for the remainder of this report is as follows. Section 2 provides a comprehensive overview of COSR and PBR and their respective incentive properties. This discussion includes common observations and misperceptions about PBR, a set of general PBR principles, the PBR alphabet as well as earnings sharing and efficiency carryover mechanisms. The implications of regulatory commitment for the performance of PBR is the subject of Section 3. Section 4 discusses the role of benchmarking in PBR regimes. The myriad issues that arise in applying PBR to crown corporations are examined in Section 5. Section 6 provides a summary and conclusion.

2. OVERVIEW OF COSR AND PBR

2.1 The Different Properties of Regulatory Regimes

There is a consensus in the literature that economic regulation should be limited to essential services that are not subject to the discipline of competitive market forces.[1, 2] Essential services are typically defined as services of such importance to the economic and social welfare of the citizenry that universal access to such services at affordable rates remains a key element of public policy. Traditional infrastructure industries in which economic regulation is applied include electric power, natural gas, telecommunications and water.[3]

1 See Alfred E. Kahn, THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS, New York. Volume I, John Wiley and Sons, 1970, pp. 11-12.

2 Professor David Sappington observes that "It is generally preferable to replace regulatory control with the discipline of competition when competition provides adequate protection for consumers." David E. M. Sappington, "Price Regulation," HANDBOOK OF TELECOMMUNICATIONS ECONOMICS, Martin Cave, Sumit Majumdar, and Ingo Vogelsang, eds., Amsterdam: North-Holland, 2002, Chapter 7, p. 265, note 58.

3 Economic regulation has also been applied to varying degrees in the transportation sector (commercial aviation, trucking and railroads).

Economic regulation can at best serve as an imperfect substitute for competition. This is the case because regulators do not have the requisite information to replicate a competitive market outcome.[4] Incentives play a critical role in a market economy *vis-à-vis* a centrally planned, command economy in allocating scarce resources to their highest-valued use and in encouraging the most efficient means of producing society's goods and services. In similar fashion, PBR seeks to put in place stronger incentives for efficiency relative to traditional COSR.[5]

It is instructive to commence by defining precisely what is meant by the term PBR (or what is commonly referred to as "$I - X$" regulation).[6] Incentive regulation or PBR "can be defined as the design and implementation of rules that encourage a regulated firm to achieve desired goals by

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4 Indeed, as Professor Alfred Kahn has observed:

> Manifestly, the operating expenses and capital outlays of public utility companies are by far the most important component of their rate levels, on the one hand, and the efficiency with which they make use of society's resources on the other. Therefore, in terms of their quantitative importance, it would be reasonable to expect regulatory commissions to give these costs the major part of their attention. But in fact they have not done so; they have given their principal attention instead to the limitation of profits.
>
> The reasons for this perverse distribution of effort illustrate once again the inherent limitations of regulation as an institution of effective social control of industry. Effective regulation of operating expenses and capital outlays would require a detailed, day-by-day, transaction-by-transaction, and decision-by-decision review of every aspect of the company's operation. Commissions could do so only if they were prepared completely to duplicate the role of management itself. This society has never been willing to have commissions fill the role of management and doubtless with good reason: it is difficult to see how any company could function under two separate, coequal managements, each with an equally pervasive role in its operations.

Alfred E. Kahn, THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS, Volume I, New York: John Wiley and Sons, 1970, pp. 29-30.

5 The terms PBR and incentive regulation are used interchangeably. In common parlance, PBR typically refers to incentive regulation in the electric power and natural gas industries. The term incentive regulation is more commonly used in the telecommunications industry.

6 I represents a measure of inflation and X is a productivity factor. The X factor determines the trajectory of prices/revenues over the course of the PBR term after controlling for inflation (i.e., real prices/revenues). Hence, a positive (negative) X factor allows prices/revenues to increase slower (faster) than the rate of inflation, abstracting from the other components of the PBR plan discussed below.

granting some, but not complete, discretion to the firm."[7] In the preponderance of cases, PBR has been applied to private enterprises rather than public enterprises. The firm is granted some discretion under a PBR plan to induce it to employ its superior information (e.g., detailed knowledge of its cost structure and consumer demand) to further social goals. The firm's discretion is limited, however, because its goals are generally not congruent with social goals. The regulated (private) firm is obliged to act in the best interests of its shareholders (e.g., maximizing financial returns), while social goals generally involve more broadly defined interests (e.g., efficiency).

Regulators recognized the potential economic benefits that could be realized from (partially) decentralizing control to the regulated firm. The early economics literature on price cap regulation emphasizes two distinct yet related themes. First, the regulator is not omniscient and hence the regulated firm may have superior information with respect to its own costs and demands. Second, efficiency is the result of a discovery process and the regulated firm must be provided with the requisite incentives to invest in the (unobservable) effort required for such discovery.

> The interest in price caps also reflects a growing understanding that governmental regulation is limited in what it can accomplish. The firms that are the object of regulation are almost always better informed than regulators about their costs and the consequences of adopting particular, detailed regulatory schemes for prices or conditions of service. Thus, rather than creating regulation based on the premise of an omniscient regulator being able to set optimal prices based on full knowledge of costs and demand, a more realistic regulatory goal is to design incentive mechanisms for the regulated firm that will lead it to maximize society's objectives (whether these are efficiency, distributive, or other objectives) while pursuing its self interest.[8]
>
> It [RPI – X] does not assume costs and demands are given or known; indeed, the problem is to provide adequate incentives for the company to discover them. The aim is to stimulate alertness to lower cost techniques and hitherto unmet demands. The

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7 David E. M. Sappington, "Designing Incentive Regulation," *Review of Industrial Organization*, Volume 9, 1994, p. 246.

8 Jan Paul Acton and Ingo Vogelsang, "Introduction to the Symposium on Price Cap Regulation," *Rand Journal of Economics*, Volume 20(3), Autumn 1989, p. 369.

> emphasis is on productive rather than allocative efficiency (and even the $RPI - X$ price caps reflects distributional rather than allocative considerations).[9, 10]

It is useful to define a regulatory regime in terms of its underlying incentive properties, whether it provides the regulated firm with "high-powered" or "low-powered" incentives for performance. A high-powered regulatory regime is one in which the regulated firm is responsible for a large share of its actual costs. In contrast, a low-powered regulatory regime is one in which the regulated firm is typically able to affect a high degree of pass through of cost changes in the form of rate changes.[11] Hence, in a high (low)-powered regulatory regime the regulated firm retains a large (small) share of each additional dollar in earnings. Traditional, COSR is typically considered a relatively low-powered regulatory regime.[12] In contrast, pure price (revenue) cap regulation is typically considered a relatively-high powered regulatory regime.[13]

Regulatory regimes may be partitioned into two basic types: (1) earnings-based regulatory regimes and (2) price or revenue-based regulatory regimes.[14] In addition, regulators may opt for a

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9 Michael E. Beesley and Stephen C. Littlechild, "The Regulation of Privatized Monopolies in the United Kingdom," *Rand Journal of Economics*, Volume 20(3), Autumn 1989, p. 467.

10 In addition, Professor Littlechild's latest reflections upon the intellectual foundations for price caps in the UK reveal that the focus of price cap regulation was not cast in traditional negative terms, the "prevention of excess profits" but rather on improving efficiency and expanding the range of profitable opportunities through innovation and discovery. Stephen Littlechild, "The Birth of RPI-X and Other Observations," in THE UK MODEL OF UTILITY REGULATION, Ian Bartle, ed., London: CRI, September 2003, pp. 31-49.

11 See, for example, Jean-Jacques Laffont and Jean Tirole, A THEORY OF INCENTIVES IN PROCUREMENT AND REGULATION, Cambridge MA: The MIT Press, 1993, p. 11.

12 It should be noted, however, that even under COSR the power of the regime can be ratcheted up considerably if there is a relatively long regulatory lag (i.e., the period over which the regulated firm is not subject to an earnings review and a recalibration of rates to achieve a target rate of return). For a discussion of the benefits of regulatory lag in strengthening incentives, see Alfred E. Kahn, THE ECONOMICS OF REGULATION, Volume II, New York: John Wiley and Sons, 1971, pp. 48-9.

13 The adjective "pure" in this context refers to PBR regimes (price/revenue caps) in which there is no *ex post* sharing of earnings.

14 The earnings-based regulatory regime can be expressed in terms of the constraint $\Pi \leq \overline{\Pi}$, where Π is the actual earnings of the regulated firm and $\overline{\Pi}$ is the earnings cap or maximum earnings allowed. Similarly, the price-based (revenue-based) regulatory regime can be expressed in terms of the constraint

mixed PBR regime in which price (revenue) cap regulation incorporates a safeguard in the form of earnings sharing to ensure that financial returns do not diverge too far from acceptable levels.[15] Earnings that are too high may prompt ratepayers to question whether regulation has been effective in protecting them against excessive rates. Conversely, earnings that are too low may impede the regulated firm's ability to raise capital and thereby threaten its financial viability. In general, as discussed in greater detail below, incorporating earnings sharing into the PBR regime tends to weaken the power of the regime.

Traditional COSR is an example of an earnings-based regulatory regime that seeks to instill competitive discipline by limiting the regulated firm's financial returns. Pure price (revenue) cap regulation is an example of a price-based regulatory regime that seeks to instill competitive discipline by capping the prices (revenues) of the regulated firm. A central question in the literature on the economics of regulation concerns whether earnings-based regimes, price-based regimes, or some combination of the two types of regulation are the best means to replicate the discipline of competitive markets.[16]

$P \leq \bar{P}$ or $R \leq \bar{R}$, where P is an index of average prices, R is revenues, $\bar{P}$ is the regulator-determined price cap and $\bar{R}$ is the regulator-determined revenue cap. Notably, price (revenue) caps have similar efficiency properties, but dissimilar pricing properties. See Michael Crew and Paul Kleindorfer, "Price Caps and Revenue Caps: Incentives and Disincentives for Efficiency," in PRICING AND REGULATORY INNOVATIONS UNDER INCREASING COMPETITION, Michael A Crew, ed., Boston: Kluwer Academic Press, 1996, pp. 21-38.

15 The various arguments both for and against earnings sharing in PBR regimes are reviewed in Section 2.6 *infra*.

16 Paul L. Joskow, "Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks," in ECONOMIC REGULATION AND ITS REFORM: WHAT HAVE WE LEARNED?, Nancy L. Rose, ed., Chicago: The University of Chicago Press, 2014, pp. 291-344.

Broad-based, indexed PBR plans take a number of different forms,[17] including price caps, revenue caps, and revenue-per-customer caps.[18] The superior incentive properties of price cap regulation derive from breaking the link between allowed revenues and costs. This feature of price cap regulation renders the regulated firm the residual claimant for its efficiency gains. This means that the regulated firm retains a full dollar for each additional dollar of cost savings until rebasing occurs at the end price cap regime.[19] This contrasts with COSR in which efficiency gains are typically not retained by the firm for a prolonged period of time but rather passed along to consumers in the form of price reductions, or a slower rate of price growth.

> As a rough characterization, under rate-of-return regulation reviews are infrequent, and the regulatory lag is endogenous because either side can request a review, whereas under price caps the lag is relatively long, and the date of the next review is fixed in advance. The difference is one of degree rather than kind.[20]

The Ontario Energy Board (OEB) offers the following perspective on the differences between a long-term PBR regime and COSR.

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17 A broad-based PBR plan is one that permits substantial variation in the earnings of the regulated firm and does not link the variation explicitly to specific performance dimensions (e.g., service quality, reliability or cost-containment for specific capital projects). Indexed PBR plans directly link the maximum-permissible prices or revenues (i.e., the price cap or revenue cap) to an external price index. Hence, in the transition from COSR to PBR, the standard for consumer protection changes from prevention against excessive profits to prevention against excessive prices. See Jordan Jay Hillman and Ronald Braeutigam, PRICE LEVEL REGULATION FOR DIVERSIFIED PUBLIC UTILITIES, Boston: Kluwer Academic Publishers, 1989, pp. 80-81.

18 The latter two are more common in the electric power industry because they do not encourage demand growth and therefore are viewed as more compatible with conservation measures. In contrast, price cap regulation is the standard approach in the telecommunications industry in both Canada and the United States. Price cap regulation is also used in the current PBR plan in Alberta for electric distribution companies (as they have yet to experience negative demand growth).

19 Regulatory commitment is key to the superior performance of price cap regulation. The regulated firm must credibly believe that the regulator will not simply appropriate the cost savings it was encouraged to discover. See Dennis L. Weisman, "Is There 'Hope' for Price Cap Regulation?" *Information Economics and Policy*, Volume 14(3), 2002, pp. 349–370. Please refer to Section 3 for additional discussion of this important issue.

20 Mark Armstrong, Simon Cowan, and John Vickers, REGULATORY REFORM, Cambridge MA: The MIT Press, 1994, p. 172.

> By way of commentary, the Board observes that PBR is not just light-handed cost of service regulation. For the electricity distribution utilities in Ontario, PBR represents a fundamental shift from the historical cost of service regulation. It provides the utilities with incentive for behaviour which more closely resembles that of competitive, cost-minimizing, profit-maximizing companies. Customers and shareholders alike can gain from efficiency enhancing and cost-minimizing strategies that will ultimately yield lower rates with appropriate safeguards for service quality. Under PBR the regulated utility will be responsible for making its investments based on business conditions and the objectives of its shareholder within the constraints of the price cap, and subject to service quality standards set by the Board.[21]

Under COSR, successful efforts at discovery and innovation are typically "rewarded" with mandated reductions in service rates should earnings be deemed excessive. Unsuccessful efforts at innovation and discovery run the risk of cost disallowances. Hence, from the perspective of the regulated firm, COSR can devolve into a "game" of *heads you win and tails I lose*. Consequently, the expected returns to a utility from innovation under COSR may be extremely limited if they exist at all.[22] Conversely, under PBR the utilities are permitted to retain the fruits of their successful efforts (and also bear the costs of their unsuccessful efforts) *pro tempore* which underscores their willingness to bear the risks associated with investment in innovation.[23]

Relative to traditional COSR, the theoretical literature finds that delinking revenues and costs under pure price (revenue) cap regulation, which renders the firm the residual claimant for its efficiency gains,[24] provides the regulated firm with incentives to (1) operate with the least-cost

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21 Ontario Energy Board, RP-1999-0034 Decision with Reasons, January 18, 2000, Paragraph 2.0.14.

22 This discussion refers to the stylized, textbook model of COSR. In practice, regulatory lag can strengthen the incentives of a regulated firm under COSR because it does not instantaneously appropriate efficiency gains and pass them on to consumers in the form of lower rates.

23 It should be noted that intellectual property laws, including copyrights, patents and trademarks are designed to operate in a similar fashion. These laws are structured to reward the successful innovator with temporary monopolies to provide the requisite incentive for innovation. Specifically, they permit the successful innovator to enjoy the fruits of the innovation for a specific period of time before allowing other firms to use the innovation which concomitantly reduces market prices. See Susan Scotchmer, INNOVATION AND INCENTIVES, Cambridge MA: The MIT Press, 2004, chapter 3.

24 In this context, the term *residual claimant* means that the regulated firm has claim to the entirety of the difference (residual) between its revenues and costs just like any other firm operating in a competitive

technology; (2) operate with no waste; (3) diversify efficiently into new markets; (4) undertake efficient levels of cost-reducing innovation; (5) accurately report its costs;[25] and (6) eliminate regulatory abuse.[26]

These superior incentives for efficiency derive from the fact that pure price cap regulation operates much like a *fixed-price contract*. This property benefits consumers because the prices they pay do not vary directly with the reported costs of the firm. As a result, consumers bear little or no risk for the duration of the price cap regime. Conversely, traditional COSR (and some forms of price cap regulation with earnings sharing) operate much like a *cost-plus contract*. This means that the prices that consumers pay under COSR tend to vary directly with the reported costs of the firm and therefore may exhibit greater volatility. In other words, consumers bear more risk.

2.2 Preliminary Observations about PBR

This subsection discusses some preliminary observations and misconceptions about PBR as a precursor to the development of a set of general PBR principles in the following subsection.

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market. One key difference is that the regulated firm's prices are "capped" by regulation, whereas the forces of supply and demand interact to determine the market price that competitive firms treat as exogenous (i.e., beyond their control). In other words, just as the market price is exogenous to the behavior of any one firm in the market, changes in the price cap should be exogenous to the behavior of the regulated firm.

25 Ronald Braeutigam and John C. Panzar, "Diversification Incentives Under 'Price-Based' and 'Cost-Based' Regulation," *Rand Journal of Economics*, Volume 20(3), 1989, pp. 373-391.

26 In this context, abuse refers to resources consumed by the regulated firm for which the realized costs exceed the benefits. In other words, abuse represents expenditures on resources that the regulated firm would not undertake if it had to bear their full cost. See Glenn Blackmon, INCENTIVE REGULATION AND THE REGULATION OF INCENTIVES, Boston: Kluwer Academic Publishers, 1994. It is instructive to elaborate further upon the problem of abuse that can arise under earnings sharing. Suppose the regulated firm is operating in a region of financial returns where the "earnings tax" is 50 percent. This means that each additional dollar of expenditures only costs the regulated firm 50 cents. This asymmetry provides the regulated firm with incentives to incur a dollar's worth of costs when the benefits it derives are less than one dollar (but no lower than 50 cents). In contrast, under pure price cap regulation, an extra dollar of expenditures costs the firm precisely one dollar. Hence, the regulated firm, similar to a competitive firm, would incur expenditures only when the benefits are at least as great as the costs.

Preliminary PBR Observations	
Observation 1.	The Regulated Firm Under PBR Bears Greater Risk in Exchange for the Prospect of Greater Reward.
Observation 2.	PBR is Not a One-Size-Fits All Proposition.
Observation 3.	The Adoption of PBR is Not a Zero-Sum Game.
Observation 4.	Broad-based PBR is Generally Superior to Targeted PBR.
Observation 5.	PBR in North America Has Not Realized the Same Traction in Electricity as Incentive Regulation in Telecommunications.
Observation 6.	PBR May Not Be Preferable to COSR in All Settings.

2.2.1 Observation 1 Explained (Risk-Return Tradeoffs)

The greater risk that the firm bears under PBR must be coupled with the distinct possibility, though not a guarantee of greater reward. The prospect of greater reward is the impetus for the regulated firm's investment in cost-reducing effort.

> Absent credible rewards for superior performance and/or credible penalties for poor performance, the regulated firm will have little incentive to incur the effort costs that increase the likelihood of good performance.[27]

As discussed in greater detail in Section 3 below, the risk-return tradeoff under PBR is critical to a strong regulatory commitment and, in turn, the performance of PBR. A PBR regime that appropriates "excess earnings" during prosperous times and questions the regulated firm's diligence in cost control during less prosperous times cannot be expected to improve upon traditional COSR.

2.2.2 Observation 2 Explained (PBR Plans are Heterogeneous)

[27] David E. M. Sappington, "Designing Incentive Regulation," *Review of Industrial Organization*, Volume 9, 1994, pp. 262-263.

A PBR plan that is implemented for a particular company should reflect both the type of behavior the regulator wishes to encourage (which can vary across companies) and the unique characteristics of the regulated industry and the regulated company. As Professor Guthrie concludes from his survey of the economic literature on the relationship between regulation and infrastructure investment:

> The two most important lessons to be drawn from the literature surveyed here are that there is no single combination of regulatory settings that is best in all situations and that the various components of a regulatory scheme are interrelated. The most appropriate regulatory scheme for a given situation will depend on the characteristics of the firm and industry being regulated, as well as the institutional environment.[28]

2.2.3 Observation 3 Explained (PBR is Not Zero-Sum)

If PBR were to be a zero-sum game, the gains to regulated firms would be perfectly offset by the losses to consumers. A carefully designed PBR plan need not result in this outcome. In fact, the empirical evidence from the U.S. telecommunications industry suggests that incentive regulation was a *win-win proposition* for all key stakeholders (consumers, firms, regulators and competitors).[29, 30] What is more, as a general proposition the efficiency gains that arise under PBR should not be construed to suggest that the regulated firm was deliberately inefficient under COSR.

> In spite of the fact that incentive regulation can be a “win-win” proposition, some parties view incentive regulation as a little more than a “scheme” used by utilities to increase their profits and earn windfall gains. These added profits may even be viewed as “bribes” to get utilities to do what they should be doing already. A common refrain is that because utilities have a “statutory obligation” to be efficient, any additional rewards for achieving efficient behavior through incentive regulation are

28 Graeme Guthrie, “Regulating Infrastructure: The Impact on Risk and Investment,” *Journal of Economic Literature*, Volume 44(4), December 2006, p. 966.

29 See, for example, Jaison R. Abel, “The Performance of The State Telecommunications Industry Under Price-Cap Regulation: An Assessment of The Empirical Evidence,” NRRI 00-14, The National Regulatory Research Institute, September 2000.

30 A common litmus test for PBR performance concerns whether consumers realized lower rates or a slower rate of price escalation under PBR than they would have experienced under traditional COSR.

> unnecessary—and serve only to foster an inequitable distribution of efficiency gains between regulated firms and consumers. This line of argument would seem to suggest that any efficiencies realized by the regulated firm following the adoption of incentive regulation must imply that, under cost-of-service regulation, regulated entities either deliberately engaged in inefficient behavior or were able to "conceal" more efficient operating practices from regulators through their superior knowledge of operating conditions.[31]
>
> While the possibility of such behavior cannot be ruled out *a priori*, this claim is incorrect as a general proposition. This is because the achievement of performance gains is first and foremost a "discovery process" in which more efficient operating practices and superior use of technology are learned over time. It is the recognition of this discovery process that leads to the conclusion that the efficiency gains realized under incentive regulation need not imply that the firm was knowingly inefficient under cost-of-service regulation. To the contrary, it is quite plausible that the firm under COSR was as efficient as it knew how to be.[32]

2.2.4 Observation 4 Explained (Merits of Broad-Based PBR)

If a PBR plan targets financial incentives too specifically on a single dimension of the firm's performance, the firm will be inclined to devote excessive attention to this one dimension and neglect other important dimensions.[33] Suppose, for example, that a regulator's primary goal is to implement the lowest possible prices for electric power. In addition, however, the regulator is concerned about the level of service quality. If the regulator rewards the firm solely on the basis of average prices, the firm may have incentives to allow service quality to deteriorate. Therefore, even though the regulator's primary goal is to elicit low prices for electricity, it would be ill-advised to ignore critical dimensions of service quality in designing a PBR plan. Instead, the

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[31] Dennis L. Weisman and Johannes P. Pfeifenberger, "Efficiency as a Discovery Process: Why Enhanced Incentives Outperform Regulatory Mandates," *The Electricity Journal*, Volume 16(1), January/February 2003, p. 59 (footnote omitted).

[32] *Id*., footnote omitted.

[33] This discussion is based, in part, on David E. M. Sappington and Dennis L. Weisman, "Seven Myths About Incentive Regulation," in PRICING AND REGULATORY INNOVATIONS UNDER INCREASING COMPETITION AND OTHER ESSAYS, Michael A. Crew, ed., Boston: Kluwer Academic Publishers, 1996, pp. 5-8.

regulator should couple financial incentives to lower electricity prices with supplementary financial incentives to maintain or improve service quality.[34]

More generally, while PBR plans should be more broad-based rather than overly targeted, this does not mean that such incentive plans should force the firm to bear financial responsibility for all possible dimensions of its performance. To the contrary, a well-designed PBR plan should hold the firm financially responsible for dimensions of its performance over which it exercises significant control, and relieve the firm of financial responsibility for performance dimensions over which it has little or no control.

2.2.5 Observation 5 Explained (Disparate Adoption of PBR)

The pervasive adoption of incentive regulation in the telecommunications industry has not been replicated in the electric power industry. PBR in the electric power industry has generally failed to gain traction, though this trend is more evident in the U.S. than in Canada.[35] Plans were often terminated prematurely or were not renewed once they expired. While there is no consensus view explaining this disparate adoption of PBR across the two industries, the literature has identified several factors that may help to explain this phenomenon.[36]

[34] For example, the regulator may condition the degree of earnings sharing on the level of service quality provided by the regulated firm. When the regulated firm maintains or improves service quality, it may be permitted to retain a larger share of realized earnings and conversely.

[35] Even in Canada, however, the proper treatment of capital in the PBR regime has confounded regulators. The process of developing the appropriate treatment of capital within a PBR regime has proven to be an iterative one. This contrasts with the experience in the telecommunications industry in which an "equilibrium" model of incentive regulation that was remarkably uniform across companies and jurisdictions emerged relatively quickly. The electricity sector is seemingly still in search of an equilibrium model of PBR.

[36] David E. M. Sappington and Dennis L. Weisman, "The Price Cap Regulation Paradox in the Electricity Sector," *The Electricity Journal*, Volume 29, April 2016, pp. 1–5; and David E. M. Sappington and Dennis L. Weisman "The Disparate Adoption of Price Cap Regulation in the U.S. Telecommunications and Electricity Sectors," *Journal of Regulatory Economics*, Volume 49(2), April 2016, pp. 250–264.

Industry Competition

One of the desirable properties of price (revenue) cap regulation is that it (i) provides the regulated firm with greater pricing flexibility necessary to respond to increasing competition; and (ii) protects competitors by precluding the regulated firm from offsetting competitive losses by increasing rates for monopoly services. Competition has been less pronounced in the electric power industry than in the telecommunication industry. As a result, the impetus for adopting PBR in the electric power sector may be somewhat less. This may change, however, with public policies designed to increase competition and distributed generation. Vertically-integrated utilities are particularly likely to require pricing flexibility to retain large users on their systems. This closely parallels the experience of telecommunications providers that were especially vulnerable to large users bypassing their networks.

Differential Productivity Growth Rates

The telecommunications industry, driven in part by Moore's law,[37] has experienced rapid productivity growth. Conversely, productivity growth has slowed in the electric power industry.[38,]

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[37] Moore's Law describes the rapid decline in the cost of computing power, which translates directly into reduced costs of supplying switched telecommunications services. Moore's Law roughly states that "the cost of a given amount of computing power halves every 18 months." Jonathan Nuechterlein and Philip Weiser, DIGITAL CROSSROADS, Cambridge MA: MIT Press, Second Edition, 2013, p. 149.

[38] Productivity is defined as the ratio of outputs to inputs, whereas productivity growth is defined as the percentage change in outputs less the percentage change in inputs. The average annual total factor productivity growth rate for the 72 U.S. electricity and gas distribution firms examined in a recent study was 0.85 between 1973 and 2009. The corresponding average annual growth rate between 2000 and 2009 was -1.08. Jeff Makholm, Agustin Ros, and Meredith Case, "Total Factor Productivity and Performance-Based Ratemaking for Electricity and Gas Distribution," Presented at the 31st Annual Eastern Conference of the Center for Research in Regulated Industries, May 2012. Regulators have also recognized this trend. For example, the Alberta Utilities Commission adopted a combined *X* and stretch factor of 1.16 in 2012, but recently reduced that value to 0.3 in its latest order. This reflects a 74 percent reduction in just 4 years. Alberta Utilities Commission, Decision 2012-237, Rate Regulation Initiative Distribution Performance-Based Regulation September 12, 2012. Alberta Utilities Commission, Decision 20414-D01-2016 (errata), 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, February 6, 2017. The Massachusetts Commission recently adopted a negative *X* factor in its PBR plan for Eversource. This marks the first time that a

[39] This suggests that PBR may be a harder sell in electric power than it is in telecommunications. For example, regulators in the telecommunications industry could promise consumers real price reductions over time. In contrast, in the electric power industry regulators may only be able to promise consumers a slower rate of price growth. Furthermore, when productivity growth is declining over time, a backward-looking *X* factor (one based on historical data) is likely to overestimate the industry's capabilities going forward. This may well explain why PBR plans were not renewed or prematurely terminated in the electric power industry. In contrast, incentive regulation plans in the telecommunications industry have demonstrated remarkable staying power.

Moreover, the issue of supplemental capital provisions in the PBR plans in the electricity sector has no direct counterpart in incentive regulation plans in the telecommunications sector.[40,]

regulatory commission in North America has adopted a negative *X* factor in a PBR plan for distribution. See Department of Public Utilities, D.P.U. 17-05, Order Establishing Eversource's Revenue Requirement, November 30, 2017. For a discussion of the implications of a negative *X* factor in PBR plans, see Mark E. Meitzen, Phillip E. Schoech and Dennis L. Weisman, "Debunking the Mythology of PBR in Electric Power," *The Electricity Journal*, Volume 31(3), April 2018, pp. 39-46.

39 The fact that industry TFP growth has turned negative more recently is not dispositive of the industry becoming less efficient because the conditions under which service is provided have become more challenging. For example, providing security in today's environment means protecting against cyber threats and drone attacks. This contrasts sharply with yesteryear's security that may have required only a night watchman and a chain-link fence. Distributed generation requires costly infrastructure investments to allow wind/solar generators to interconnect with the distribution system. All these activities require more intensive use of inputs without necessarily generating any corresponding increase in billable outputs for the electric utilities. Finally, increased competition is likely to result in reduced output growth without a proportional reduction in input growth, especially if the utilities bear the obligation to serve as carriers of last resort. See Dennis L. Weisman, "Are the Electric Utilities Aboard the 'Train to Ithaca'?" *The Electricity Journal*, Volume 30(5), June 2017, pp. 6–9.

40 Supplemental capital refers specifically to the deficiency between capital requirements and the level of capital that is funded under the "$I - X$" PBR plan. The differences in the treatment of capital in PBR plans across the two industries can largely be explained by some of the institutional differences between the industries. Specifically, strong demand growth and falling costs that resulted in higher productivity growth allowed the telecommunications industry to fund its capital requirements under the $I - X$ cap. In addition, telecommunications firms may have been concerned that requesting supplemental capital funding would increase the likelihood that regulatory oversight would attach to services that are not presently regulated, including broadband, long-distance and video entertainment.

[41] One possible explanation for this phenomenon is that price caps based on backward-looking *X* factors allowed for increasing price-cost margins over time in telecommunications that were sufficient to fund capital requirements. In contrast, backward-looking *X* factors in the electricity sector may well result in decreasing price-cost margins over time that would render it more difficult to fund capital requirements absent special provisions in the PBR plan. This may occur because unit costs are growing at a faster rate than prices. These observations may explain why in telecommunications incentive regulation was largely driven by the regulated firms, whereas PBR in electricity and natural gas is more often spearheaded by regulators.

Conservation Concerns

Price cap regulation encourages the regulated firm to increase demand when price-cost margins are positive. While this increased demand is viewed favorably in the telecommunications industry, it is viewed less favorably in the electric power sector wherein there are conscious efforts to curtail consumption due to environmental concerns. This is one of the reasons why revenue caps and revenue-per-customer caps (along with revenue decoupling) are common forms of PBR in the electric distribution industry.[42] The latter two PBR regimes are more common in the electric power

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41 Notably, it was common in the telecommunications industry for regulators to extract upfront "entry fees" from the regulated firms under their purview for the right to operate under price cap regulation rather than traditional rate-of-return regulation. These entry fees took many different forms, including network infrastructure/modernization commitments, rate freezes, bill credits and refunds. See David E. M. Sappington and Dennis L. Weisman, DESIGNING INCENTIVE REGULATION FOR THE TELECOMMUNICATIONS INDUSTRY, Cambridge MA: The MIT Press, 1996, chapter 3. The rationality axiom suggests that these firms would not have "purchased" the property right for price cap regulation unless they had a reasonable expectation of increased profitability.

42 Nonetheless, conservation objectives can be addressed under price cap regulation. The regulator could implement PBR in combination with rate design changes that increase the fixed component of the customer's monthly charge while simultaneously reducing the volumetric charge toward incremental cost. By reducing or eliminating the price-cost margin on usage, the regulator can discourage the utility from expanding output. A potential drawback to this approach is that a lower usage change may (depending on the price elasticity of demand) encourage greater consumption which may conflict with conservation goals. This drawback can be addressed by allowing for a positive price-cost margin but using the margin to fund conservation/educations programs rather than allowing it to flow through to

industry because they do not encourage demand growth and therefore are viewed as more compatible with conservation measures.

Reliability Concerns

The stronger incentives for cost control that accompany PBR can cause utilities to cut back on service quality and reliability.[43] This may be somewhat less of a concern in the telecommunications sector given the multitude of network platforms and service providers, including wireless and cable television.

Regulatory Bargains

In the telecommunications industry, regulated firms are multi-product providers, including basic telephone service, long-distance, vertical services (caller-ID, call-waiting etc.), broadband, and video entertainment. This allows the regulator to strike bargains with telecommunications firms in which the prices of politically-sensitive basic service rates are capped as the *quid pro quo* for limited regulation or no regulation for high-margin, discretionary services. In contrast, electric

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the utility in the form of higher returns. Alternatively, as a side condition to the PBR plan the utility may face a constraint that limits the growth in average usage per customer. The utility can then be rewarded or penalized based on its performance in complying with this constraint. A utility that satisfies the conservation performance metric can be rewarded by being permitted to retain a larger share of its realized returns or a faster rate of growth in its prices/revenues. Conversely, a utility that fails to meet this conservation performance metric may be penalized by being permitted to retain a smaller share of its realized returns or a slower rate of growth in its prices/revenues. It is noteworthy that similar approaches have long been employed to ensure that utilities comply with reliability and quality-of-service metrics.

[43] One study finds that although service outages do not occur more frequently under PBR, the outages that do arise tend to persist for longer durations. This study also finds that reductions in service quality can be avoided with explicit financial penalties for sub-standard levels of service quality. Anna Ter-Martiroysyan and John Kwoka, "Incentive Regulation, Service Quality, and Standards in U.S. Electricity Distribution," *Journal of Regulatory Economics*, Volume 38(3), December 2010, pp. 258–273. For further discussion of the complexities inherent in designing reward/penalty schemes for efficient provisioning of service quality, see David E. M. Sappington, "Regulating Service Quality: A Survey," *Journal of Regulatory Economics*, Volume 27(2), 2005, pp. 123-154.

utilities tend not to be multi-product providers and hence the opportunity to strike such regulatory bargains is significantly reduced.

The California Meltdown

California experienced a meltdown of unprecedented proportion in its electricity sector in 2000.[44] A number of utilities in California were operating under a form of PBR when a combination of spiking wholesale electricity prices and frozen retail prices caused the firms to experience severe financial hardship. These events may have led some to attribute the firms' financial troubles to PBR, even though these difficulties were not limited to utilities that operated under PBR, and a host of factors other than PBR contributed to the meltdown (e.g., drought, siting issues, forced spot-market purchases, etc.). This misconception may have slowed the adoption of PBR nationwide.

2.2.6 Observation 6 Explained (PBR Not Always Superior to COSR)

Whereas high-powered regulatory regimes are generally superior to low-powered regulatory regimes, the expected gains from PBR over COSR may be small in certain settings. For example, when there are no informational asymmetries between the regulator and the regulated firm, there may be no efficiency gains from PBR. In this highly stylized setting, there is no reason to permit the firm to realize high earnings in order to elicit efficient behavior. The "command and control" regulator could simply direct the firm to operate efficiently in accordance with the competitive market standard. Second, the uncertainty over capital outlays may be so pronounced that efficient risk-bearing favors COSR over PBR. Third, earnings sharing can significantly reduce the power

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44 Severin Borenstein, "The Trouble with Electricity Markets: Understanding California's Restructuring Disaster," *Journal of Economic Perspectives*, Volume 16(1), Winter 2002, pp. 191–211; and John Jurewitz, "California's Electricity Debacle: A Guided Tour," *The Electricity Journal*, Volume 15(4), May 2002, pp. 10–29.

of the regulatory regime. Hence, if the effective "earnings tax" (the share of each additional dollar in cost savings that is forfeited) imposed on the regulated firm is high the expected incremental gains from adopting PBR may be small because PBR lies closer to COSR on the continuum of regulatory regimes.[45] Finally, when the regulator's commitment to the basic tenets of the PBR regime is sufficiently weak (i.e., it cannot be expected to deliver what it promises), there may be no credible claim that PBR will perform better than COSR.[46] These concerns may be compounded in the case of crown corporations that do not operate exclusively with a profit motive.

2.3 PBR Principles

The Alberta Utilities Commission (AUC) recognized at the outset of its journey to explore alternatives to COSR that PBR can be a *win-win proposition* for all key industry stakeholders. It also understood that reaching an industry consensus on the design/objectives of the PBR plan can be so challenging that it risks derailing efforts to implement PBR altogether. To overcome this obstacle, the AUC forged an industry consensus on a set of principles to inform the design of PBR plans.[47]

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[45] The range of returns over which the regulated firm retains a full dollar for each additional dollar in earnings is referred to as the deadband. For earnings above this range, earnings may be "taxed" in the sense that the regulated firm retains only a portion of each additional dollar in earnings. When this "tax" is high, the regulated firm's incentives to invest in cost-reducing effort are low. This is the case because the regulated firm bears the full cost of cost-reducing effort but retains only a fraction of the benefits. This also explains why economists favor lump-sum taxes on efficiency grounds; the amount of the tax is invariant to the level of earnings or performance and therefore does not negatively affect incentives.

[46] The choice between COSR and PBR is discussed in greater detail in Section 2.9 *infra*.

[47] Alberta Utilities Commission, Regulated Rate Initiative - PBR Principles, Bulletin 2010-20, July 15, 2010.

With a similar purpose in mind, I have provided a set of PBR principles herein that are very similar to those adopted by the AUC.[48] Strict adherence to these principles should serve to inform the design of a sound PBR regime that benefits all key stakeholders. The BC Commission will ultimately determine the precise weight that should be attached to each principle. The PBR principles are listed below followed by a discussion of the rationale for each principle.

PBR Principles

Principle 1.	A PBR plan should create the same efficiency incentives as those experienced in a competitive market while satisfying stipulated service quality and conservation metrics.
Principle 2.	A PBR plan should provide the regulated company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
Principle 3.	A PBR plan should be easy to understand, implement and administer and should result in a streamlined regulatory process.
Principle 4.	The design of the PBR plan should recognize the unique circumstances of each regulated company.
Principle 5.	Customers and the regulated companies should share the benefits of a PBR plan.
Principle 6.	The regulated company should bear limited financial responsibility for events outside of its control.

2.3.1 Principle 1 Rationale (Emulating Competitive Market Incentives)

The first policy statement in PBR Principle 1 recognizes that in serving as a substitute for competition PBR should put in place the same incentives as a competitive market. The regulatory economics literature recognizes that a primary objective of economic regulation is to emulate a competitive market standard. To this end, Professor Alfred Kahn observes that "the single most widely accepted rule for the governance of the regulated industries is regulate them in such a way

48 Principle 6 does not have a counterpart in the AUC's PBR principles but may be subsumed as a corollary to Principle 1. This principle is important and therefore included here because the distinction between exogenous and endogenous events has figured prominently in the design of PBR regimes.

as to produce the same results as would be produced by effective competition, if it were feasible."[49] In similar fashion, Professor James Bonbright observes that "Regulation, then, as I conceive it, is indeed a substitute for competition; and it is even a partly imitative substitute."[50]

An important question concerns precisely what it is that economic regulation seeks to emulate in adopting a competition standard. In the following passage, Professor Bonbright discusses the various attributes of the competition standard and the primacy of dynamic efficiency over static efficiency.

> Under unregulated competition, the price system is supposed to function in two ways with respect to the relationship between the price of the product and the cost of production. In the first place, the rate of output of any commodity will so adjust itself to the demand that the market price will tend to come into accord with production costs. But in the second place, competition will impel rival producers to strive to reduce their own production costs in order to maximize profits and even in order to survive in the struggle for markets. This latter, dynamic effect of competition has been regarded by modern economists as far more important and far more beneficent than any tendency of "atomistic" forms of competition to bring costs and prices into close alignment at any given point of time.[51, 52]

With reference to the design of a PBR regime, this passage underscores the importance of putting in place incentives for firms to invest in product and process innovation rather than focus

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49 Alfred E. Kahn, THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS, Volume I, New York: John Wiley and Sons, 1970, p. 17.

50 James C. Bonbright, PRINCIPLES OF PUBLIC UTILITY RATES, New York: Columbia University Press, 1961, p. 107.

51 *Id.,* p. 53.

52 Static efficiency refers to both consumption efficiency and productive efficiency at a given point in time. Consumption (allocative) efficiency is realized when the last (marginal) unit of output consumed is equal to the resource cost incurred by society in producing it. This is the familiar marginal benefit equals marginal cost condition for optimality. Productive (technical) efficiency is concerned with production at the lowest possible cost. Dynamic efficiency is concerned with the optimal investment over time in capital formation, cost-reducing innovation and product innovation. Dynamic efficiency is particularly critical in infrastructure industries that serve as key drivers of economic growth.

exclusively on the optimal alignment of prices with underlying costs at each point in time.[53] This observation has important implications for the design of a PBR regime.

The second policy statement in Principle 1 recognizes that there is a price and quality dimension to consumer welfare. To wit, consumers are unequivocally better off as a result of the lower prices they pay under PBR relative to COSR when service quality is non-decreasing, *ceteris paribus*. Whereas the regulated firm has strong incentives to reduce costs under PBR, the regulator may harbor concerns that the incentives to reduce costs may result in lower levels of service quality. This explains why most, if not all, incentive regulation plans incorporate some type of service quality benchmarks. In similar fashion, policymakers may have conservation objectives that must be compatible with the PBR regime (e.g., demand-side management).

2.3.2 Principle 2 Rationale (Reasonable Opportunity to Earn a Fair Return)

Principle 2 recognizes that whereas the regulated firm agrees to bear greater risk under PBR, this does not empower the regulator to deny the firm a reasonable opportunity to recover its costs, including a fair return. My understanding is that the legislative framework for implementing PBR in British Columbia provides that electric utilities *must* be given a reasonable opportunity to

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[53] As Professor Joseph Schumpeter has observed,

> A system—any system, economic or other—that at *every* given point of time fully utilizes its possibilities to the best advantage may yet in the long run be inferior to a system that does so at *no* given point of time, because the latter's failure to do so may be a condition for the level or speed of long-run performance (p. 83).
>
> The introduction of new methods of production and new commodities is hardly conceivable with perfect—and perfectly prompt—competition from the start. And this means that the bulk of what we call economic progress is incompatible with it. As a matter of fact, perfect competition is and always has been temporarily suspended whenever anything new is being introduced—automatically or by measures devised for the purpose—even in otherwise perfectly competitive conditions (p. 105).

Joseph A. Schumpeter, CAPITALISM, SOCIALISM AND DEMOCRACY, New York: Harper Torchbooks, 1975 (first published in 1942).

recover their prudent costs and expenses, including a fair return. As a general proposition, the regulator should neither guarantee nor actively preclude the regulated firm from recovering its costs and earning a fair rate of return. The average returns may be comparable across COSR and PBR regimes, but we would expect the variance of returns to be larger in the latter.

2.3.3 Principle 3 Rationale (Administrative Simplicity and Regulatory Efficiency)

Principle 3 recognizes the importance of rules for PBR, including the incentives and reward structure, that are clear, objective and unambiguous. Specifically, it is critical that PBR "promise only what can be delivered and deliver whatever is promised."[54] Paying due deference to these objectives in the design and implementation of PBR should result in reducing the costs of regulation for all key stakeholders, including the regulated firm, consumers and the Commission itself. In addition, rules that are "clear, objective and unambiguous" reduce uncertainty and bolster the credibility of the PBR regime. This is paramount as a lack of credibility in administering the rewards and penalties associated with the PBR regime can undermine its performance.

2.3.4 Principle 4 Rationale (Recognize Unique Circumstances of Regulated Firm)

Principle 4 duly recognizes that regulated firms are likely to be heterogenous and therefore it is incorrect to reflexively presume that PBR is a "one-size-fits-all" proposition (See related discussion in Observation 2 *supra*).[55] This suggests that regulated firms should have some flexibility to position themselves along the PBR continuum in a manner that duly recognizes their unique circumstances. Regulated firms may differ across a number of dimensions, including

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54 David E. M. Sappington, "Designing Incentive Regulation," *Review of Industrial Organization*, Volume 9, 1994, p. 269.

55 See David E. M. Sappington and Dennis L. Weisman, "Seven Myths About Incentive Regulation," in PRICING AND REGULATORY INNOVATIONS UNDER INCREASING COMPETITION AND OTHER ESSAYS, Michael A. Crew, ed., Boston: Kluwer Academic Publishers, 1996, pp. 4-5.

ownership structures, operating environment, customer characteristics, policy priorities and the dynamics of their capital investments. A PBR plan that is carefully calibrated to recognize these differences increases the likelihood that all stakeholder groups can be rendered better off under PBR, consistent with Principle 5.

2.3.5 Principle 5 Rationale (All Stakeholders Should Benefit from PBR)

Principle 5 recognizes that the adoption of PBR represents a change from one "political equilibrium" to another amidst a growing consensus that improvements upon traditional COSR are possible given the experience with incentive regulation across different jurisdictions and industries over time.[56] Principle 3 and Principle 5 taken together recognize that PBR should be designed and implemented with the expectation that all key stakeholder groups, including consumers, the regulated firms and the regulator, are rendered "better off" over the long run relative to COSR. In other words, the adoption of PBR should be a *win-win proposition*.[57]

2.3.6 Principle 6 Rationale (Endogenous vs. Exogenous Events)

The complex and often contentious issue of what is endogenous to the regulated firm (within its control) and what is exogenous to the regulated firm (outside of its control) has figured prominently in the design and structure of PBR plans. Principle 6 recognizes that the regulated

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56 As Thomas Kuhn observed in his classic treatise:

> Political revolutions are inaugurated by a growing sense, often restricted to a segment of the political community, that existing institutions have ceased adequately to meet the problems posed by an environment that they have in part created. . .. Their success therefore necessitates the relinquishment of one set of institutions in favor of another . . .

Thomas Kuhn, *The Structure of Scientific Revolutions*, Chicago: University of Chicago Press, 1962, pp. 92-93.

57 David E. M. Sappington and Dennis L. Weisman, "Seven Myths About Incentive Regulation," In Michael A. Crew, ed., PRICING AND REGULATORY INNOVATIONS UNDER INCREASING COMPETITION AND OTHER ESSAYS, Boston: Kluwer Academic Publishers, 1996, pp. 10-11.

company should not unduly benefit nor be unduly penalized for events outside of its control.[58] Precisely where that line of demarcation should be drawn is not always clear.

Consider, for example, a regulated company that is statutorily required to provide service to all consumers that request it at tariffed rates and subject to minimum quality of service standards. These exogenous constraints on the regulated company may suggest that the company may have limited control of the infrastructure requirements necessary to provide service and yet somewhat more control over how the service is actually provided. Does this imply that there should be a bifurcation in the treatment of CAPEX and OPEX under the PBR plan? Indeed, some PBR plans have treated CAPEX and OPEX differently.[59] A concern, however, is that such disparate treatment can lead to inefficient capital/labor substitution in the firm's production processes.[60] As the OEB observed,

> The Board continues to support a comprehensive approach to rate-setting, recognizing the interrelationship between capital expenditures and OM&A expenditures. Rate-setting that is comprehensive creates stronger and more balanced incentives and is more compatible with the Board's implementation of an outcome-based framework.[61]

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[58] David E. M. Sappington "Designing Incentive Regulation," *Review of Industrial Organization*, Volume 9(3), June 1994, p. 269 (A sound PBR regime should "limit the firm's financial responsibility for factors beyond its control.")

[59] See, for example, John J. Kwoka, "Investment Adequacy Under Incentive Regulation," Northeastern University Working Paper, 2009. A concern with this approach is that it can facilitate inefficient CAPEX-OPEX substitution. Indeed, this is one of the reasons why the Alberta Utilities Commission opted to change the way in which supplemental capital was treated in its second-generation PBR regime. See Alberta Utilities Commission; Decision 21981-D01-2016 (Errata), February 6, 2017, Section 6.

[60] It is noteworthy that the newly adopted approach to PBR in Britain combines the previously separate CAPEX and OPEX indexes into a single index for precisely this reason. See Peter Fox-Penner, Dan Harris and Serena Hesmondhalgh, "A Trip to RIIO in your Future? Great Britain's Latest Innovation in Grid Regulation," *Public Utilities Fortnightly*, Volume 151(10), 2013, pp. 60–65. In addition, both the Alberta Utilities Commission and the Ontario Energy Board have rejected PBR proposals that bifurcate CAPEX and OPEX. See Alberta Utilities Commission, Decision 2012-237, September 12, 2012, Sections 2.3 and 7.3.2.3; and Ontario Energy Board, Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012, pp. 7-9.

[61] Ontario Energy Board, Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012, p. 9.

2.4 Types of PBR Regimes

2.4.1 Overview

There are three basic types of indexed PBR plans that have been employed in the electric power and natural gas sectors. These are (1) price caps; (2) revenue caps and (3) revenue-per-customer caps (which the AUC applies to the natural gas utilities). The trajectory of rates or revenues under these approaches are determined by the previous year's rates/revenues and a formula (equation of motion) that is applied to these rates/revenues. This formula accounts for inflation (*I*-Factor) and an efficiency factor (*X*-factor) along with other factors to account for growth, exogenous events and pass-through provisions. (See the related discussion in Section 2.5 *infra*.) The growth factor in the PBR formula recognizes that output changes, both the number of customers and volumes, is exogenous to the regulated firm.

All three approaches to indexed PBR plans can be expected to put in place more high-powered incentives relative to traditional COSR. A notable difference between revenue caps and revenue-per-customer caps is that a revenue cap may not allow revenue to change with customer growth. This implies that under a revenue cap the regulated company may bear the financial risk associated with customer growth.

The BC Commission adopted a revenue cap PBR regime for Fortis BC with a term of 6 years. The plan employs an input (wholesale) measure of inflation and includes an earnings sharing mechanism. The Commission referred to this PBR plan as a "building blocks" approach because separate revenue caps are employed for growth capital, sustainment and other capital and O&M.[62]

[62] See British Columbia Utilities Commission, In the Matter of FortisBC Energy Inc., Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018, Decision, September 15, 2014, p. 21.

The Commission adopted *X* factors (inclusive of the stretch factors) of 1.03 and 1.10 for FBC and FEI, respectively.[63]

In its second-generation PBR regime, Alberta retained price caps for the electricity distribution utilities but continued to allow the natural gas utilities to operate under a revenue-per-customer cap. This disparate treatment is explained by the fact that the electricity providers have yet to report the negative growth that the natural gas providers have experienced. In addition, at least to date, conservation initiatives would not appear to have the same urgency in Alberta as they do in some other jurisdictions.[64] All of the electricity utilities in Alberta are subject to the same general price cap formula (e.g., *X* factor and stretch factor), but supplemental capital is treated separately for each utility.

Ontario is in its fourth-generation PBR regime. Unlike the AUC, the OEB has adopted the so-called menu approach to PBR in that the distribution utilities may choose between three different regulatory regimes.[65] The OEB has adopted a price cap approach to PBR for electricity distributors and a revenue cap approach for transmission providers.[66] Unlike the AUC, the OEB has made more extensive use of statistical benchmarking. This approach essentially ratchets upward

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63 *Id*., p. 91.

64 There is some evidence to suggest that this may change going forward. On March 29, 2017, the lieutenant-governor for the province of Alberta issued Order in Council 120/2017 ordering the Alberta Utilities Commission to inquire into, and report to, the Minister of Energy on matters relating to alternative and renewable Electric Distribution System-Connected Generation. See the following URL. http://www.qp.alberta.ca/documents/orders/Orders_in_Council/2017/317/2017_120.pdf. On March 31, 2017, the AUC initiated Proceeding 22534 to respond to this Order.

65 The large number of electricity distributors (77) in Ontario that perform under different operating conditions likely explains the menu approach. Ontario Energy Board, Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012, p. 1. Also, whereas the menu ("options") approach has some desirable efficiency properties in theory, it has encountered some implementation difficulties. See, for example, David E. M. Sappington, "Designing Incentive Regulation," *Review of Industrial Organization*, Volume 9(3), June 1994, pp. 245-272.

66 Ontario Energy Board, Handbook for Utility Rate Applications, October 13, 2016, Section 6.

(downward) the trajectory of prices/revenues based on the measured efficiency of the individual utility relative to its peer group. More efficient utilities are rewarded with a faster rate of growth in prices/revenues, whereas less efficient utilities are penalized with a slower rate of growth in prices/revenues. The benchmarking issue is examined further in Section 4 below.

A jurisdiction-by-jurisdiction survey of PBR in North America is beyond the scope of this report. Nonetheless, a review of the literature reveals that both price cap and revenue cap approaches to PBR are most common. The PBR plans vary across a number of different dimensions, including (1) the *X* factor, (2) length of the plan; (3) provisions for supplemental capital, (4) offramps/reopeners, and (5) earnings sharing mechanisms.

2.4.2 PBR for Vertically-Integrated Utilities

The production of electricity can be partitioned into three basic components: generation, transmission and distribution.[67] In some jurisdictions these components are unbundled, whereas in others the utility provides only a bundled retail service offering. Each production component can be regulated via PBR, COSR or competition. Consider, for example, the case of EPCOR in Alberta. The company provides distribution, which is subject to PBR, and transmission that remains under traditional COSR. The distribution and transmission function are structurally separated. The electric utilities in Alberta are statutorily prohibited from participating in the competitive generation market. The combination of regulatory regimes and competition for the various elements of production in the case of EPCOR in Alberta is illustrated in Table 1.

[67] Retailing/Billing is sometimes included as a separate component of production, but we abstract from that complexity here in the interest of economy of presentation.

Regulatory Regime / Production Element	COSR	PBR	Competition
Generation			√
Transmission	√		
Distribution		√	
Bundled Retail Service	n.a.	n.a	n.a

Table 1. EPCOR Combination of Regulatory Regimes and Production Elements

EPCOR may well propose that transmission, like distribution, be subject to PBR rather than COSR, or the AUC may mandate such an outcome as it did in the case of distribution. The specific attributes of each element of production may give rise to either a different form of PBR (price caps versus revenue caps) or specific design attributes for the PBR regime. For example, generation is typically characterized by more "lumpy" capital investments and this may require special provisions for capital within the PBR regime (e.g., capital trackers).[68] Conversely, the generally smoother investment profiles commonly associated with transmission and distribution elements may allow for a more limited scope of special provisions for capital in the PBR regime.

It is instructive to briefly consider the case where the individual elements of production are not unbundled, and the utility sells only a bundled retail service offering. In principle, the mechanics of PBR are no different than in the unbundled case. The primary difference that would

68 This observation notwithstanding, more efficient, interconnected power markets combined with the emergence of new technologies for producing power and distributed generation may have a mitigating effect on the scope of these special provisions. For a discussion of the role of distributed energy resources in reducing utility investments, see Mason Willrich, MODERNIZING AMERICA'S ELECTRICITY INFRASTRUCTURE, Cambridge MA: The MIT Press, 2017, chapters 9–11; and Steven W. Blume, ELECTRIC POWER SYSTEM BASICS FOR THE NONELECTRICAL PROFESSIONAL, Second Edition, Hoboken, NJ: John Wiley and Sons. 2017, pp. 196-99.

arise would be in the specific asset classes that are combined for the PBR regime and the associated productivity factors (discussed below) that should apply in calibrating the trajectory of prices over the course of the PBR regime.

2.5 The PBR Alphabet[69]

Price cap regulation is commonly referred to as "*I* – *X*" regulation because the maximum annual increase in the regulated firm's average prices is capped by an inflation index (*I*) less a productivity offset (*X*).[70, 71] The "*I* – *X*" price adjustment formula follows from the basic idea that in a competitive market (which economic regulation seeks to emulate), average productivity gains are passed on to consumers in the prices that they pay for service after controlling for inflation.[72] In order to preserve ideal incentives for efficiency it is necessary for the regulated firm to perceive that the *X* factor does not vary with its own performance so there is no ratchet effect.[73] This is

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69 The analysis in this section applies to revenue cap regulation as well price cap regulation.

70 See Jeffrey Bernstein and David Sappington, "Setting the X Factor in Price Cap Regulation Plans," *Journal of Regulatory Economics*, Volume 16(1), July 1999, pp. 5-25.

71 In Canada and the United States, the *X* factor is typically set to reflect expected industry productivity growth. Whereas, in Europe, the *X* factor tends to be more of a "negotiated value." See Stephen Littlechild, REGULATION OF BRITISH TELECOMMUNICATIONS' PROFITABILITY, Department of Industry: Report to the Secretary of State, 1983; and Michael Crew and Paul Kleindorfer, "Incentive Regulation in the United Kingdom and the United States: Some Lessons," *Journal of Regulatory Economics,* Volume 9(3), 1996, pp. 211-225.

72 *X* is not independent of *I*. Specifically, *I* in the PBR formula can be an economy-wide or industry-specific measure of inflation. When *I* is an industry-specific measure of inflation, *X* is equal to an appropriate measure of industry productivity growth. When *I* is an economy-wide measure of inflation, *X* is comprised of two separate components. The first component is the difference between industry productivity growth and economy-wide productivity growth. The second component is the difference between economy-wide input price growth and industry-specific input price growth. For further discussion, see Mark E. Meitzen, Phillip E. Schoech and Dennis L. Weisman, "The Alphabet of PBR in Electric Power: Why X Does Not Tell the Whole Story," *The Electricity Journal*, Volume 30(8), October 2017, pp. 30-37.

73 This suggests that data on the firm's own performance can be used in the development of the *X* factor provided that (i) these data are not used repeatedly over time; and (ii) the endpoint of the data series employed in the analysis predates the announcement that the data would be used for such purposes. See generally Andrei Schleifer, "A Theory of Yardstick Competition," *Rand Journal of Economics*, Volume 16(3), 1985, pp. 319-327.

sometimes referred to as the *immutability condition*. Moreover, provided that the X factor is developed on the basis of sound economic principles and does not undermine the financial viability of the enterprise, the incentives for efficiency are invariant to both the sign and magnitude of the X factor.[74]

PBR formulae also typically incorporate Z factors, which allow the rate adjustment formulae to reflect one-time, exogenous events beyond the regulated firm's control that are not fully reflected in the other parameters of the rate adjustment formula (e.g., changes in tax/environmental policy). In addition, it is common in PBR plans to include a stretch factor (S) in the rate adjustment formula to reflect the increased productivity growth that is expected from the change from traditional COSR to PBR.[75] This stretch factor is sometimes referred to as a consumer productivity dividend because it is an *ex ante* productivity growth increment that confers upon consumers greater real price reductions or a slower rate of price growth. Hence, the annual rate adjustment formula can be expressed by

(1) $\%\Delta P = I - X - S + Z,$

where $\%\Delta P$ is the annual (maximum) percentage change in price.[76]

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[74] Luis M.B. Cabral and Michael H. Riordan, "Incentives for Cost Reduction Under Price Cap Regulation," *Journal of Regulatory Economics*, Volume 1, 1989, pp. 93-102. The basic idea is that a regulated firm subject to an unachievable X factor will come to the realization that no amount of effort can render it financially viable. Under these conditions, the regulated firm essentially gives up which triggers a PBR reopener or the filing of a traditional rate case. This observation underscores the important point that consumers are not necessarily rendered better off with a high X factor.

[75] Stretch factors were typically not retained for second-generation incentive regulation plans in telecommunications, but the same cannot be said for PBR plans in electric distribution. The difference is likely explained by (i) more limited competition; and (ii) supplemental capital mechanisms that may retain elements of COSR in electricity distribution.

[76] In the case of revenue (R) caps, $\%\Delta R$ would replace $\%\Delta P$ on the left-hand side of (1).

The above formula is typical of that applied in the telecommunications industry. In the electric power industry, however, capital expenditures have tended to be a challenge for utilities in that the standard price cap formula, premised on a non-negative *X* factor and declining real rates, may not generate sufficient revenues to adequately fund required infrastructure improvements. Hence, it is increasingly common in the electric power industry to include a supplemental capital factor (*K*) in the PBR formula.[77] The PBR formula may also include a Y factor to account for recurring expenditures over which the utility has no control (e.g., transmission charges) and therefore the utility is allowed a full pass-through. The revised rate adjustment formula is given by

(2) $\%\Delta P = I - X - S + Z + K + Y.$

One additional parameter is the term of the PBR plan or the number of years prior to rebasing (i.e., the true-up of rates to a target rate-of-return at the end of the PBR regime).[78] While there is considerable variability in the terms of the PBR plans, 4-6 years is common, with an average of approximately 5 years. It is generally recognized that the longer the term of the PBR plan, the stronger the incentives for efficiency, *ceteris paribus*.[79]

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77 A survey of the various methods by which capital has been addressed in PBR regimes is provided in the following. David E. M. Sappington and Dennis L. Weisman, ASSESSING THE TREATMENT OF CAPITAL EXPENDITURES IN PERFORMANCE-BASED REGULATION PLANS, Attachment 2 to the direct evidence of Dennis L. Weisman (Appendix A) on behalf of EPCOR Distribution & Transmission, Inc. Proceeding 201414, Next Generation PBR Proceeding, Alberta Utilities Commission, March 23, 2016.

78 In contrast to COSR, rebasing under PBR occurs at discrete intervals. As a result, PBR can result in "rate shock" when rebasing occurs at the end of the PBR term. Consumers are likely to react more negatively to a one-time significant rate change relative to a series of small rate changes even if the terminal rate levels are the same. Hence, the absence of rate smoothing under PBR is a potential concern. See R. Mark Isaac, "A Case Study of Some Pitfalls of Implementation," *Journal of Regulatory Economics*, Volume 3(2), 1991, pp. 193-210.

79 For a discussion of the relevant tradeoffs in setting the length of the price cap plan, see David E. M. Sappington, "Price Regulation" in HANDBOOK OF TELECOMMUNICATIONS ECONOMICS, Martin Cave, Sumit Majumdar, and Ingo Vogelsang, eds., Amsterdam: North-Holland, 2002, Chapter 7, pp. 251-252.

Two other mechanisms may accompany PBR—earnings sharing mechanisms and efficiency carryover mechanisms. These two mechanisms are discussed in the following two subsections, respectively.

2.6 Earnings Sharing Mechanisms

Regulators may have concerns that under a PBR plan the financial returns of the utility may exceed or fall short of target levels. As a result, PBR plans may include earnings sharing mechanisms (ESMs) that ensure that the utility's returns remain within "acceptable bounds." The use of ESMs has tended to vary across industries, jurisdictions and time. ESMs were common in the first-generation of indexed incentive regulation plans in the telecommunications industry in the United States, but the CRTC (Canadian Radio-television and Telecommunications Commission) never adopted ESMs for Canadian telecommunications carriers.[80] ESMs have tended to have greater longevity with PBR plans in the electricity and natural gas sectors. One possible explanation for this phenomenon is that retail competition has been slower to develop in these sectors relative to telecommunications and regulators believed that retaining ESMs was necessary to provide the proper safeguards.

A hypothetical ESM with a deadband set around the target rate of return of 10% is illustrated in Figure 2. This figure illustrates the relationship between the company's unadjusted earnings (which are the company's earnings if prices remain at the levels established at the start of the PBR

[80] See David E. M. Sappington and Dennis L. Weisman, "Price Cap Regulation: What Have We Learned from Twenty-Five Years of Experience in the Telecommunications Industry?" *Journal of Regulatory Economics*, Volume 38(3), December 2010, pp. 227–257; and David Sappington, Johannes Pfeifenberger, Phillip Hanser, and Gregory Basheda, "Status and Trends of Performance-Based Regulation in the U.S. Electric Utility Industry," *The Electricity Journal*, Volume 14(8), October 2001, pp. 71–79.

plan) and the company's authorized earnings (which are its earnings after any price adjustments that are undertaken to implement the specified sharing of earnings).

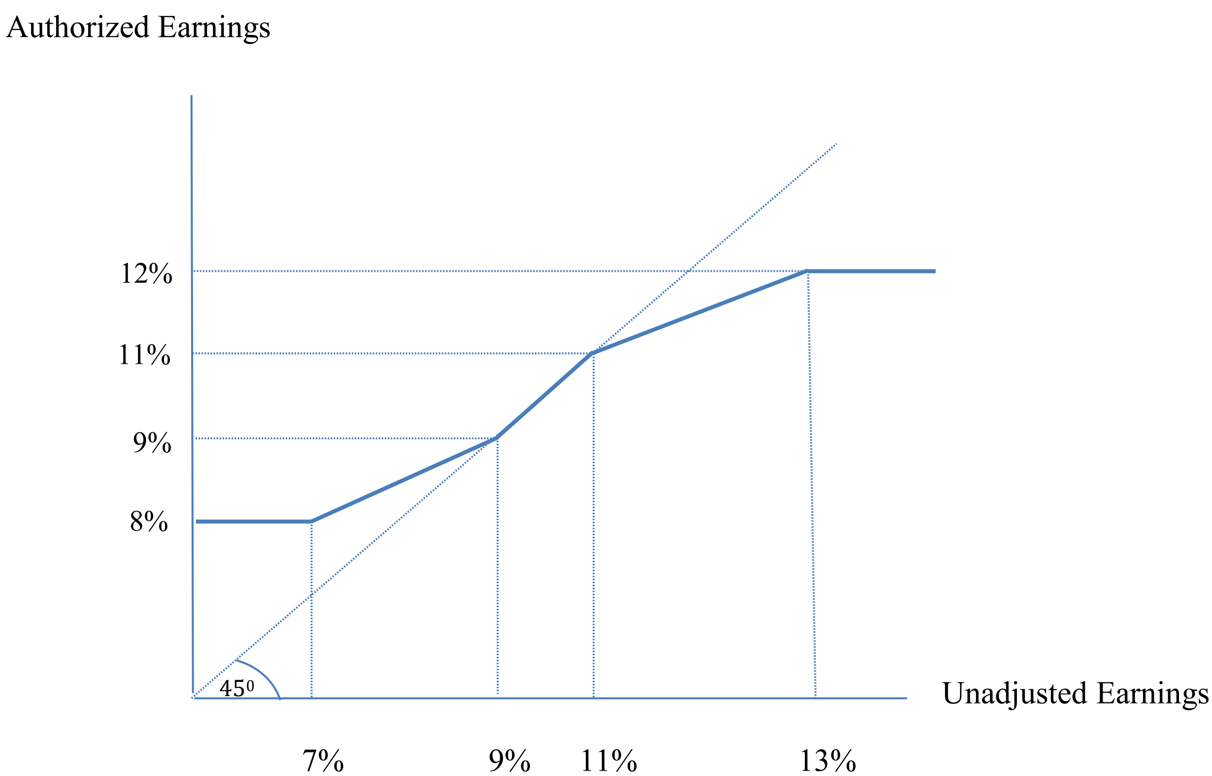

Figure 2. Earnings Sharing Mechanism

Under the hypothetical ESM illustrated in Figure 2, the company's authorized earnings coincide with its unadjusted earnings when these earnings are between 9% and 11%.[81] As unadjusted earnings increase between 11% and 13%, the company and its customers each receive

[81] Figure 2 reflects this coincidence of earnings with the solid line segment that has a slope of 1 for unadjusted earnings between 9% and 11%, the so-called deadband.

one half of the incremental earnings.[82, 83] The company is not permitted to earn more than a 12% return on investment. As unadjusted earnings decline below a 9% return on investment toward a 7% return on investment, prices are increased sufficiently to ensure the company and its customers share the incremental decline in earnings equally.[84] Prices are further increased, as necessary, to ensure the company's earnings never fall below an 8% return on investment in this example.

There are valid arguments both for and against including ESMs in PBR plans. The advantages are three-fold in nature. First, ESMs may ensure that earnings remain within "acceptable bounds." Second, ESMs may be structured to ensure that service rates do not diverge too far from efficient levels. Third, ESMs can serve as a type of "safety valve" that mitigates the political pressure on the regulator to recontract, perhaps even terminate the PBR plan, when the earnings of the regulated firm approach levels that consumers deem unacceptable. ESMs align the interests of consumers with those of the regulated firm because they return a share of any excess earnings to consumers. As a result, consumers are less likely to view the regulated firm's excess earnings as a signal that their rates are too high. ESMs serve to preserve the stability of the PBR regime precisely because they reduce the likelihood of regulatory recontracting.

> Political support for a policy can be garnered when consumers benefit financially in direct, visible ways precisely when the regulated firm benefits, as is the case under earnings-sharing plans. Widespread political support for a policy can ensure its long-

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82 Note that the sold line segment that appears above adjusted earnings between 11% and 13% in Figure 2 has a slope between 0 and 1. The slope captures the explicit sharing of incremental earnings by the company and its customers. The larger is this slope, the larger is the fraction of incremental earnings that is awarded to the company (i.e., the lower is the "earnings tax").

83 The relevant portion of incremental earnings can be awarded to consumers in different ways. For instance, the prices charged to customers might be reduced. Alternatively a bill credit might be awarded to all customers at the end of the year. The incremental earnings might also be employed to create or expand a program aimed at particular policy objectives (e.g., rate relief for low-income customers).

84 The fraction of incremental earnings awarded to the company can be explicitly linked to the level of service quality the company delivers or its compliance with conservation metrics. Such linkages can help to ensure that the company does not increase its earnings by allowing service quality to deteriorate or by failing to comply with conservation metrics.

> term survival and thus a continued flow of benefits to all parties. A sustained flow of moderate gains can often serve all parties better than can a short-lived spurt of particularly large gains.[85]

Whereas the rationale for incorporating ESMs into PBR plan may appear sound, significant problems have arisen with ESMs in practice. As a result, there can be no guarantee that consumers are necessarily better off with PBR plans that incorporate ESMs. The expected benefits of ESMs (e.g., consumer safeguards) must be objectively weighed against their expected costs (e.g., reduced incentives and strategic behavior).

First, an ESM can blunt incentives for efficiency. To see this, recognize that a rational, profit-maximizing utility will invest in cost-reducing effort up to the point where the marginal benefit of cost-reducing effort is equal to the marginal cost of cost-reducing effort. This means that a utility that retains only 50 cents of each additional dollar of cost-savings will invest less in cost-reducing effort than a utility that retains a full dollar of each additional dollar of cost-savings, *ceteris paribus*.[86]

This characteristic of ESMs has two adverse consequences. First, the cost-savings that are passed on to consumers at the end of the PBR regime at the time of re-basing will typically be less than if there were no ESMs. Second, as a theoretical matter, a utility operating under a PBR plan with an ESM should face a lower X factor than a utility operating under a PBR plan without an

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[85] David E. M. Sappington and Dennis L. Weisman, DESIGNING INCENTIVE REGULATION FOR THE TELECOMMUNICATIONS INDUSTRY, Cambridge MA: The MIT Press, 1996, p. 334.

[86] This distortionary effect would not arise if the profits shared were independent of the regulated company's actual performance (i.e., a lump sum tax). This observation has important implications for the discussion of PBR for crown corporations in Section 5.

ESM.[87] This implies that the rate trajectory will typically be higher under a PBR plan with an ESM relative to a PBR plan without an ESM.

Second, ESMs can give rise to incentives for "gaming" on the part of both regulators and utilities. Suppose that the ESM enables the utility to retain each additional dollar of cost-savings for returns between 9% and 11%. However, the utility retains only 50 cents of each additional dollar of cost savings for returns greater than 11%. The regulator may have an incentive to micromanage the utility's operations or strategically disallow costs to move the utility's returns into the sharing range.[88] The regulator would have no such incentive if there were no ESM (i.e., pure price (revenue) cap regulation). Similarly, the utility may have incentives to strategically defer investments or the timing of when it books specific costs to avoid the "earnings tax" and the sharing of excess returns with consumers. Hence, ESMs can elicit strategic behavior on the part of both regulators and utilities that reduce the expected benefits of PBR.

Third, formal empirical analyses of the performance of incentive regulation in the U.S. telecommunications industry when ESMs were still prominent revealed relatively modest gains

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[87] The Federal Communications Commission explicitly recognized this tradeoff in the design of the price cap plans for the Regional Bell Operating Companies. See Federal Communications Commission, CC Docket No. 91-41, LEC Price Cap Performance Review, April 7, 1995.

[88] A possible example of this phenomenon occurred in the aftermath of epic floods that plagued the Midwest in the summer of 1993. After scrutinizing how Southwestern Bell allocated its resources in responding to this natural disaster, the Missouri Public Service Commission ordered cost disallowances that had the effect of moving the company's financial returns from the non-sharing range to the sharing range. These events prompted Southwestern Bell to move expeditiously across its five states with initiatives to eliminate earnings sharing from its price cap regulation plans.

relative to traditional COSR.[89] This is not surprising given that earnings sharing retains many of the same features as traditional COSR.[90, 91]

Fourth, a key observation is that ESMs keep the regulator in the business of evaluating the prudence of the regulated firm's decision-making. This is problematic because the informational asymmetries between the regulator and the regulated firm increase concomitantly with the complexities of the industry going forward.[92]

Evaluating the various economic arguments both for and against earnings sharing, the weight of the evidence does not support including a traditional ESM in a PBR plan. The net economic gains from replacing COSR with PBR that includes earnings sharing are likely to be small.[93] Whereas regulators, consumer groups and sometimes even regulated firms may be comforted by

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89 To date, there have been no peer-reviewed, published, comprehensive econometric analyses of the relative performance of PBR and COSR in the electricity or natural gas industries.

90 See Donald J. Kridel, David E. M. Sappington, and Dennis L. Weisman, "The Effects of Incentive Regulation in the Telecommunications Industry: A Survey," *Journal of Regulatory Economics,* Volume 9(3), 1996, pp. 269–306; and Jaison R. Abel, "The Performance of The State Telecommunications Industry Under Price-Cap Regulation: An Assessment of The Empirical Evidence," NRRI 00-14, The National Regulatory Research Institute, September 2000.

91 The theoretical economics literature indicates that earnings sharing may [actually] provide for enhanced levels of economic welfare relative to pure price cap regulation in the presence of limited information on the part of the regulator. See Mark Armstrong and David Sappington, "Recent Developments in the Theory of Regulation," in THE HANDBOOK OF INDUSTRIAL ORGANIZATION, M. Armstrong & R. Porter eds., Amsterdam: North-Holland, Volume 3, 2007, pp. 1557-1700; Thomas Lyon, "A Model of Sliding Scale Regulation," *Journal of Regulatory Economics*, Volume 9(3), May 1996, pp. 227-247; and Richard Schmalensee, "Good Regulatory Regimes," *Rand Journal of Economics*, Volume 20(3), Autumn, 1989, pp. 417-436. Notably, these studies do not account for the myriad strategic problems with earnings sharing in practice (e.g., cost-shifting, cost-misreporting, abuse, etc.), nor do they account for the "costs of regulation" associated with administering ESMs which may be comparable to COSR.

92 See Professor Kahn's prescient discussion of this matter at note 4 *supra*.

93 This conclusion is based, in part, on the empirical analysis of price cap regulation with earnings sharing in the U.S. telecommunications industry. See notes 90 and 91 *supra*. Moreover, it can be shown that many of the desirable efficiency properties of pure price cap regulation break down under earnings sharing. See, for example, Dennis L. Weisman, "Superior Regulatory Regimes in Theory and Practice," *Journal of Regulatory Economics*, Volume 5(4) 1993, pp. 355-366.

the "safety net" that earnings sharing provides,[94] it is the very presence of that "safety net" that undercuts the performance of PBR.

Furthermore, this so-called "safety net" may prove illusory for the regulated firm. To see this, recognize that the regulator may have incentives to strategically disallow costs in order to move earnings (i) into the sharing range (and secure rate decreases) when unadjusted earnings are near the upper end of the deadband and (ii) into the deadband (and avoid rate increases) when unadjusted earnings are outside the lower end of the deadband.[95] The net effect would be to increase the risk borne by the regulated firm because the probability of high returns is decreased while the probability of low returns is increased.

The significant resources required to design and implement a PBR regime with earnings sharing would be difficult to justify when the expected benefits in terms of improved efficiency and innovation are so limited. The following quotation from a former chairman of the Massachusetts Commission is instructive.

> The [Massachusetts regulatory] commission decided that earnings sharing was not appropriate because it introduces many of the cost-of-service disincentives for efficiency that price cap regulation is designed to eliminate. The commission also did not want to have to rule on the prudence of investments in an increasingly risky and speculative industry, which would have been required for an earnings calculation.

[94] See note 88 *supra*. This parallels a related problem with COSR (capping returns on successful investments while disallowing costs on unsuccessful investments). See Lawrence A. Kolbe and William B. Tye, "The Duquesne Opinion: How Much 'Hope' is There for Investors in Regulated Firms?" *Yale Journal on Regulation*, Volume 8(1), Winter 1991, pp. 113-157.

[95] There is some evidence to indicate that regulators adopt more liberal ("pro-competitor") entry policies under pure price cap regulation *vis-à-vis* earnings-based regulatory regimes. Without earnings sharing, the regulator has no vested interest in the earnings of the regulated firm and therefore tends to view competitive entry more favorably (i.e., regulatory moral hazard). Conversely, under COSR or price cap regulation with earnings sharing, competitive entry can place upward pressure on politically sensitive service rates. See Dale E. Lehman and Dennis L. Weisman, "The Political Economy of Price Cap Regulation," *Review of Industrial Organization*. Volume 16, 2000, pp. 343-356.

> Also, earnings sharing would require an annual review of earnings, which the Commission thought would be a significant administrative burden.[96, 97]

The above observations notwithstanding, it is conceivable that some of these concerns may be mitigated if PBR with earnings sharing is merely a transitional regulatory regime that represents an intermediate step along a dynamic path toward pure PBR. This was the case with incentive regulation in the U.S. telecommunications industry.[98] The outstanding question is whether such an intermediate step is warranted in light of the decisions of other Canadian regulatory commissions to forego earnings sharing for both electric power and telecommunications companies.

Finally, it is noteworthy that the AUC explicitly rejected earnings sharing in both its first-generation and second generation PBR plans for the electric power and natural gas industry.[99] As an alternative, the AUC adopted a reopener in the PBR regime that is triggered when returns deviate from target levels by +/- 300 basis points in two consecutive years or by +/- 500 basis points in any one year.[100] The OEB has adopted a similar approach.[101] When the utility perceives that the probability of triggering these reopeners is negligible, which it will be with a sufficiently wide deadband, it will have virtually the same incentives for superior performance as if it were

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96 Paul Vasington, "Incentive Regulation in Practice: A Massachusetts Case Study," *Review of Network Economics,* Volume 2(4), 2003, p. 459.

97 It is also important to recognize that earnings sharing in a PBR regime may prove difficult to reconcile with PBR Principles 1 and 3.

98 See David E. M. Sappington and Dennis L. Weisman, "Price Cap Regulation: What Have We Learned from Twenty-Five Years of Experience in the Telecommunications Industry?" *Journal of Regulatory Economics*, Volume 38(3), December 2010, pp. 227–257.

99 Alberta Utilities Commission, Decision 2012-237, Rate Regulation Initiative Distribution Performance-Based Regulation September 12, 2012 Section 8; and Alberta Utilities Commission, Decision 20414-D01-2016 (errata), 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, February 6, 2016, Section 7.

100 Alberta Utilities Commission, Rate Regulation Initiative Distribution Performance-Based Regulation, September 12, 2012, Decision 2012-237, Section 8.1.1.

101 Ontario Energy Board, Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012, p. 13.

operating under a pure PBR regime. Nonetheless, sufficient earnings safeguards remain in place should returns diverge too far from target levels.

2.7 Efficiency Carryover Mechanisms

It is standard practice for a PBR plan to be reviewed after some stipulated period of time. This review may be limited to a reexamination of the parameters of the price (revenue) cap formula, such as the *X* factor, or entail a recalibration of the regulated firm's rates to achieve a target rate of return. In an important sense, recalibrating rates to achieve a target rate of return gives rise to efficiency distortions and possibly strategic behavior, including cost-shifting, not unlike those associated with ESMs. The regulated firm will have less than ideal incentives to innovate and discover efficiencies if it believes that the regulator will simply claw back these efficiency gains at the end of the PBR regime and pass them on to consumers in the form of lower rates. These adverse incentives are particularly pronounced toward the end of the PBR regime.

The efficiency carryover mechanism (ECM) is the construct designed to address this issue. An ECM allows the regulated firm to carry over a portion of its efficiency gains (losses) into the next PBR regime. With an ECM there is not a full true-up of rates to achieve a stipulated target rate of return at the end of the PBR term. There are countervailing incentives that should be considered. A full true-up of rates to a target rate-of-return provides weaker incentives for cost reduction, but also decreases the period of time over which prices may diverge (sub-optimally) from incremental cost. A partial true-up of rates to a target rate-of-return provides stronger incentive for cost-reduction, but also increases the period of time over which prices may diverge (sub-optimally) from incremental cost. Hence, the less complete the true-up of earnings at the end of the PBR regime, the more high-powered the regulatory regime and the stronger the firm's incentives to invest in cost-reducing innovation.

Suppose, for example, that the target rate of return (T-ROR) is 10% and the average rate of return (A-ROR) is 12% as measured over the course of the PBR regime. The ECM may be recalibrated at the beginning of the next PBR regime to achieve a T-ROR of 11% = 10% + ½ × (12% – 10%), where ½ or 50% is the adjustment percentage. Hence, the ECM enables the regulated firm to carryover a portion of its realized efficiency gains into the next PBR regime. The efficiency carryover may be limited to a stipulated number of years into the next PBR regime. Whether the ECM should be symmetric with respect to the sharing of excess or deficient returns would depend, in part, on how the other parameters of the PBR regime are calibrated and their particular risk-bearing properties.

It is instructive to examine the specific properties of this type of ECM. First, in the case of a 100% adjustment, there is a full true-up of rates to a target rate of return at the end of the PBR regime. Conversely, when the adjustment is less than 100% there is not a full true-up of rates at the end of the PBR regime. This means that when the regulated firm is successful in its pursuit of efficiencies, the ECM ensures that it will not be required to surrender all of those efficiency gains at the end of the PBR regime. Conversely, if the regulated firm is less than successful in its quest for efficiencies, the ECM ensures that it will not be made "whole" at the end of the PBR regime. In this manner, the ECM enlists both "carrots" and "sticks" to provide strong incentives for superior performance.

Second, in terms of the various efficiency tradeoffs, an adjustment closer to 100% places proportionately greater weight on static efficiency, properly aligning prices with underlying economic costs, and proportionately less weight on dynamic efficiency. Conversely, an adjustment closer to 0% places proportionately greater weight on dynamic efficiency, encouraging investment in product and process innovation, and proportionately less weight on static efficiency.

Third, incorporating an ECM into the PBR framework is consistent with PBR Principle 1 in that, depending on the value of the adjustment percentage, it can serve to "create the same efficiency incentives as those experienced in a competitive market . . ." That is to say, an ECM with an adjustment of less than 100% strengthens incentives for dynamic efficiency because the regulated firm would not be forced to surrender the entirety of its efficiency gains at the end of PBR regime. An ECM is also consistent with PBR Principle 5 in that "Customers and the regulated companies should share the benefits of a PBR plan." The sharing with an ECM occurs on an *ex post* or retrospective basis, whereas the sharing associated with the *X* factor and the stretch factor occurs on an *ex ante* or prospective basis.

2.8 Offramps and Reopeners

Offramps and reopeners are typically included in PBR plans as a safeguard against unexpected results that may render the continued operation of the PBR plan untenable.[102] The difference between an offramp and a reopener relates to the scope of the inquiry.

A reopener may be included in a PBR plan to address specific problems with the design or operation of a PBR plan that may arise over the course of the PBR plan. These specific problems may have a material impact on either the company or its customers that cannot be addressed through the various elements of the plan (*Z* factors, *Y* factors, etc.).

An off-ramp is similarly intended to serve as a safeguard against unexpected results in the operation of the PBR plan. Off-ramps differ from re-openers in that once triggered the entirety of the PBR plan is examined and possibly terminated. In contrast, a re-opener is generally intended to provide an opportunity to investigate and modify a specific component in the operation or design of the PBR

[102] See, for example, Alberta Utilities Commission, Rate Regulation Initiative Distribution Performance-Based Regulation September 12, 2012 Decision 2012-237, Section 8.

plan. Candidates for reopeners include (i) deficient/excess financial returns; (ii) material deterioration in service quality; and (iii) change in size of service territory.

2.9 The Choice Between COSR and PBR

As discussed above, a central question in the economics of regulation literature concerns whether earnings-based regulatory regimes, price-based regulatory regimes, or a combination of regulatory regimes are the best means to replicate the discipline of competitive markets. Professors Armstrong and Sappington offer the following perspective on the tradeoffs between the two principal types of regulatory regimes.

> Regulatory policy can affect infrastructure investment differently than it affects innovative effort and investment designed to reduce operating costs. To illustrate this point, first consider rate of return regulation, which promises a fair return on prudently incurred investment. When expropriation can be avoided, such a promise can deliver strong incentives for infrastructure investment. In contrast, because it requires revenues to track costs closely, rate of return regulation (like other forms of "cost-plus" regulation) typically provides limited incentive for innovation and cost reduction.
>
> Now consider price cap regulation, which typically permits revenues to diverge from realized costs for a specified period of time (e.g., four years) but does not promise specific long-term returns on investment. Although such a policy can provide substantial incentive for short-term innovation and cost reduction, it may provide limited incentive for long-term infrastructure investment. Therefore, the choice between rate of return regulation and price cap regulation will depend in part on the type of investment that is most important to secure. In settings where the top priority is to induce the regulated firm to employ its existing infrastructure more efficiently, price cap regulation may be preferable. In contrast, in settings where it is important to reverse a history of chronic underinvestment in key infrastructure, rate of return regulation may be preferable (footnotes omitted).[103]

To foreshadow the discussion in the next section, when regulatory commitment to the basic tenets of PBR is weak COSR may be expected to perform better than PBR.

> The appropriate choice between rate of return regulation and price cap regulation also is influenced by industry volatility and regulatory commitment powers. As costs and

[103] Mark Armstrong, and David E. M. Sappington, "Regulation, Competition and Liberalization," *Journal of Economic Literature*, Volume 44, June 2006, pp. 340-41 (footnotes omitted).

> demands change over an extended time period, prices and costs will invariably diverge under price cap regulation, possibly leading either to financial distress or to particularly large profit for the regulated firm. Neither of these outcomes is likely to be credibly sustained in settings where the country's institutions are weak. Therefore, in such settings, rate of return regulation may be preferable to price cap regulation in the presence of considerable industry volatility, particularly if infrastructure investment is desirable. The cost-plus nature of rate of return regulation, which ensures profits are neither excessive nor insufficient, can render its implicit commitment to set prices that track costs closely more credible than the price commitments encompassed in a price cap plan.[104]

The above passages may be construed to suggest that a bifurcated PBR plan is optimal, one that administers CAPEX under COSR and OPEX under price (revenue) caps. In fact, there have been proposals for just such an approach to PBR.[105] The problem with this silo-approach, however, is that it may foster inefficient capital-labor substitution that risks undermining the superior efficiency properties of PBR. This is one of the primary reasons that the AUC significantly modified the way supplemental capital is treated in its second-generation PBR regime.[106] Similar objectives underlie the changes to PBR in the United Kingdom.[107]

The treatment of capital in the design of PBR plans in the electricity sector has confounded regulators in North America. The AUC, the OEB and the BC Commission have all struggled with

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[104] *Id.,* p. 341 (footnotes omitted).

[105] See, for example, John J. Kwoka, "Investment Adequacy Under Incentive Regulation," Northeastern University Working Paper, 2009.

[106] There was protracted debate among the parties in that proceeding as to whether the capital tracker approach that the AUC had adopted for supplemental capital in the first-generation PBR regime had led to overcapitalization along the lines of the familiar Averch-Johnson effect typically associated with COSR. Harvey Averch and Leland L. Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review*, Volume 52(5), September 1962, pp. 1052-1069. Despite the theoretical prediction of an overcapitalization bias, the empirical support for the Averch-Johnson effect is relatively weak. See, for example, Paul L. Joskow, "Regulation and Deregulation After 25 Years: Lessons for Research in Industrial Organization," *Review of Industrial Organization*, 2005, Volume 26, pp. 169-193. See also Paul L. Joskow and Nancy L. Rose, "The Effects of Economic Regulation," in HANDBOOK OF INDUSTRIAL ORGANIZATION, Chapter 25, R. Schmalensee and R.D. Willig eds., Amsterdam: North-Holland, 1989, Volume 2, pp. 1477-1482.

[107] See the related discussion in Section 2.3.6.

this issue in the search for the optimal design of a PBR plan. This is evident in the continuing modifications that the AUC and the OEB have made to the treatment of supplemental capital in successive-generation PBR regimes.[108] Whereas it may be premature to declare victory in the search for the optimal PBR design, the industry may be somewhat closer to discerning the broad outlines of an optimal design insofar as capital is concerned and it has the following properties.

- The PBR plan should include as much capital as feasible under the price (revenue) cap subject to the guidelines provided by the PBR principles. When the "carve out" for supplemental capital within the PBR regime becomes unduly large, the merits of adopting PBR may be called into question.
- The quantum of supplemental capital is directly related to the regulator's willingness to recognize the negative trends in productivity growth and duly reflect these trends in the X factor for the PBR plan.[109]
- A key issue for regulators concerns the partition of supplemental capital into two disjoint categories: (i) supplemental capital for which it is efficient for the regulated company to bear the risk; and (ii) supplemental capital for which it is not efficient for the regulated company to bear the risk.
- The PBR plan should minimize the frequency with which the PBR plan is "reopened" to address matters of revenue adequacy while ensuring that the regulated companies do not bear excessive risk.
- Whereas past capital expenditures may have limited informational value in forecasting future capital requirements,[110] past expenditures may nonetheless provide the regulator with a useful validation check on such forecasts.

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108 Recall that supplemental capital refers specifically to the deficiency between capital requirements and the level of capital that is funded under the "$I - X$" PBR plan.

109 The debate over negative productivity growth is concerned less with whether recent trends exhibit negative growth and more with whether this negative trend is transitory. See notes 38 and 39 *supra*. A possible solution is to allow for updating of the X factor over the course of the PBR term.

110 Future capital requirement must take into account (i) the digitalization of the electricity sector (i.e., smart grid); (ii) increased competition and interconnection requirements; (iii) enhanced security,

3. REGULATORY COMMITMENT

The conclusion that price (revenue) cap regulation is superior to COSR (in the sense that it provides more high-powered incentives for efficiency) must be qualified accordingly. Specifically, price (revenue) cap regulation closely approximates the incentive structure of a competitive market when the regulator's commitment to the basic tenets of the PBR plan is a credible one.[111] This means that the regulated firm must have confidence that changes in the level of the price (revenue) cap, as determined by the *X* factor, are independent of its own performance. In other words, the risk of expropriation by the regulator is minimal.

As discussed above, the *X* factor in a price (revenue) cap plan determines the maximum rate at which the inflation-adjusted prices (revenues) of the firm's regulated services can increase, on average, each year until the price cap plan is reviewed. For example, if the rate of inflation is 4.5% and the *X* factor is 2%, the formula would permit the regulated firm to raise prices (revenues) on average a maximum of 2.5% (4.5% – 2%) per year. When changes in the *X* factor are conditional on the regulated firm's own performance, the regulatory regime is said to incorporate a "ratchet effect" and the firm's incentives for superior performance are adversely affected as a result.[112]

To illustrate the incentive problem associated with a "ratchet effect," suppose the *X* factor is initially set at 2% and the regulated firm works diligently to discover opportunities to innovate and

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including cybersecurity; (iv) electric automobiles and charging stations and (v) increased use of renewables. The widespread implications of increased reliance on renewables for traditional utilities are discussed in "Renewable Energy: A World Turned Upside Down," *The Economist*, February 25, 2017. http://www.economist.com/news/briefing/21717365-wind-and-solar-energy-are-disrupting-century-old-model-providing-electricity-what-will

[111] See David E. M. Sappington and Dennis L. Weisman, DESIGNING INCENTIVE REGULATION FOR THE TELECOMMUNICATIONS INDUSTRY, Cambridge MA.: MIT Press and Washington D.C.: AEI Press, 1996, Chapter 7; and Jean-Jacques Laffont and Jean Tirole, COMPETITION IN TELECOMMUNICATIONS, Cambridge MA.: MIT Press, 2000.

[112] This practice is sometimes referred to as "moving the goal posts."

improve operating efficiency. As a result of these efforts, the regulated firm is able to realize efficiency gains of 3% per year. The regulator, having observed that the firm is able to achieve efficiency gains that exceed the *X* factor, decides that the *X* factor can safely be ratcheted upward. Over time, the regulated firm learns that its greater effort to secure efficiency gains will simply be appropriated by the regulator in the form of lower rates to consumers.[113] This type of strategic behavior undermines the regulated firm's incentives to discover and implement efficiency improvements.

> Under PCR [Price Cap Regulation], the firm's earnings may be "higher than normal" because (i) the initial prices are set too high; (ii) the X-factor in the price cap plan is set too low; or (iii) the regulated firm exercised its superior business acumen and managerial prowess to outperform the industry-wide X-factor. The key point, however, is that higher than normal earnings no longer (necessarily) imply rates that are not "just and reasonable." These higher than normal earnings may simply reflect the stronger incentives for efficient performance under price cap *vis a vis* earnings regulation. Should this be the case, these additional earnings would not exist but for the regulator's commitment to allow the regulated firm to be the residual claimant for its realized efficiency gains. In other words, the ability on the part of the regulator to appropriate these earnings may exist only because the firm believed the regulator would not take unfair advantage of this opportunity. It follows that because PCR breaks the link between prices and costs, it must also break the link between higher than normal profits and excessive rates, which is essentially the *Hope* standard (footnotes omitted).[114]

[113] At least in the United States, the change from COSR to PBR has not been accompanied by a corresponding change in the underlying case law. Regulators in the U.S. have considerable discretion to adopt policies, such as entry accommodation, that reduce the regulated firm's earnings provided that they do not impede the regulated firm's ability to raise capital and remain a financially viable enterprise. See Dennis L. Weisman, "Is There 'Hope' for Price Cap Regulation?," *Information Economics and Policy*, Volume 14(3), 2002, pp. 349-370; and Ronald R. Braeutigam and John C. Panzar, "Effects of the Change from Rate-of-Return to Price-Cap Regulation," *The American Economic Review*, Papers and Proceedings, Volume 83(2), May 1993, pp.191-198. To understand the nature of the problem, recognize that the regulator can effectively breach the price cap commitment, not by directly lowering the price cap but by adopting liberal competitive entry policies that render it unprofitable for the regulated company to sustain a price at the level of the price cap. To draw an analogy, this is akin to a basketball game in which the regulator commits not to raise the height of the basket but retains the discretion to lower the floor.

[114] Dennis L. Weisman, "Is There 'Hope' for Price Cap Regulation?," *Information Economics and Policy*, Volume 14(3), 2002, pp. 63-64.

Under pure price (revenue) cap regulation *vis-à-vis* price (revenue) cap regulation with earnings sharing, the regulatory authority agrees not to adjust the prices (revenues) of the regulated firm's services on the basis of its actual earnings or costs for the duration of the PBR regime. To do so, of course, would represent a form of earnings regulation and re-establish the very link between allowed earnings and costs that price (revenue) cap regulation seeks to break. A strong regulatory commitment is therefore critical to the superior performance of the PBR regime.

It follows that if the firm is uncertain as to whether regulatory commitments will be honored, there may be little practical difference between PBR and COSR. In this manner, a weak regulatory commitment undermines the superior incentive properties of PBR. Under such conditions, the regulated firm would not operate as if it faced competitive market conditions and PBR Principle 1 is not satisfied. The problems associated with an uncertain regulatory commitment are well documented in the literature.

> …Can the regulator credibly pre-commit to a system of price cap regulation? Stated differently, can today's regulatory commission bind its successor? A regulatory agency is likely to be subjected to considerable political pressure to change the price cap or price cap formula over time. If a firm regulated by price caps begins to earn large profits, consumers will no doubt petition the regulator to lower the price in the core market.[115]
>
> This issue of recontracting and the efficiency distortions resulting therefrom is arguably one of the more serious problems with PC [Price Cap] regulation in practice. A key premise underlying PC regulation is that increased profits for the firm will be viewed by regulators and their constituency as something other than failure of regulation itself. If this premise is false, then regulators will be under constant political pressure to recontract when the firm reports higher profits. In equilibrium, the firm learns that this is how the game is played and the efficiency gains from PC regulation in theory may fail to materialize in practice.[116]

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[115] Ronald Braeutigam and John C. Panzar, "Diversification Incentives Under 'Price-Based' and 'Cost-Based' Regulation," *Rand Journal of Economics*, Volume 20(3), 1989, p. 320.

[116] Dennis L. Weisman, "Superior Regulatory Regimes in Theory and Practice," *Journal of Regulatory Economics*, Volume 5(4) 1993, pp. 364-365.

4. BENCHMARKING

A seminal theme in this discussion is the basic concept that economic regulation should seek to emulate competitive market outcomes. This concept is significantly easier to state in the abstract than it is to apply in practice. This observation underscores the role of benchmarking in PBR regimes.[117]

4.1 The Theory

Suppose that there is a utility A that is subject to economic regulation. In addition, there is a utility B that is a clone of utility A in terms of exogenous operating characteristics (i.e., size of service territory, topography, climate, number of customers, etc.). The only differentiating characteristic between the two utilities is their respective investments in (unobserved) cost-reducing effort (e). What this means is that the regulator can observe the accounting costs of the two utilities, but s/he cannot observe the amount of effort invested to obtain these costs. How might the regulator go about regulating utility A if the objective is to emulate a competitive market outcome and induce efficient investment in cost-reducing effort?

The regulator would go about creating a tournament of sorts so that utility A would act as if it faced competition from utility B even though it does not. We might refer to this tournament as pseudo competition. Let P^A and P^B denote the respective prices that utility A and utility B are permitted to charge for their services. Similarly, let $c^A(e)$ and $c^B(e)$ denote, respectively, the constant unit costs for utility A and utility B. As is standard in the literature, investment in cost-reducing effort (e) is assumed to reduce unit costs at a decreasing rate. The cost to the utility for

[117] See Andrei Schleifer, "A Theory of Yardstick Competition," *Rand Journal of Economics*, Volume 16(3), 1985, pp. 319-327.

cost-reducing effort is assumed to be increasing in effort at an increasing rate. There are assumed to be no fixed costs of production in this simplified analysis.

What pricing rule should the regulator adopt for utility A (respectively utility B)? The regulator would set $P^A = c^B(e)$ and $P^B = c^A(e)$. In other words, the price for utility A would be equal to the unit cost of utility B and *vice versa*. This pricing rule is efficient and consistent with the regulator's objective to emulate competition (in the absence of competition). To see this, let Q^A denote the number of units of output that utility A sells. Utility A's accounting profits may then be expressed by $\Pi^A = Q^A \times (P^A - c^A(e)) = Q^A \times (c^B(e) - c^A(e))$. Utility A's accounting profits are therefore equal to the product of its output and the price-cost margin on each unit of output that it sells.

There are three key observations about utility A's profit. First, utility A generates positive profits only if it is more efficient than its pseudo rival, utility B, or $c^A(e) < c^B(e)$. Otherwise, utility A realizes a loss. As a result, each utility "competes" to have the lowest cost. Second, utility A would have ideal (first-best) incentives to invest in cost reducing effort under this pricing rule. Specifically, utility A will invest in cost-reducing effort up to the point where the marginal benefit of cost-reducing effort is equal to it marginal cost. Because $P^A = c^B(e)$, utility A will choose the efficient level of cost-reducing effort since increased effort does not reduce the price that it is permitted to charge for its services (i.e., the utility is the residual claimant for its efficiency gains). The utility is not penalized for reducing its costs because its price is invariant to its actual costs. This pricing rule avoids the "ratchet effect" that is responsible for the low-powered incentives of COSR.

4.2 From Theory to Practice

The theory outlined in the previous subsection is an elegant solution to a complex problem, but the steps from theory to practice are lined with myriad obstacles. First, in the real-world there is no perfect clone for the utility. Second, utilities are heterogeneous rather than homogenous. Consequently, it can be very difficult if not impossible to reach a consensus as to the appropriate peer group of utilities to facilitate a meaningful comparison. Third, in theory, any exogenous differences between the utilities must be duly accounted for in order to adjust the compensation scheme accordingly. Failure to do so can result in either over-compensation or under-compensation for the utility. Properly accounting for these exogenous differences necessitates complex statistical analysis that can contribute to highly contentious regulatory proceedings.

There are two prospective applications of benchmarking in the context of the rate adjustment formula discussed in Section 2.5: the productivity offset (*X*) and the stretch factor (*S*). An important consideration concerns whether the benchmarking analysis applies to levels or changes in levels. This distinction is important because heterogeneity across firms is likely to be a more serious problem when benchmarking levels than when benchmarking changes in levels.

For example, some utilities are vertically-integrated, while others participate only in distribution. Scope economies (efficiencies attributable to multi-element production) may result in lower cost levels for vertically-integrated utilities in comparison with utilities engaged in distribution only. Nonetheless, the technological progress of these firms (the rate at which they can reduce their costs over time) may be quite similar. What this suggests is that a peer group of firms that is inappropriate for benchmarking levels may be entirely appropriate for benchmarking changes in levels.

4.2.1 The Productivity Offset (X)

Recall that productivity is defined as the ratio of outputs to inputs, whereas productivity growth is defined as the percentage change in outputs less the percentage change in inputs. In North American PBR plans, it is common practice to inform the development of an *X* factor on the basis of productivity growth for a representative peer group of firms that constitutes the industry. In the case where the heterogeneity across firms largely vanishes when the metric is technological progress (i.e., productivity growth as opposed to productivity), it may be advisable to employ the largest possible sample of firms. Conversely, if there is reason to believe that heterogeneity across firms persists even when the metric is technological progress, it may be advisable to restrict the sample to promote a greater degree of homogeneity.

In this latter case, it is important that (i) great care be taken in limiting the sample so that all feasible sources of heterogeneity are accounted for in the analysis; and (ii) the sample restriction does not focus too narrowly on a subset of exogenous operating characteristics to the exclusion of others. For example, suppose mean average temperature is an exogenous characteristic over which firms reasonably differ. It would not be appropriate to draw a sample based solely on this metric if there is reason to believe that the number of customers and topography are also important exogenous factors that explain differences in technological progress across firms. Hence, when it is not possible to control for all important exogenous factors that explain differences across firms there can be no reasonable guarantee that truncating the sample of firms to reflect a proper subset of exogenous characteristics produces a more representative peer group.[118]

4.2.2 The Stretch Factor (S)

[118] There is also a potential tradeoff regarding sample size. Specifically, a smaller, more homogeneous sample is likely to be less precise (e.g., greater standard deviation) and more sensitive to the results of outlier firms.

Unlike the *X* factor, there is no consensus in regulatory practice that the stretch factor (*S*) in a PBR plan can be developed in a scientifically rigorous manner on the basis of benchmarking across firms. Recall from the discussion in subsection 2.5 that *S* is designed to account for the increase in productivity growth associated with the change from COSR to PBR (i.e., from low-powered to high-powered incentives).[119] The predominant view among regulators is that the value of *S* is a judgement call. The AUC's views on this issue are seemingly representative.

> [T]he determination of the size of a stretch factor is, to a large degree, based on a regulator's judgement and regulatory precedent and does not have a "definitive analytical source" like the TFP study represents.[120, 121]

In its first-generation PBR regime, the AUC set the stretch factor at 0.2 percent for all the utilities under its jurisdiction.[122] This approach differs from that of the OEB in two important respects. First, the OEB chooses a range of stretch factors for 5 different cohorts of firms, {0.0. 0.15, 0.30, 0.45, 0.60}, that vary across companies based on their relative efficiency.[123] Second,

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119 As the AUC observed:

> The purpose of a stretch factor is to share between the companies and customers the immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime.

Alberta Utilities Commission, Decision 2012-237, September 12, 2012, paragraph 479. In addition, formal benchmarking analysis was not used to develop stretch factors for telecommunications firms in North America.

120 *Id.,* paragraph 497.

121 The BC Commission stated that "We agree with Fortis that a stretch factor is judgment based and will use our judgment to determine one that is appropriate" (p. 40). The commission subsequently ordered a benchmarking study be conducted to inform its judgement (p. 82). British Columbia Utilities Commission, In the Matter of FortisBC Energy Inc., Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018, Decision, September 15, 2014.

122 Alberta Utilities Commission, Decision 2012-237, September 12, 2012, paragraph 499.

123 Ontario Energy Board, EB-2010-0379, Report of the Board, Performance Measurement for Electricity Distributors: A Scorecard Approach December 4, 2013. https://www.oeb.ca/oeb/_Documents/EB-2010-0379/Report_of_the_Board_Scorecard_20140305.pdf In its third-generation PBR regime, the OEB had previously partitioned electricity distributors into three different cohorts with a range of stretch factors of {0.2, 0.4, 0.6}.

the OEB relied upon statistical benchmarking to determine the relative efficiency of each of the utilities. It is important to recall that there are 70+ regulated firms under the OEB's jurisdiction that vary significantly in terms of scale of operations.

The problem in selecting a stretch factor based on the regulated firm's relative efficiency is that it involves comparing levels of efficiency (e.g., productivity) rather than changes in efficiency (e.g., productivity growth) and thereby introduces the familiar heterogeneity problem discussed above. Specifically, is it reasonable to believe that all of the important exogenous factors that explain the differences in relative efficiency across regulated firms have been properly accounted for in the analysis?

Without addressing the relative merits of determining the stretch factor based on informed judgement *vis-à-vis* formal statistical benchmarking,[124] there is a sound policy rationale for allowing the stretch factor to (potentially) vary across firms. Consider, for example, two utilities, utility 1 and utility 2. Under COSR regulation, utility 1 behaves as if it faces high-powered incentives by implementing diligent cost-control measures and undertaking significant investment in innovation. In contrast, under COSR regulation, utility 2 behaves as if it faces the low-powered incentives that it does by implementing only modest cost control measures and undertaking only limited investment in innovation relative to utility 1. As a result, utility 1 enters PBR as a relatively efficient firm, whereas utility 2 enters PBR as relatively inefficient firm.

Suppose now that the regulator adopts the same stretch factor for both utilities. Utility 1 will have to work considerably harder than utility 2 to realize the incremental productivity gains

[124] Nonetheless, with specific reference to the statistical benchmarking approach to setting the stretch factor, the AUC stated that "the Commission does not wish to engage in this type of analysis for the purposes of PBR in Alberta because of the practical and theoretical problems associated with comparing efficiency levels among companies." Alberta Utilities Commission, Decision 2012-237, September 12, 2012, paragraph 481.

reflected in the common stretch factor because it will have already picked the “low-hanging fruit.” Conversely, utility 2 will not have to work as hard as utility 1 because the easy to pick “low-hanging fruit” has yet to be picked. Hence, in a very real sense, utility 1 has been penalized for its diligence in cost-control under COSR, while utility 2 benefits from its lack of diligence in cost-control under COSR. From utility 1’s perspective, “no good deed goes unpunished.” What this suggests is that, at least in theory, there is a credible argument for recognizing the possibility that stretch factors differ across firms. Administrative complexities, inclusive of the myriad issues associated with Principle 3, may well explain why this approach is not standard regulatory practice in North America.

5. PBR and Crown Corporations

As Observation 1 makes clear, a key tenet of PBR is that the regulated company bears greater risk in exchange for the prospect of greater reward. In the case of private enterprise, the reward metric is earnings or financial returns. Public enterprises or crown corporations are typically not profit-maximizing entities. Therefore, an important question concerns whether PBR works (or can be made to work) in the case of crown corporations?

In the case of a crown corporation, the government may have a strong interest in the “earnings” that flow from the company to the government, but profit-maximization is not its sole focus given that the higher rates that may accompany higher profits are not necessarily aligned with the interests of the citizenry. A similar issue confronted Edmonton Distribution and Transmission Incorporated (EDTI), wholly owned by EPCOR Utilities Inc. (EUI), which in turn is wholly owned by the City of Edmonton. Notably, EDTI is currently under its second-generation PBR regime administered by the AUC.[125]

It is noteworthy that postal systems throughout the world are government owned. Nonetheless, PBR has been successfully applied to postal systems to strengthen incentives for superior performance. The following quotations are helpful in framing the relevant issues.

> Rate ceilings are not merely a tool to deliver greater management flexibility. They are a powerful incentive for achieving what is largely lacking at the Postal Service today: the alignment of the interests of postal managers and employees with the interests of ratepayers. Specifically, rate ceilings allow prices to be adjusted upward within limits established by a regulator based on an "escalator" that incorporates factors for both inflation and productivity.[126]
>
> It should be noted that some doubt exists as to whether a public-sector institution (without, for example, employee stock options) can successfully use these tools. Leading experts, however, believe that a combination of *negative* incentives (such as holding managers accountable for performance) and *positive* incentives (such as performance bonuses) can take full advantage of this innovative mechanism to the ultimate benefit of ratepayers.[127]

With respect to the application of PBR to crown corporations, there are two seminal questions. First, can the PBR regime be structured so that the maximum permissible rate changes emulate a competitive market standard as per PBR Principle 1? Second, is it possible to provide management in a crown corporation with the same high-powered incentives for efficiency and innovation as managers in a private enterprise? As the discussion below makes clear both questions can be answered in the affirmative.

5.1. Competitive Rate Changes in PBR Regimes

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[125] EPCOR Water Services Inc. (EWSI), which serves the City of Edmonton, is also regulated under a PBR framework that is approved by the City of Edmonton.

[126] EMBRACING THE FUTURE – MAKING THE TOUGH CHOICES TO PRESERVE UNIVERSAL MAIL SERVICE, Report of the President's Commission on the United States Postal Service, Washington D.C., July 31, 2003, p. 59.

[127] *Id.,* footnote omitted.

Provided that the *X* factor is developed in accordance with sound economic principles, regulators can be assured that the maximum-permissible rate changes are consistent with the competitive market standard that is called for in PBR Principle 1. Hence, the fact that the PBR regime is being applied to a crown corporation *vis-à-vis* a profit-maximizing enterprise does not present any insurmountable difficulties insofar as permissible rate changes that emulate a competitive market standard are concerned.

5.2. High-Powered Incentives for Efficiency and Innovation

The fact that profit-maximization is not the sole focus of the public enterprise can potentially weaken incentives for efficiency and innovation.[128] This observation poses a prospective problem for the application of PBR to crown corporations. Specifically, absent strong incentives for efficiency and innovation under the PBR regime managers may not be expected to invest optimally in efficiency and innovation. As a result, the rates set in the course of the rebasing process may be "too high."

This problem can be overcome, however, if the managers in a crown corporation are incented to behave as if profit-maximization were the objective of the corporation even though it is not. To see this, suppose that the government requires the corporation to surrender the entirety of its earnings on an annual basis. Under these conditions, the PBR regime would have no stronger incentives for efficiency than the textbook model of COSR. The gains from additional managerial effort are not retained by management, but simply increase the earnings that are surrendered to the government on a dollar-for-dollar basis. As a result, management sees no benefit from increasing efficiency and innovation—the benefits from additional effort are non-existent while effort and

[128] This observation notwithstanding, there are notable examples of publicly owned utilities that are incredibly innovative and efficient. See Mason Willrich, MODERNIZING AMERICA'S ELECTRICITY INFRASTRUCTURE, Cambridge MA: The MIT Press, 2017, chapter 5 and pp. 211-212.

innovation are privately costly (less effort is preferred to more). This can be thought of in terms of the government levying a 100% marginal tax rate on the earnings of the crown corporation.

Now suppose that the government no longer requires the crown corporation to surrender the entirety of its earnings. As an alternative, the government permits management to retain the difference between its current earnings and a fixed level of earnings that may be indexed over time.[129] Management would recognize that under this new compensation scheme it is the residual claimant for its efficiency gains. The amount of earnings surrendered to the government is invariant to management's behavior (just as the price/revenue cap is invariant to the firm's behavior).[130] The marginal tax rate on earnings under this compensation scheme is now 0% rather than 100%.[131] Management now has ideal incentives to improve efficiency and innovate since it retains the entirety of any surplus (net of the fixed earnings payment to the government).

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[129] A case in point is Jacksonville Electric Authority. In 2015, this publicly owned utility had 450,000 electricity customers and contributed \$114 million to the city of Jacksonville. This contribution is scheduled to escalate at 1% per year. See Mason Willrich, MODERNIZING AMERICA'S ELECTRICITY INFRASTRUCTURE, Cambridge MA: The MIT Press, 2017, pp. 51-52.

[130] Heuristically, this incentive structure can be conceived of in terms of the government "selling" the company to management in exchange for a guaranteed stream of earnings over time. An example from the Chinese agricultural sector is instructive. Under the earlier commune system, peasants were organized into production teams. Each team member was assigned work points that attempted to measure how many hours and how effectively the member had worked. The work points were not directly related to work effort because this could not be directly observed. In addition, there was a tendency to spread the commune's earnings across the commune members in a manner that resulted in larger families receiving more earnings. China subsequently changed to a responsibility system. Each peasant family was given a long-term lease on a plot of land. The family was required to deliver a certain quota of produce to the government and was allowed to keep any surplus over and above the government quota. As a result of the adoption of the responsibility system, which provided a direct link between effort and reward, productivity soared in the agricultural system. This occurred because the family was now the residual claimant for its efforts in producing agricultural output in excess of the government quota. See John McMillan, GAMES, STRATEGIES AND MANAGERS, New York: Oxford University Press, 1992, pp. 96-98. It is estimated that 78 percent of the increase in agricultural productivity in China between 1978 and 1984 can be attributed to the incentive effects of the new responsibility system. John McMillan, John Whalley and Lijing Zhu, "The Impact of China's Economic Reforms on Agricultural Productivity Growth, *Journal of Political Economy*, Volume 97(4), August 1989, pp. 781-807.

[131] Alternatively, suppose that the government agrees to allow management to retain 50% of the difference between its actual earnings and the indexed level of earnings. This management compensation scheme

It is noteworthy that EUI in Alberta is subject to a similar compensation structure. Specifically, the EUI's shareholder has an expectation of annual dividend increases that are independent of EUI's actual performance. Management effectively retains any surplus that remains after the payment of the dividend.[132] In other words, management is the residual claimant for any gains from efficiency and innovation that remain after the dividend is paid. This compensation structure provides management with a profit motive for superior performance even though the corporation itself is not a profit-maximizing enterprise.

In similar fashion to the regulatory commitment problem discussed in Section 3, management must perceive a strong commitment on the part of the government to adhere the terms and conditions of the management compensation scheme. If the government's commitment is perceived to be weak, management may have little or no incentive to invest in the cost-reducing innovation necessary to realize positive returns.

By way of conclusion, PBR can be effectively applied to a crown corporation. In order to realize the myriad benefits expected of PBR it will be necessary for the government to adopt a management compensation structure with incentive properties similar to those discussed above. Absent such an incentive-based compensation structure for management, the crown corporation

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would have efficiency properties similar to earnings sharing mechanisms discussed in section 2.6. The 50% marginal tax rate would tend to weaken incentives for efficiency but is nonetheless superior to the 100% marginal tax rate associated with a dollar-for-dollar pass-through. It should be noted, however, that the crown corporation could potentially be subject to two different ESMs, the first imposed by the regulator and the second imposed by the government. The strength of management's incentive to innovate will depend on the composite marginal tax rate associated with both ESMs. Suppose, for example, that the regulator implements an ESM with a marginal tax rate of t and the government further taxes earnings at a marginal tax rate of t. The composite marginal tax rate facing the crown corporation is given by $t^{comp} = t + t \times (1 - t) = 2t - t^2$. Hence, if $t = 50\%$, $t^{comp} = 75\%$. This means that the crown corporation retains only 25 cents or $(1 - t^{comp})$ of each additional dollar in cost savings, which equates to relatively low-powered incentives. This example abstracts from government-levied corporate taxes.

132 The EDTI managers further indicated that the city of Edmonton is not involved in the managerial oversight of EDTI. As a result, management has freedom to innovate in the pursuit of efficiency gains.

may have incentives for efficiency and innovation that are no stronger than those under textbook COSR regardless of the PBR regime adopted by the BC Commission. Should this be the case, the expected net benefits from adopting PBR are *de minimis*.

6. SUMMARY AND CONCLUSIONS

This report examines the fundamental properties of PBR, including design and implementation issues. The prospective benefits of adopting PBR are compared with traditional COSR. It is instructive to conceive of PBR and COSR as lying along a continuum of regulatory regimes wherein the differentiating characteristic is the strength of the incentives for efficient performance (i.e., high-powered or low-powered incentives). Depending on the design of the PBR regime, including the term of the regime, the strength of the regulatory commitment and whether it includes earnings sharing, the distance between PBR and COSR on this continuum may be great or small. In other words, a poorly designed PBR regime may not represent a significant improvement over COSR.

The experience with incentive regulation in the telecommunications industry closely tracks the predictions of the theoretical regulatory economics literature in terms of expected efficiency gains, innovation and the benefits to key stakeholder groups. The experience with PBR in the energy sector, while certainly demonstrating promise, is not as universally positive. As explained in this report, there are numerous possible explanations for these differences, including conservation objectives, differential rates of productivity growth, and the myriad complexities associated with the need for supplemental capital. In addition, it is possible that at least some of the benefits attributed to incentive regulation in the telecommunications industry were actually due to the emergence of rivalrous competition in that sector.

Policymakers should recognize that the expected gains from adopting PBR may be subject to greater uncertainty in the case of crown corporations. In many respects, these public enterprises are *de facto* subject to two different regulatory authorities—the regulatory commission of jurisdiction and its government owners. Nonetheless, PBR plans have been successfully applied to public enterprises.

Finally, if the PBR regime is not developed in accordance with sound economic principles, or there is not a strong commitment to the fundamental tenets of PBR on the part of either the regulator or the government, the significant resources required to design and implement a PBR regime would be difficult to justify. The adoption of PBR may simply fail the cost-benefit test under these conditions.

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Arkansas Public Service Commission

British Columbia Utilities Commission

California Public Utilities Commission

Canadian Radio-Television and Telecommunications Commission

Colorado Public Utilities Commission

Federal Communications Commission

Florida Public Service Commission

Kansas Corporation Commission

Kansas State Legislature (Commerce Committee)

Massachusetts Department of Public Utilities

Missouri Public Service Commission

Texas Public Utilities Commission

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"A General Theory of Point-to-Point Long Distance Demand." Bell Communications Research Business Research Conference, Durango, Colorado, October 1984.

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1991	University of Florida Research Fellowship
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Appendix GG

Assessing the Treatment of Capital Expenditures in PBR Plans

ASSESSING THE TREATMENT OF CAPITAL EXPENDITURES IN PERFORMANCE-BASED REGULATION PLANS

by

David E. M. Sappington and Dennis L. Weisman*

September 1, 2015

EXECUTIVE SUMMARY

This report was commissioned by EPCOR to identify and objectively evaluate the merits of potential alternative approaches to the treatment of capital expenditures (CAPEX) in performance-based regulation (PBR) regimes. This pro-active approach to the analysis may help to resolve critical issues regarding the treatment of capital in PBR regimes outside the adversarial environment of a formal regulatory proceeding.

The report analyzes both earnings-based and price-based PBR plans. A total of eleven difference approaches are evaluated (three earnings-based plans and eight price-based plans). The advantages and disadvantages of each plan are assessed, and references are provided to the relevant economics literature to facilitate further analysis. In addition, where appropriate, the PBR principles set forth by the Alberta Utilities Commission (AUC) in its 2012 PBR proceeding are linked to the various advantages and disadvantages of each approach.

Our preliminary recommendation regarding appropriate approaches reflects four main criteria. First, the AUC is unlikely to adopt any approach containing elements of traditional rate of return regulation. Second, the AUC places a large premium on simplicity, transparency and reducing the regulatory burden for all parties. Third, the preferred approaches should address the issue of capital sufficiency in a comprehensive and principled manner. Fourth, the preferred approaches must provide strong incentives for efficiency, comparable to incentives that arise in competitive markets.

Our preliminary recommendation is that the AUC adopt a pure price cap approach that incorporates an economically principled mechanism that can address all three of the capital tracker categories that EPCOR identified in the 2013 Capital Tracker proceeding. Three of the eleven approaches evaluated in the report (those analyzed in Sections III.C, III.E, and III.F) appear to satisfy these requirements. We believe that each of these approaches satisfactorily addresses both company and Commission concerns while preserving to the extent possible the desirable efficiency incentives of competitive markets.

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I. INTRODUCTION.

A. Background and Purpose of this Report.

In 2012, Application No. 1606029, Proceeding ID No. 566, the Alberta Utilities Commission ("AUC") launched its first industry-wide performance-based regulation ("PBR") initiative for the electric power and natural gas industries.[1] The initiative reflected in part the largely favorable experience with PBR in the telecommunications industry.[2,3] However, it became clear early on in the process that important differences between the energy and telecommunications sectors would require a form of PBR in the Alberta energy sector that differed from common forms of PBR in the telecommunications sector.[4] In particular, the relatively simple $I - X$ price cap plans often implemented in the telecommunications sector were deemed to be inappropriate for Alberta's utilities.[5]

Alberta's utilities believed it was important to have the opportunity to formally reassess their anticipated capital requirements and adjust allowed prices accordingly during the course of the PBR regime. Such a "re-opening" mechanism typically is not present in PBR plans in the telecommunications industry. This may be the case in part because the ongoing decline in the cost of computing enables telecommunications firms to count on increasing profit margins over the course of a PBR regime.[6] Corresponding systematic cost-reducing forces are not present to the same degree in the electric power and natural gas industries. Consequently, absent an opportunity

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1 In AUC 2009-035, the Commission issued its order for the PBR plan for ENMAX. Notably, this PBR plan was initiated at the request of ENMAX rather than the AUC. The AUC's March 25, 2010 Rate Regulation Initiative Roundtable recognized that traditional rate of return regulation was no longer the appropriate regulatory regime for the Alberta utilities, and explored alternative regulatory regimes with superior incentive properties.

2 See Abel (2000) and Lowry and Kaufman (2002), for example.

3 Two key members of the AUC, Chairman Willie Grieve and Vice-Chair Mark Kolesar, joined the Commission after long careers in the Canadian telecommunications industry. Both served on the AUC panel for the PBR initiative.

4 EPCOR (June 13, 2012, ¶¶ 121-127).

5 The $I - X$ index limits annual price changes for the regulated firm to an economy-wide inflation measure (I), less an offset (X). To illustrate, if I is 3% and X is 2%, the regulated firm is permitted to increase its prices by 1% (= 3% $-$ 2%) annually, on average. X measures the extent to which productivity in the regulated industry is expected to increase more rapidly and industry input prices are expected to increase less rapidly than in the economy as a whole. See Bernstein and Sappington (1999).

6 See Jorgenson (2001), for example.

to revisit the terms of a lengthy PBR regime, regulated firms may experience unduly low returns and face substantial earnings uncertainty.

These concerns may help to explain why, even though PBR was adopted relatively rapidly in the telecommunications sector (often at the initiative of the companies themselves), the implementation of PBR has experienced fits and starts in the electric power and natural gas industries.[7] The differential patterns of technological advance in the telecommunications and energy sectors likely has led the companies in the former sector to embrace the opportunities for enhanced earnings presented by price cap regulation and the companies in the latter sector to prefer the earnings stability afforded by traditional rate of return regulation.

By the end of the PBR hearings in the late spring of 2012, the AUC concluded that: (i) capital expenditures ("CAPEX") likely required some special treatment in the design of PBR plans; and (ii) it would be appropriate to consider the unique circumstances of each company when determining the treatment of its CAPEX under PBR.[8] In particular, the AUC recognized the need for a mechanism that would permit reconsideration of the terms of the PBR plan as the need for unforeseen capital expenditures arose. The Commission's focus then turned to designing a PBR plan that addressed the concerns of the companies regarding capital requirements over the course of the PBR regime while preserving to the greatest extent possible the incentives for efficiency that prevail in competitive markets.[9]

In its 2012 PBR decision, the AUC adopted a capital tracker approach (and associated *K* factor adjustment) as the mechanism through which the companies would be allowed to re-open the PBR plan in order to address unforeseen capital expenditures. The AUC specified three conditions that a capital project must satisfy in order to qualify as a capital tracker, and thereby receive explicit consideration by the Commission:[10]

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[7] This issue was discussed at length at the PBR hearings and summarized in EPCOR's Final Argument in that proceeding. See EPCOR (June 13, 2012, ¶¶ 121-127).

[8] Alberta Utilities Commission (AUC), Rate Regulation Initiative, Application No. 1606029, Proceeding ID No. 566, Proceedings, Volume 10, April 27, 2012, pp. 1962-3.

[9] Makholm et al. (2012) survey PBR plans in the U.S. and Canada and discuss how regulators might incorporate "trackers" into PBR plans to address cost items not traditionally covered by PBR plans. (Dr. Jeffrey Makholm was retained by the AUC to provide economic testimony in the AUC's 2012 PBR proceeding.)

[10] AUC Decision 2012-237, ¶ 592.

(1) The project must be outside of the normal course of the company's ongoing operations.[11]

(2) Ordinarily the project must be for replacement of existing capital assets, or undertaking the project must be required by an external party.

(3) The project must have a material effect on the company's finances.

The total dollar amount of all capital projects approved by the Commission as capital trackers are included as a K factor in the price cap formula and operates in a manner similar to the exogenous factor or Z factor common to most price cap plans.[12] The Commission adopted the capital tracker approach and rejected other approaches with similar objectives. The Commission did so because it believed this approach would limit the extent to which the strong incentives of competitive markets would be diluted. Specifically, the Commission rejected other approaches suggested by the companies that the Commission believed would reintroduce elements of traditional rate of return regulation and its poor incentive properties.[13]

In the 2013 Capital Tracker proceeding, EPCOR identified three categories of capital trackers. These categories are reviewed here to provide context for the ensuing analysis. Category 1 capital trackers consist of life cycle replacement projects and/or projects that EPCOR is obligated to undertake at the request of a third party, where, in both cases, the $I - X$ component of the PBR formula does not provide any funding for CAPEX. Category 3 trackers are Category 1 type trackers that were completed and added to the rate base in 2012. Category 2 trackers consist of trackers that are intended to permit EPCOR to recover project-by-project capital funding shortfalls that it would otherwise incur when the $I - X$ component of the PBR formula includes funding for CAPEX. An outstanding issue of demonstrated interest to the Commission is whether there is an efficiency rationale for treating Category 1 and Category 3 trackers differently from Category 2 trackers.

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11 In AUC Decision 2013-435, the Commission interpreted the phrase "outside of the normal course of the company's ongoing operations" somewhat more broadly. Specifically, the Commission allowed for capital trackers in the case of extraordinary projects as well as project-specific expenditures incurred in the course of ongoing operations that were deemed to be funded inadequately under the $I - X$. See AUC Decision 2013-435, § 3.1.3.

12 In particular, the regulated company is permitted to raise its prices annually at the rate of $I - X + K$, where I is the prevailing rate of inflation in the economy, X is a productivity factor, and K reflects costs associated with the types of unanticipated investment projects described above.

13 AUC Decision 2012-237, § 7.3. These poor incentive properties are discussed in Section II.A below.

B. AUC PBR Principles.

The Commission determined that a well-designed PBR plan should reflect the following principles:

The AUC's PBR Principles

Principle 1. A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.

Principle 2. A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.

Principle 3. A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.

Principle 4. A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.

Principle 5. Customers and the regulated companies should share the benefits of a PBR plan.

The present report was commissioned by EPCOR to identify and objectively evaluate the merits of potential alternative approaches to the treatment of capital in PBR regimes. This pro-active approach to the analysis may help to resolve critical issues regarding the treatment of capital in PBR regimes outside the adversarial environment of a formal regulatory proceeding.

C. The Purpose and the Forms of PBR.

The economics literature advises that economic regulation should seek to emulate competitive market outcomes. As Professor Alfred Kahn observes:

> the single most widely accepted rule for the governance of the regulated industries is regulate them in such a way as to produce the same results as would be produced by effective competition, if it were feasible. (Kahn, 1970, p. 17)

Similarly, Professor James Bonbright observes:

> Regulation, then, as I conceive it, is indeed a substitute for competition; and it is even a partly imitative substitute. (Bonbright, 1961, p. 107)

Once the central goal of economic regulation is identified, the best means to achieve this goal must be determined. In particular, it is important to identify the form of PBR plan that will best replicate the incentives that prevail in competitive markets. Competitive market forces constrain the prices firms can charge, limiting them to only a normal return on their investments.

Consequently, a regulator might seek to emulate competitive market outcomes either by adopting an earnings-based regulating regime (which constrains a company's earnings) or by adopting a price-based regime (which constrains the prices the company can charge for the services it supplies to customers).

Traditional rate of return regulation is an example of an earnings-based regulatory regime that seeks to instill competitive discipline by limiting the regulated firm's financial returns. Pure price cap regulation is an example of a price-based regulatory regime that seeks to instill competitive discipline by capping the prices of the regulated firm. A central question in the literature on the economics of regulation is whether earnings-based regulatory regimes, price-based regulatory regimes, or some combination of the two types of regulation are the best means to replicate the discipline of competitive markets (Joskow, 2014).

Professors Armstrong and Sappington offer the following perspective on the tradeoffs between the two types of regulatory regimes.

> Now consider price cap regulation, which typically permits revenues to diverge from realized costs for a specified period of time (e.g., four years) but does not promise specific long-term returns on investment. Although such a policy can provide substantial incentive for short-term innovation and cost reduction, it may provide limited incentive for long-term infrastructure investment. Therefore, the choice between rate of return regulation and price cap regulation will depend in part on the type of investment that is most important to secure. In settings where the top priority is to induce the regulated firm to employ its existing infrastructure more efficiently, price cap regulation may be preferable. In contrast, in settings where it is important to reverse a history of chronic underinvestment in key infrastructure, rate of return regulation may be preferable (footnotes omitted).[14]

This observation highlights a central theme in the literature on the economics of regulation, namely that a one-size-fits-all approach to the design of PBR plans is not appropriate. To the contrary, a PBR plan that is implemented for a particular company should reflect both the type of behavior the regulator wishes to encourage the company to undertake (which can vary across companies) and the unique characteristics of the regulated industry and the regulated company. As Professor Guthrie concludes from his survey of the economic literature that examines the relationship between regulation and infrastructure investment:

> The two most important lessons to be drawn from the literature surveyed here are that there is no single combination of regulatory settings that is best in all situations and

[14] Armstrong and Sappington (2006, pp. 340-41).

> that the various components of a regulatory scheme are interrelated. The most appropriate regulatory scheme for a given situation will depend on the characteristics of the firm and industry being regulated, as well as the institutional environment.[15]

D. The Outline of this Report.

This report will assess several possible approaches to the treatment of capital in PBR regimes by identifying the central advantages and disadvantages of each approach. Sections II and III of the report consider earnings-based PBR plans and price-based PBR plans, respectively. Section IV provides a brief summary and a preliminary recommendation as to the preferred approach (or approaches) to the treatment of capital in PBR regimes.

II. EARNINGS-BASED PBR PLANS.

There are several different types of PBR plans that focus on limiting the earnings of the regulated company. We review here the two most common forms of such earnings-based PBR plans: banded rate of return regulation and earnings sharing regulation. First, though, we review the central features of rate of return regulation.

A. Rate of Return Regulation.

PBR plans often are viewed as alternatives to rate of return regulation ("RORR"). Therefore, to fully understand the rationale for PBR plans and their potential merits, it is helpful to review the purpose and the key features of RORR.

RORR is designed primarily to ensure that the regulated firm ("the company") can continually attract the capital it requires to deliver high quality, reliable service to customers. RORR typically pursues this goal through substantial regulatory oversight of the company's operations.

Under RORR, the company often is required to secure explicit regulatory approval for each major capital investment it undertakes. The regulator sets prices for the company's services to provide the company a reasonable opportunity to recover its prudently incurred operating expenses and earn a "fair return" on prudently incurred capital investment (AUC PBR Principle 2). The company typically is precluded from earning substantially more than the authorized return under RORR, no matter how exceptional the company's performance might be. Provided the company's

[15] Guthrie (2006, p. 966).

investments are ultimately judged to have been prudent, RORR typically protects the company against financial returns that are substantially less than the authorized return.[16]

In addition to holding hearings to assess the prudency of particular investments, RORR typically schedules general rate hearings fairly frequently to re-set the company's prices to ensure that the company's actual earnings do not diverge substantially from its authorized earnings. The company's earnings usually are monitored on an ongoing basis, and the regulator can initiate additional hearings if preliminary evidence suggests that the company's earnings have diverged substantially from authorized levels.

RORR entails both advantages and disadvantages relative to other policies. The primary potential advantages of RORR include the following four. First, by providing a relatively predictable return on investment, RORR can help the company attract capital and reduce the company's cost of capital.[17] Second, even as it encourages prudent investment, RORR can limit excessive capital investment. It can do so by requiring *ex ante* regulatory approval for major investment projects and by undertaking *ex post* reviews of the prudency of these projects after observing the extent to which the investments have proved to be used and useful in delivering high quality service to customers.

Third, RORR can avoid complaints from customers that they are being required to finance "excessive" returns for the company. Fourth, by providing returns that are sufficient to attract needed capital, RORR can limit the likelihood that customers will experience extended service interruptions or inadequate service quality (AUC PBR Principles 1 and 2).[18]

RORR also entails at least five disadvantages relative to other regulatory plans. First, RORR typically provides the company with limited incentive to minimize operating costs or otherwise realize exceptional performance. This is the case because prices are set under RORR to provide the company with (only) a fair return on investment regardless of the extent to which the company has reduced its operating costs or has otherwise exhibited exemplary performance.

Second, because the minimum rate of return required to attract investment capital can be difficult to determine precisely, RORR can provide excessive or insufficient incentive for capital

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16 The prudence of an investment is appropriately judged according to what the company knew and what it could reasonably have known at the time the investment was undertaken (Kolbe and Tye, 1991).

17 See Fazzari et al. (1988), for example.

18 Indeed, to the extent that the regulator views the company's expenditures to enhance service quality as prudent, RORR can promote the delivery of high levels of service quality by ensuring that the firm is fully compensated for the associated expenditures.

investment. If the authorized return on investment exceeds the return required to attract adequate levels of investment capital, the company may have an incentive to undertake more than the cost-minimizing level of investment. In contrast, if investors do not find the authorized return to be commensurate with the returns they can secure on other investments of comparable risk, the company may be unable to attract the capital it requires to operate efficiently.

Third, RORR can provide the company with limited incentives to choose capital and non-capital inputs in cost-minimizing proportions (and so may be inconsistent with AUC PBR Principle 1). This is the case in part because the authorized compensation for capital investment may exceed or fall short of the level required to attract essential capital investment and in part because RORR offers little explicit financial reward for minimizing its overall operating costs.[19]

Fourth, the implementation of RORR typically requires considerable regulatory resources (and so may be inconsistent with AUC PBR Principle 2). The determination of a company's cost of capital and its capital investment needs can be a time consuming and resource intensive process. Detailed *ex ante* and *ex post* assessments of the prudency of individual capital investment projects also entails the expenditure of considerable regulatory resources, as does the ongoing monitoring of the company's realized earnings.

Fifth, confiscatory *ex post* prudence reviews can limit the company's incentive to pursue needed capital investment. Whether the confiscatory nature of a review is intentional (to secure lower prices for customers in the short run) or unintentional (e.g., caused by limited information about relevant industry considerations), the prospect of a review that prevents the company from securing a reasonable return on investments that appear prudent *ex ante* reduce the attraction of investment. The prospect of confiscatory prudence reviews also limits the firm's ability to attract capital, and so can limit the company's ability to deliver uninterrupted, high quality service to customers.[20]

B. Banded Rate of Return Regulation.

Banded rate of return regulation ("BRORR") is much like RORR, with one important exception. BRORR allows the company's earnings to vary with its observed performance, but typically only to a limited extent. In particular, if the company's realized earnings exceed a

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[19] Despite substantial theoretical interest in this "Averch-Johnson bias" (Averch and Johnson, 1962), empirical support for the bias is not extensive. Cicala (2015) provides some recent evidence.

[20] See Kolbe and Tye (1991), for example.

specified target level of earnings (or target rate of return on investment) by a modest amount, the prices the company charges to its customers are not reduced to eliminate the "excess" earnings. Similarly, if the company's actual earnings fall below the target level of earnings, the company's prices are not increased to eliminate the earnings "deficit." Consequently, the company receives some reward for achieving earnings above a target level and incurs a penalty if its earnings fall below the target.

The essence of BRORR is illustrated in Figure 1. The figure depicts the relationship between the company's "unadjusted earnings" and its "authorized earnings." The former are the earnings the company would secure if the prices it charges to customers remain at the levels established at the outset of the BRORR regime. The latter are the earnings the company secures after any relevant price adjustments are implemented in response to an observed divergence between the firm's unadjusted earnings and its target level of earnings (E_T).

BRORR entails the specification of a critical level of earnings (E_L) below the target and another critical level of earnings (E_H) above the target. As long as the company's unadjusted earnings are between E_L and E_H, the company's prices are not revised. If the company's unadjusted earnings rise above E_H, prices are reduced to ensure the company secures earnings E_H. If the company's unadjusted earnings fall below E_L, prices are increased to ensure the company's earnings are E_L.

This relationship between the company's unadjusted earnings and its authorized earnings are reflected in the solid line in Figure 1. Regardless of the firm's unadjusted earnings, authorized earnings never fall below E_L or rise above E_H. When unadjusted earnings are between E_L and E_H, authorized earnings coincide with unadjusted earnings.

Relative to RORR, BRORR enhances the company's incentive to reduce its operating costs when its unadjusted earnings are between E_L and E_H. When unadjusted earnings are in this range under BRORR, the company effectively: (i) keeps each extra dollar of cost savings it achieves; and (ii) forfeits a dollar for each extra dollar of cost increase it experiences.[21] Therefore, at least

[21] This is why the solid line in Figure 1 has a slope of 1 when the company's unadjusted earnings are between E_L and E_H.

within the specified range of unadjusted earnings, BRORR provides incentives for cost containment similar to those that arise in competitive markets (AUC PBR Principle 1).[22]

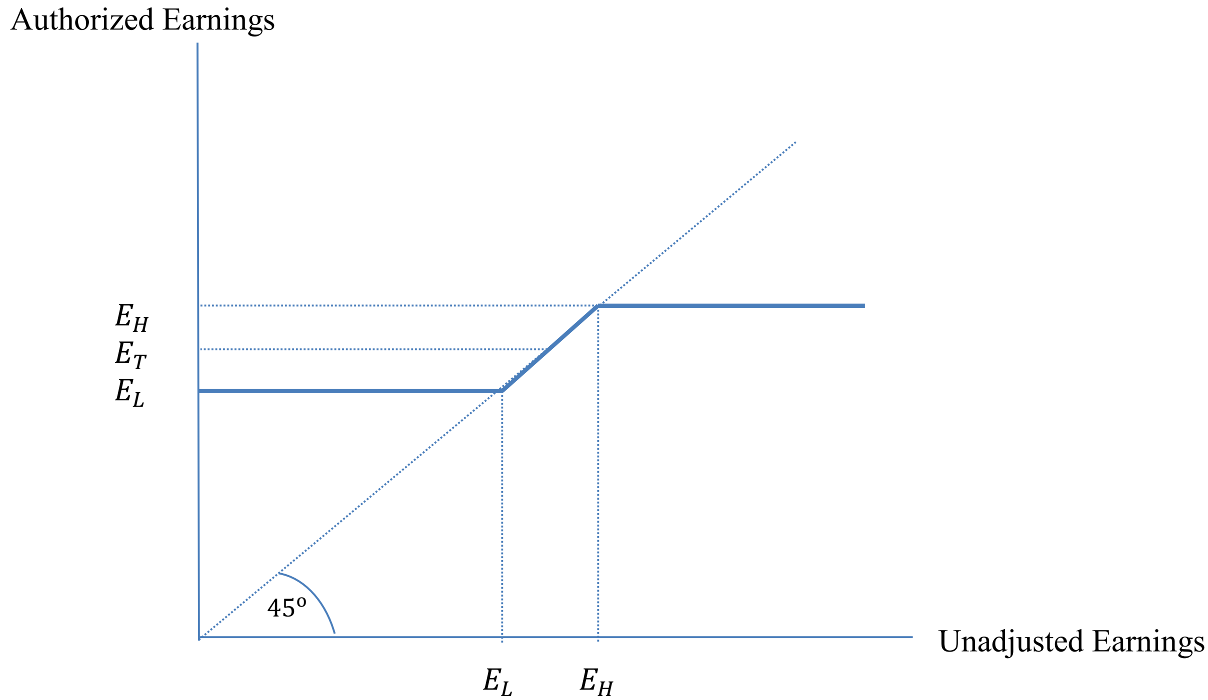

Figure 1. Banded Rate of Return Regulation

Typical values for E_L and E_H under a BRORR plan correspond to earnings that are 100 basis points below and above the target rate of return, respectively. For instance, if the target rate of return on investment is 10%, E_L would correspond to a 9% return on investment and E_H would correspond to an 11% return on investment. Consequently, whereas the company's prices might be revised whenever the company's unadjusted earnings diverged significantly from a 10% return on investment under RORR, price revisions would only occur under BRORR when the company experienced unadjusted earnings that constituted returns on investment below 9% or in excess of 11%.

The magnitude of the difference between the highest and the lowest authorized earnings (i.e., between E_H and E_L) under BRORR determines the extent to which BRORR differs from RORR.

[22] In a competitive market, a firm keeps every dollar of profit it generates (not counting taxes). Therefore, the relationship between unadjusted earnings and authorized earnings for a firm that operates in a competitive market is given by the 45° line in Figure 1.

The smaller is this magnitude, the more similar are the two regulatory policies.[23] The larger is $E_H - E_L$, the closer are the company's incentives to the incentives a firm faces in a competitive market. As $E_H - E_L$ increases, the company faces more potential earnings variation, and the range of earnings in which the firm bears the full consequences of increased or diminished unadjusted earnings expands.[24]

The increased potential variation in authorized earnings typically will enhance the company's incentive to operate efficiently because the firm: (i) has an increased opportunity to benefit financially from any cost reductions it achieves; and (ii) faces an expanded threat of financial penalties from any cost increases it experiences. The increased potential earnings variation also can increase the company's cost of capital because investors typically demand a higher level of expected compensation when they face increased downside risk. In addition, the increased potential earnings variation can conceivably invite criticism from customers that the company's earnings are too high or from the company and its shareholders that earnings are too low.

As the company's unadjusted earnings approach E_H from below, the company's incentive to undertake activities that might secure a substantial increase in unadjusted earnings becomes very limited. Most of any additional earnings the company might realize would accrue to consumers in this case because the firm's authorized earnings are capped at E_H. Similarly, as the company's unadjusted earnings approach E_L from above, the company's incentive to work diligently to avoid a decline in unadjusted earnings becomes limited. Most of any reduced earnings that might arise will effectively be borne by customers in this case because the company's authorized earnings are bounded from below at E_L. Consequently, as the company's unadjusted earnings rise toward E_H from below or decline toward E_L from above, the company's incentives can more closely resemble the incentives the company faces under RORR than the incentives it would face in a competitive market.

To help ensure that the company delivers high levels of service quality under BRORR, authorized earnings can be explicitly linked to realized levels of service quality. For example, the

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23 RORR can be viewed as an extreme form of BRORR in which E_L, E_T, and E_H all coincide. Consequently, the range of unadjusted earnings in which RORR provides incentives similar to those that arise in competitive markets is effectively degenerate.

24 The AUC's PBR plan might be viewed as a form of BRORR because the terms of the plan can be revisited if a company experiences a variation in earnings of more than 300 basis in any two consecutive years or a variation of more than 500 basis points in any single year. See 2012 Commission Decision at ¶¶ 737-738.

BRORR plan might state that E_L and E_H will both be reduced by specific amounts if realized service quality falls below a designated level. Alternatively, or in addition, the plan might identify amounts by which E_L and E_H will be increased if realized service quality attains or exceeds a specified target.[25, 26]

C. Earnings Sharing Regulation.

Earnings sharing regulation ("ESR") is much like BRORR except that it admits greater flexibility in the manner in which earnings that diverge from a target level of earnings are shared between the company and its customers.[27] Relative to BRORR plans, ESR plans often institute sharing over a broader range of earnings and implement intermediate levels of sharing, so incremental earnings do not necessarily accrue entirely to the company or entirely to its customers (AUC PBR Principle 5).

A typical ESR plan is illustrated in Figure 2. This figure, like Figure 1, depicts the relationship between the company's unadjusted earnings (which are the company's earnings if prices remain at the levels established at the start of the ESR plan) and the company's authorized earnings (which are its earnings after any price adjustments that are undertaken to implement the specified sharing of earnings). Under the ESR plan depicted in Figure 2, the company's authorized earnings coincide with its unadjusted earnings when these earnings are between E_1 and E_2.[28] Therefore, as the company's unadjusted earnings increase between E_1 and E_2, the company is authorized to keep all of the incremental earnings (as under BRORR).

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25 The company's authorized return under RORR might similarly be linked to the level of service quality the company delivers.

26 AUC PBR Principle 1 calls for service quality to be maintained under PBR.

27 Earnings sharing regulation is sometimes referred to as "sliding-scale regulation" (e.g., Braeutigam and Panzar, 1993; Lyon, 1996).

28 Figure 2 reflects this coincidence of earnings with the solid line segment that has a slope of 1 for unadjusted earnings between E_1 and E_2.

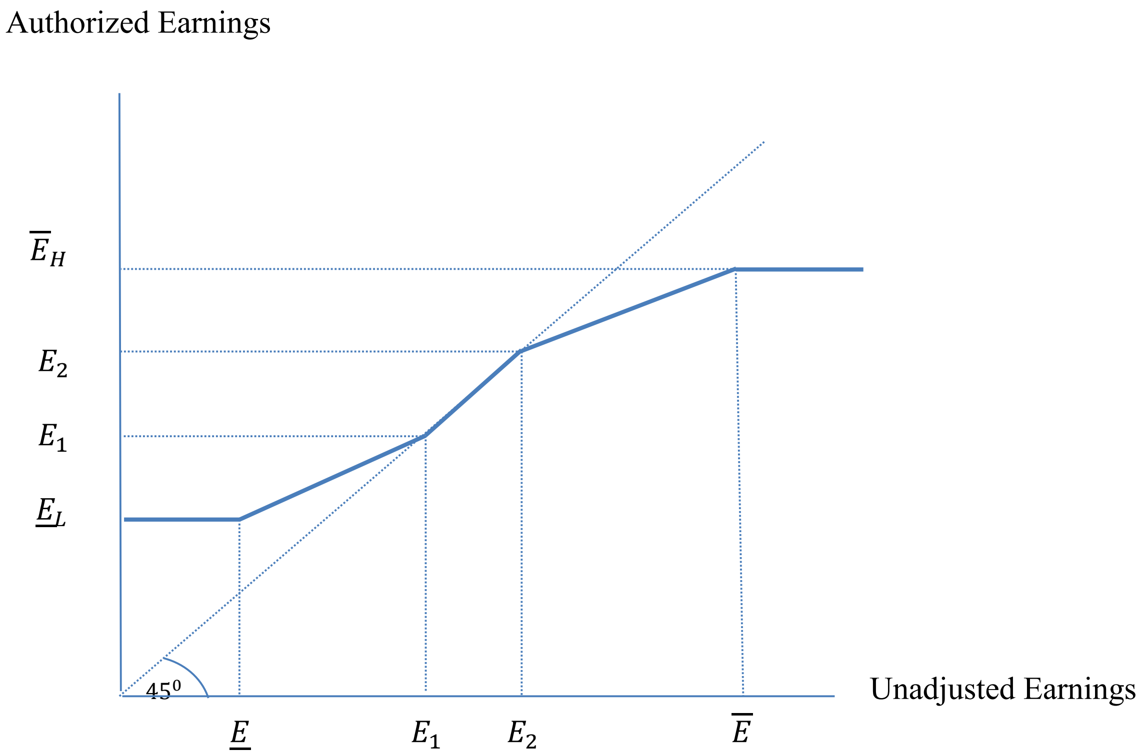

Figure 2. Earnings Sharing Regulation

As the company's unadjusted earnings increase above E_2 toward $\overline{E}$, the company is authorized to keep a fraction (e.g., one half) of the incremental earnings. The remainder of the incremental earnings is awarded to customers.[29] Thus, both the company and its customers benefit as the company's earnings increase between E_2 and $\overline{E}$ in Figure 2 (AUC PBR Principle 5).[30] Once the company's unadjusted earnings reach $\overline{E}$, though, all incremental earnings accrue to customers. Thus, the company's authorized earnings are capped at $\overline{E}_H$ in Figure 2.

[29] The relevant portion of incremental earnings can be awarded to consumers in different ways. For instance, the prices charged to customers might be reduced. Alternatively, a bill credit might be awarded to all customers at the end of each year. The incremental earnings might also be employed to create or expand a program that provides rate relief for low income customers, for example.

[30] Observe that the solid line segment that appears above the unadjusted earnings between E_2 and $\overline{E}$ in Figure 2 has a slope between 0 and 1. This slope captures the explicit sharing of incremental earnings by the company and its customers. The larger is this slope, the larger is the fraction of incremental earnings that is awarded to the company.

The ESR plan depicted in Figure 2 also places a lower bound ($\underline{E_L}$) on the company's authorized earnings and implements a sharing of the incremental "loss" the company experiences as its unadjusted earnings decline below E_1 toward $\underline{E}$. As unadjusted earnings decline in this region, prices are increased to elevate the company's earnings above the level the company would experience in the absence of any price adjustment.[31] If unadjusted earnings decline below $\underline{E}$, prices are raised commensurately to ensure that the company's earnings never decline below $\underline{E_L}$. This lower bound on authorized earnings might represent, for example, the minimum level of earnings the company can tolerate without experiencing pronounced difficulty in attracting capital, serious risk of service interruptions, and/or a substantial decline in service quality.

To provide illustrative numbers, $\underline{E}$, $\underline{E_L}$, E_1, E_2, $\overline{E_H}$, and $\overline{E}$ might be 7%, 8%, 9%, 11%, 12%, and 13%, respectively. In this case, the firm's authorized earnings coincide with its unadjusted earnings whenever these earnings constitute a return on investment between 9% and 11%. As unadjusted earnings increase between 11% and 13%, the company and its customers each receive one half of the incremental earnings. The company is not permitted to earn more than a 12% return on investment. As unadjusted earnings decline below a 9% return on investment toward a 7% return on investment, prices are increased sufficiently to ensure the company and its customers share the incremental decline in earnings equally.[32] Prices are further elevated, as necessary, to ensure the company's earnings never fall below a 7% return on investment in this example.

The primary difference between ESR and BRORR is the less abrupt changes in the allocation of incremental earnings under ESR. In particular, the company receives some, but not all, of the incremental earnings it generates as its unadjusted earnings increase above E_2 under the ESR plan in Figure 2. Consequently, although the company's incentive to generate additional earnings are diminished once its unadjusted earnings rise to E_2, the incentive is not eliminated entirely.[33]

[31] This lower level of earnings is represented in Figure 2 by the height of the 45^{o} line above unadjusted earnings between $\underline{E}$ and E_1.

[32] The fraction of incremental earnings awarded to the company can be explicitly linked to the level of service quality the company delivers. Such linkage can help to ensure that the company does not increase its earnings by reducing service quality unduly.

[33] The diminished incentive to generate additional earnings implies that the company has some incentive to engage in what Blackmon (1994) refers to as "regulatory abuse." This abuse entails expenditures on resources that the regulated firm would not undertake if it had to bear their full cost. Notice that a firm that is required to share 50 cents of each additional dollar of earnings effectively bears only 50 cents of each additional dollar of expense.

Similarly, although the company's incentive to avoid additional reductions in unadjusted earnings is diminished once these earnings fall below E_1, the incentive is not eliminated. Consequently, depending on the details of its design, an ESR plan can provide more pronounced incentives for efficient operation than a BRORR plan.[34]

The potential flexibility of ESR plans raises the possibility that a regulator might find it advantageous to implement different ESR plans for different regulated companies (AUC PBR Principle 4). To illustrate, consider the following setting. Suppose a regulator oversees the operations of two regulated firms. Company 1 is known to operate efficiently, but requires extensive investment to replace aging infrastructure. Company 2 enjoys a modern infrastructure but is believed to operate the infrastructure inefficiently. In this setting, the regulator's primary tasks are to encourage investment in company 1's infrastructure and to motivate company 2 to operate more efficiently.

The regulator might design distinct ESR plans to pursue these two distinct tasks. The regulator might implement an ESR plan for company 1 that: (i) ensures the company's authorized earnings never fall below a relatively high level; and (ii) implements a corresponding relatively modest ceiling on the maximum earnings the company can attain. This ESR plan also might award to company 1 only a modest share of the incremental unadjusted earnings it generates between the specified lower and upper bounds on earnings.

The regulator might implement a very different ESR plan for company 2. The plan might entail a relatively pronounced range in which company 2's authorized earnings can vary. Furthermore, company 2 might be awarded a relatively generous share of the incremental unadjusted earnings it generates within the specified range.

The ESR plan implemented for company 1 can help to ensure that its shareholders receive a substantial, steady return on their investment in the company. The ESR plan implemented for company 2 can provide it with strong incentives to improve its operating efficiency in order to increase its unadjusted earnings (and thus its authorized earnings). More generally, the substantial flexibility that ESR plans admit can enable a regulator to serve customers well by tailoring the ESR plan to the prevailing regulatory goals and industry conditions.

Even when an ESR plan is reasonably well tailored to the prevailing environment, though, it can still introduce many of the drawbacks that arise under RORR and BRORR, and therefore be

[34] Schmalensee (1989) and Lyon (1996), among others, discuss the potential merits of and drawbacks to ESR plans.

inconsistent with AUC PBR Principle 1. In particular, by restricting the company's earnings, ESR can limit the company's incentive to minimize operating costs and to otherwise realize exceptional performance.[35] Furthermore, because it entails ongoing monitoring of earnings, ESR can require substantial regulatory resources and therefore violate AUC PBR Principle 3. In addition, ESR plans can encourage regulators to disallow the company's expenditures on the grounds that they have been incurred imprudently. Such disallowances can increase the company's measured earnings and thereby obligate the company to deliver more "shared earnings" to customers.[36,37] The prospect of such disallowances can limit the company's incentive to pursue costly innovative activities even when the activities likely would serve customers well.[38]

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35 ESR also can encourage strategic intertemporal cost shifting. To illustrate, a company that operates under ESR may delay costly maintenance to future years when earnings are otherwise expected to increase to levels that require the sharing of incremental earnings with customers.

36 See Sappington and Weisman (2010), for example.

37 An example of this phenomenon was presented during the AUC's 2012 PBR hearings. SBC (now AT&T), a telecommunications firm operating in the U.S., operated under an earnings sharing plan in 1993. Massive floods arose in SBC's operating territory during the summer of that year, causing pervasive service outages. The Missouri Public Service Commission questioned the manner in which SBC restored these outages and deemed that a substantial amount of costs had been incurred imprudently. The cost disallowances that followed increased the company's measured earnings into a range where the firm was required to share earnings with customers. These events prompted SBC to petition its regulators for a price cap regime without earnings sharing. See AUC (April 27, 2012, Proceedings, Volume 10, p. 1887).

38 Earnings sharing can sometimes be implemented in less transparent ways. For example, the extent to which the regulated company's prices are adjusted to reflect significant, exogenous (Z factor) events might vary with the level of the company's prevailing earnings. Alternatively, or in addition, future X factors might be ratcheted upward to extract a portion of current earnings retroactively.

III. PRICE-BASED PBR PLANS.

Unlike earnings-based PBR plans that seek to instill competitive discipline by constraining earnings, price-based PBR plans seek to instill competitive discipline by constraining prices. The recent literature on incentive regulation suggests that price-based regulatory plans often provide stronger incentives for efficient operation than do earnings-based regulatory plans.[39] The superior incentive properties of price-based regimes arise when these regimes sever the link between the regulated company's costs and the prices it is permitted to charge for its services. The following passage is instructive.

> It is possible to conclude that under a properly articulated economic rationale, consumer protection against "excessive profits", as traditionally applied under profit regulation, could not be invoked to reestablish a necessary link between prices and profits. . . . In effect, therefore, the standard of constitutional protection for consumers under a price level regime would be modified. The focus would shift from protection against "excessive profits" *per se*, as defined under profit level regulation, to protection against prices viewed as "unconscionable" and "demonstrably irrelevant" to the purposes of the price level regime. (Hillman and Braeutigam, 1989, pp. 80-81)

Pure price cap regulation can present regulated companies with incentives similar to the incentives that prevail in competitive markets.[40] In particular, price cap regulation can present companies with strong incentives to: (1) adopt the least-cost production technology; (2) operate this technology efficiently; (3) diversify efficiently into new markets; (4) undertake efficient levels of cost-reducing innovation; (5) allocate costs appropriately; and (6) report costs truthfully. These strong incentives for efficient performance reflect the fact that pure price cap regulation operates much like a *fixed-price contract*, under which payment for a service rendered does not vary with the realized cost of performing the service. Consumers benefit from a *fixed-price contract* because the prices they pay do not vary directly with the company's realized operating costs. Consequently, consumers bear little or no risk of price variation during the price cap regime. Conversely, traditional rate of return regulation (and some forms of price cap regulation with earnings sharing)

[39] See Braeutigam and Panzar (1989), Sappington (1994, 2002), and Armstrong and Sappington (2006), for example.

[40] The term "pure price cap regulation" refers to a price-based regulatory regime in which there is no earnings sharing with consumers, regardless of the level of the earnings secured by the regulated company.

operate much like a *cost-plus contract*. In particular, the prices consumers pay increase as the company's realized costs increase. Consequently, these prices can exhibit considerable volatility.

Although price cap regulation can provide strong incentives for efficient operation, it can admit very high or very low earnings. The prospect of extreme earnings can undermine regulator's commitment to the regulatory regime.[41]

> …Can the regulator credibly pre-commit to a system of price cap regulation? Stated differently, can today's regulatory commission bind its successor? A regulatory agency is likely to be subjected to considerable political pressure to change the price cap or price cap formula over time. If a firm regulated by price caps begins to earn large profits, consumers will no doubt petition the regulator to lower the price in the core market (Braeutigam and Panzar, 1989, p. 320).
>
> This issue of recontracting and the efficiency distortions resulting therefrom is arguably one of the more serious problems with PC [Price Cap] regulation in practice. A key premise underlying PC regulation is that increased profits for the firm will be viewed by regulators and their constituency as something other than failure of regulation itself. If this premise is false, then regulators will be under constant political pressure to recontract when the firm reports higher profits. In equilibrium, the firm learns that this is how the game is played and the efficiency gains from PC regulation in theory may fail to materialize in practice (Weisman, 993, pp. 364-65).

If not implemented appropriately, a severed link between prices and costs also could jeopardize service quality and reliability. When a company can secure higher earnings by reducing its operating costs, the company may be tempted to reduce its costs by allowing service quality and reliability to decline. This decline was identified as a potential problem in the early days of incentive regulation in the telecommunications industry. However, the empirical evidence generally does not support a strong causal link between incentive regulation and reduced service quality.[42] This may be the case in part because price-based PBR generally is accompanied by explicit restrictions on the level of service quality the regulated company must deliver.[43]

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[41] See Weisman (2002) for further discussion of regulatory commitment and regulatory opportunism under price cap regulation.

[42] See Banerjee (2003) and Sappington (2003, 2005), for example.

[43] Ter-Martiroysyan and Kwoka (2010) find that although service outages do not occur more frequently under incentive regulation, the outages that do arise tend to persist for longer durations. The authors note that reductions in service quality can be avoided with explicit financial penalties for sub-standard levels of service quality. See Sappington (2005) for further discussion of the complexities inherent in designing reward/penalty schemes for efficient provisioning of service quality.

We now consider the central advantages and disadvantages of eight distinct types of price-based PBR plans. The eight plans considered here are not the only price-based PBR plans that might conceivably be implemented in Alberta. Rather, the plans are intended to reflect a representative sample of plans that have been adopted elsewhere and/or might reasonably be afforded serious consideration for possible adoption in Alberta.

A. Partial Price Caps with Bifurcation of CAPEX and OPEX and a Mid-Term CAPEX Update.

The first plan we consider contains elements of both earnings-based regulation and price-based regulation. Under this plan, CAPEX is subject to traditional rate of return regulation, whereas OPEX is subject to price cap regulation. Specifically, the company is afforded the opportunity to earn a fair return on prudently incurred capital investment. Compensation for operating expenses is governed by a price cap mechanism which limits the direct link between authorized revenues and current operating expenses. At the outset of the PBR regime, the company's aggregate revenue requirement is partitioned into a component associated with CAPEX and a component associated with OPEX. The disaggregated revenue requirement forms the basis for the rate structure implemented by the Commission. Over the course of the PBR regime, the annual adjustment to aggregate rates under the $I - X$ index is limited to the OPEX component of the revenue requirement. The price cap mechanism takes the form of pure price cap regulation because it entails no earnings sharing.

A key feature of this PBR plan is the mid-term CAPEX update. Under this plan, the company provides a CAPEX forecast at the beginning of the regime and an updated CAPEX forecast at the mid-point of the regime. This update recognizes that: (i) the company may have somewhat less control over CAPEX than OPEX;[44] and (ii) the inherent uncertainty associated with CAPEX can make it very difficult for the company to forecast CAPEX over the entire duration of the PBR regime, particularly when the length of the regime is pronounced.

The rationale for treating CAPEX and OPEX differently under the PBR plan merits additional discussion. As a public utility with: (i) a carrier-of-last resort obligation; (ii) the obligation to maintain adequate service quality and reliability; and (iii) little or no discretion regarding the markets to be served and the timeframe over which to serve them, the company's capital requirements are driven in significant part by exogenous factors, including population growth and

[44] See Kwoka (2009), for example, for a discussion of why this is likely to be the case.

consumption trends. Furthermore, the long-lived, lumpy nature of capital for public utilities implies that realized costs may diverge significantly from expected revenues. In contrast, utilities typically can fine-tune the processes and procedures they employ to control operating costs, and these costs tend to be relatively predictable.

As is the case with all PBR plans, this plan with bifurcated treatment of CAPEX and OPEX entails both advantages and disadvantage, which are now considered in turn.

The potential advantages of this bifurcated PBR plan include the following four. First, a predictable return on investment can encourage investment, help the company attract capital, and perhaps reduce the company's cost of capital (AUC PBR Principle 2). The ability to attract capital on reasonable terms can be of particular value in the rapidly-growing Alberta economy, which requires considerable infrastructure investment. Second, required *ex ante* approval for capital investment, coupled with *ex post* prudence reviews, can limit incentives for excessive capital investment. Third, high-powered incentives are focused on activities over which the company has the most control.[45] Fourth, the mid-term review recognizes the complexities inherent in forecasting CAPEX over the entire PBR regime, while eliminating administratively burdensome annual rate cases (AUC PBR Principle 3). Furthermore, if a company were forced to forecast CAPEX over the course of the entire PBR regime, it might conceivably have an incentive to overstate capital requirements in order to reduce the likelihood of reductions in service quality.

Professor John Kwoka presents evidence of under-investment in CAPEX under PBR plans that treat CAPEX and OPEX symmetrically under a simple price cap plan similar to those employed extensively in the telecommunications sector. He further points out that a number of states in the U.S. have adopted a hybrid approach to PBR in which OPEX is subject to price cap regulation, but CAPEX is subject to some variant of rate of return regulation. These observations underlie his recommendation for treating CAPEX and OPEX differently under PBR plans.

> The under-investment problem under incentive regulation is likely to be most acute under plans that cap price at a level intended to cover both capital and operating costs, leaving to the utility decisions about expenditures on each. … This understanding has prompted regulators to modify incentive plans so as to treat operating and capital costs

[45] The power of a regulatory regime refers to the fraction of realized cost savings the regulated company is permitted to retain. Pure price cap regulation is considered a high-powered regulatory regime because the regulated company is permitted to keep all of the cost savings it secures during the price cap regime. In contrast, rate of return regulation is considered a low-powered regulatory regime because the firm is typically is required to return to customers in the form of lower prices all of the cost savings that arise. See, for example, Laffont and Tirole (1993, p. 11).

> differently. The most common variant involves the use of straightforward incentive regulation for operating costs but more traditional regulation of the utility's investment. This reflects the … fact that incentive regulation seems well designed for conservation of operating costs, but less well suited to investment behavior and costs. This hybrid approach may in fact capture the comparative advantage of each mode of regulation (Kwoka, 2009, p. 15).
>
> The simplicity of incentive regulation has over time given way to recognition of the need for modifications to address quality and investment issues. Neither of these latter objectives is likely to be satisfied by a plan that simply sets price or the parameters of a pricing formula. … With respect to capital investment, there is a widespread view that some form of rate of return regulation may have a comparative advantage over incentive regulation. For this reason most alternative approaches combine incentive regulation for operating costs with some form of traditional cost-based regulation for investment decisions (Kwoka, 2009, p. 22).

Professor Kwoka's reference to the need to sacrifice some degree of simplicity in the design of PBR plans in order to address "quality and investment issues" figured prominently in the AUC's 2012 PBR proceeding. As discussed in Section I above, the Commission initially favored the simpler approach commonly employed in the telecommunications industry, whereas the companies had serious concerns that this approach could lead to capital deficiencies during the PBR regime.

The potential disadvantages of this PBR plan with a bifurcated treatment of CAPEX and OPEX include the following six. First, the company may have excessive incentive to undertake capital investment if the authorized return exceeds the company's cost of capital. Second, the company may have insufficient incentive to undertake capital investment if the authorized return falls short of the company's cost of capital. Third, the company may have limited incentive to choose capital and non-capital inputs in cost-minimizing proportions, in violation of AUC PBR Principle 1. The incentive to undertake excessive CAPEX in this framework may be even more pronounced than under traditional rate of return regulation. This is the case because the company is fully compensated for CAPEX that can serve to reduce OPEX. The reduced operating costs, in turn, can augment the company's profit under price-based regulation of OPEX if the lower costs increase the company's price-cost margins.[46] Consequently, the bifurcated treatment of CAPEX

[46] EPCOR testified in the 2012 PBR proceeding that increases in CAPEX would not generally lead to reductions in OPEX. EPCOR (August 16, 2013, ¶¶ 135-136). In specific cases (e.g., automatic meter reading), increases in CAPEX would be expected to lead to reductions in OPEX. In the telecommunications industry, the substitution of capital for labor has dramatically reduced the number of employees per access line.

and OPEX could limit the extent to which consumers share the benefits generated by PBR (AUC PBR Principle 5).

Third, the determination of a company's cost of capital and its capital investment needs can be a time-consuming, resource-intensive, and imperfect process, thereby violating AUC PBR Principle 3. Fourth, confiscatory *ex post* prudence reviews can limit incentives for capital investment. Fifth, in practice, it can be more difficult to infer from available historic data the rate at which operating costs alone are likely to change over time than to infer the rate at which all costs are likely to change. As a result, an OPEX-specific *X* factor may be difficult to estimate accurately. The AUC appeared to arrive at this conclusion when it observed "the Commission is not satisfied that there is any acceptable way to create an X factor suitable for use for non-capital-related costs only."[47]

Sixth, the impact of changes in CAPEX on appropriate OPEX-specific *X* factors may be difficult to calculate accurately. For example, the company may be able to reduce OPEX at a rate that exceeds the *X* factor only because it is authorized to increase its capital investment. As a result, it may be difficult to differentiate between endogenous reductions in OPEX that reflect superior performance by the company and exogenous reductions in OPEX that are achieved through Commission-approved CAPEX additions.

It should also be noted that the AUC summarily rejected this approach in the 2012 PBR proceeding, in part because the approach was not viewed as a significant departure from traditional rate of return regulation.[48,49] In other words, it may be difficult to reconcile this approach with AUC PBR Principle 1. In addition, to the extent that this approach retains many of the administratively burdensome aspects of traditional rate of return regulation, this approach may be inconsistent with AUC PBR Principle 3.

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47 AUC Decision 2012-237, ¶ 58.

48 *Id.*

49 The Commission signaled at the outset of the PBR hearings in 2012 that it wished to implement a PBR regime that furthered the process of discovery and innovation that typically is not fostered by traditional rate of return regulation. To this end, the AUC distributed to all parties of record, as a potential aid to questioning by the Commission, the article by Weisman and Pfeifenberger (2003). This article explains why high-powered incentives can outperform regulatory mandates. See AUC (April 11, 2012).

B. Partial Price Caps with Bifurcation of CAPEX and OPEX and No Mid-Term CAPEX Update.

Now consider a closely related PBR plan that does not include a mid-term CAPEX update. Specifically, suppose CAPEX is subject to traditional rate of return regulation, whereas OPEX is subject to price cap regulation. In particular, the company is afforded the opportunity to earn a fair return on prudently incurred capital investment, while recovery of operating expenses is governed by a price cap index that limits the direct link between authorized revenues and current operating expenses. The plan entails no earnings sharing. The one notable difference between this approach and the one described in Section III.A is that the company provides a single CAPEX forecast at the beginning of the regime and does not update the forecast at any point during the PBR regime.

Three of the four primary advantages of this plan parallel the advantages identified in section III.A. First, a predictable return on investment can encourage investment, help the company attract capital, and perhaps reduce the company's cost of capital (AUC PBR Principle 2). Second, required *ex ante* approval for capital investment, coupled with *ex post* prudence reviews, can limit incentives for excessive capital investment. Third, high-powered incentives are focused on the (operating) activities over which the company has the most control. An additional advantage of the present plan is that the absence of a mid-term review of CAPEX reduces the frequency of administratively burdensome rate cases (AUC PBR Principle 3).

The potential disadvantages of this approach are also similar to those discussed in Section III.A, and include the following nine. First, the company may have excessive incentive to undertake capital investment if the authorized return exceeds the company's cost of capital. Second, the company may have insufficient incentive to undertake capital investment if the authorized return falls short of the company's cost of capital. Third, the company may have limited incentive to choose capital and non-capital inputs in cost-minimizing proportions (AUC PBR Principle 1). Fourth, the initial determination of a company's cost of capital and its capital investment needs can be a time-consuming, resource-intensive, and imperfect process (AUC PBR Principle 3). Fifth, confiscatory *ex post* prudence reviews can limit incentives for capital investment.

Sixth, in practice, it may be more difficult to infer from available historic data the rate at which operating costs alone are likely to change than to infer the rate at which all costs are likely to change over time. As a result, an appropriate OPEX-specific X factor can be difficult to calculate accurately. In particular, the calculation of a single X factor that pertains to both CAPEX and

OPEX simply requires the computation of an industry-wide total factor productivity growth rate. Conversely, the calculation of an OPEX-specific X factor requires the computation of a productivity factor for a subset of the inputs employed in the production process. There is no broad-based consensus on how to compute such a disaggregated productivity factor due to the inherent difficulty of identifying the unique contributions of individual factors of production.

Seventh, the impact of changes in CAPEX on appropriate OPEX-specific X factors can be difficult to calculate accurately. Specifically, if capital can be substituted for labor, then the OPEX-specific X factor should be adjusted to reflect Commission-approved CAPEX additions. Such adjustment is likely to be administratively burdensome and complex (AUC PBR Principle 3). Eighth, the absence of a mid-term review could result in actual CAPEX that departs significantly from forecast CAPEX.[50] Ninth, the absence of a mid-term review could motivate the regulator (company) to implement (propose) a regulatory regime of shorter duration, which would reduce incentives for efficiency, particularly if there is an earnings true-up prior to the start of the new PBR regime (AUC PBR Principle 1).[51]

The absence of a mid-term CAPEX forecast raises two important concerns. First, a key tenet of sound incentive regulation is to "limit the firm's financial responsibility for factors beyond its control" (Sappington, 1994, p. 269). Hence, to the extent that the company's limited ability to forecast CAPEX accurately over the entire PBR regime is largely beyond the company's control, it is generally inappropriate to hold the company financially responsible for the associated risk. Second, the company is confronted with a *Hobson's choice* of sorts. If it errs by exaggerating its CAPEX forecast at the outset of the PBR regime to hedge against uncertainty, it risks both future disallowances by the regulator on grounds of imprudence and increased regulatory scrutiny going forward. Such disallowances and increased scrutiny can impose significant costs on all parties. In contrast, if the company experiences a capital deficiency, it may be forced to choose between disappointing investors and permitting service quality to erode and incurring the associated

50 It should be noted in this regard that in the last PBR proceeding, EPCOR's position was that CAPEX forecasts beyond three years were subject to significant uncertainty and could not be deemed reliable in light of rapidly changing conditions in the Alberta economy. EPCOR (July 22, 2011, ¶ 34).

51 An earnings true-up refers to changes in retail rates that are implemented to ensure the regulated company earns its target rate of return. A true-up process can undermine a regulated company's incentives for cost minimization, particularly when true-ups occur frequently. In general, the more frequently an earnings true-up occurs under PBR, the more the plan resembles a *cost-plus contract* and the less it resembles a *fixed-price contract*.

potentially large service-quality penalties.[52] Hence, the benefits of eliminating administratively burdensome rate cases via the elimination of the mid-term review of CAPEX must be balanced carefully against the associated costs, which can be substantial.

C. Price Caps with Capital Trackers and Associated K Factors.

In its 2012 PBR decision, the AUC adopted a price cap plan with capital trackers and associated K factors. Under this plan, a single $I - X$ index governs the company's earnings, and there is no earnings sharing. The X factor reflects historic industry total factor productivity growth rates and company-specific stretch factors determined by the Commission. This index can be modified during the PBR regime by a K factor that reflects the financial consequences of specific capital investment projects as identified in the capital trackers. The projects in question, which must be outside of the normal course of the company's ongoing operations, include projects required by an external party.[53]

To be considered for a K factor adjustment, each individual capital tracker must exceed a materiality threshold.[54] There is no aggregate materiality threshold for all capital trackers combined. There is also no linkage between the magnitude of K factor adjustments and the company's prevailing earnings. The Commission adopted this PBR plan in large part to limit the dilution of the high-powered incentives that arise under pure price cap regulation and in competitive markets (AUC PBR Principle 1).[55]

The potential advantages of this PBR plan include the following five. First, the plan provides incentives for the company to limit overall production costs (both capital costs and operating costs) and to employ capital and non-capital inputs in cost-minimizing proportions (AUC PBR Principle 1). Second, by admitting K factor adjustments, the plan can afford the company a reasonable opportunity to earn a fair return on its investment even in the presence of significant changes in capital costs and capital investment needs (AUC PBR Principle 2). Third, the plan may limit a

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[52] An increase in CAPEX without a corresponding increase in rates can be expected to lower the realized rate of return and disappoint investors.

[53] Examples include: (1) relocation of EDTI's distribution infrastructure at the request of the City of Edmonton; and (2) replacing EDTI's current Interval Meter Data Collection and Processing System ("MDCPS") with a new data collection engine that complies with Measurement Canada's requirements. See EPCOR (December 14, 2012, § 3.1.1).

[54] The materiality threshold is a minimum dollar amount that each proposed capital project must satisfy in order to be given consideration as a capital tracker.

[55] AUC (2013, ¶ 586).

company's uncertainty about its ultimate recovery of capital costs, and thereby encourage capital investment. Fourth, the plan may help to limit rate shock by allowing for rate adjustments (reflecting K factor adjustments) during the course of the PBR regime (AUC PBR Principle 5). Fifth, the plan can help to conserve regulatory resources by only considering capital trackers that exceed a specified materiality threshold (AUC Principle 3).

The potential disadvantages of this plan include the following six. First, price changes based on an X factor that reflects historic industry productivity changes may not ensure adequate compensation for the regulated company when costs are unavoidably increasing over time (AUC Principle 2).[56] Indeed, this was the issue addressed by EPCOR's Category 2 capital trackers that were proposed to address capital funding shortfalls under the $I - X$ index.[57] Specific examples include tools, equipment, and vehicle replacement that would not typically be considered outside the normal course of company operations.

Second, in practice, it can be difficult to distinguish between projects that are outside of the normal course of the company's ongoing operations and those that are not. This issue generated significant discussion in the 2012 PBR proceeding regarding the purported existence of a line of demarcation between so-called baseline CAPEX and incremental CAPEX.[58]

Third, the plan may provide the company with an incentive to identify (and possibly exaggerate) "positive" capital trackers, but overlook (or understate the impact of) "negative" capital trackers.[59] This problem may be particularly acute given the comingling of EPCOR's Category 1 and Category 3 trackers with its Category 2 trackers. Fourth, ongoing adjustments for unusual capital projects might limit incentives to minimize overall production costs (AUC PBR

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56 An X factor that adjusts appropriately for historic industry-specific input price growth rates can provide adequate compensation for a company that operates in a steady-state environment, but potentially not in a setting where investment needs are increasing systematically over time. To the extent that the X factor only reflects historic trends, a stretch factor might be employed to account for expected changes in industry-specific productivity and input price growth rates.

57 EPCOR (December 14, 2012, pp. 67-68).

58 AUC (2012, Volume 10, pp. 1906-1920). EPCOR testified that it was difficult, if not impossible, to disentangle incremental CAPEX from baseline CAPEX. This is the case because when EPCOR undertakes an incremental CAPEX project, it is generally prudent and cost-effective to simultaneously implement other upgrades or replacements that normally would be considered baseline CAPEX.

59 It may be possible to limit this incentive with true-ups and annual *ex ante* reviews of capital tracker projects.

Principle 1).[60] Incentives can be diluted particularly severely by a full true-up of actual CAPEX associated with the capital tracker and forecast CAPEX.[61]

Fifth, despite the project-specific materiality threshold, substantial resources may be required to identify and quantify relevant capital trackers, unless the opportunity to do so is explicitly limited (AUC PBR Principle 3).[62] This is the case because it can be difficult to distinguish between projects that are outside of the normal course of the company‘s ongoing operations and projects that are within the normal course of the company’s operations. In essence, the regulator is required to second-guess the company’s operating practices, a task that is fraught with difficulty. Sixth, the company may not be able to secure adequate earnings if many unanticipated investment projects arise, each of which entails costs below the specified project-specific materiality threshold (AUC PBR Principle 2). In essence, the company may risk “death by a thousand cuts.”

A full true-up of forecast CAPEX and actual CAPEX can undermine incentives for cost containment and work at cross purposes with the high-powered incentives the Commission had sought to preserve in adopting this approach (AUC PBR Principle 1). EPCOR highlighted this concern in its final argument in the capital tracker proceeding (EPCOR, 2013, § 2.2). EPCOR proposed a full true-up of forecast CAPEX and actual CAPEX for Category 1 trackers. In light of the fact that Category 1 trackers are essentially capital-specific Z (exogenous) factors, this approach is consistent with sound incentive regulation principles.

EPCOR proposed two alternatives for strengthening the incentives for cost containment associated with its Category 2 trackers, which it referred to as Alternative 1A and Alternative 1B. Each of these alternatives and their incentives properties are discussed in turn.

Under Alternative 1A, EPCOR would be permitted to true-up its Category 2 Trackers on a prospective basis only, rather than the full, retrospective basis contemplated in the Commission’s Decision. In other words, EPCOR would not be allowed to true-up its capital trackers to actual costs for the period of time between the approval of the Category 2 Tracker and the Commission’s approval of the true-up. Instead, only a prospective true-up would be permitted, beginning at the time the true-up is approved. The prospective true-up would occur only after a stipulated period of

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60 A requirement to demonstrate that the benefit of the proposed new capital investment could not have been achieved at lower cost through other means can help mitigate this potential problem.

61 EPCOR (2013, ¶¶ 60-66).

62 Adjustments for capital trackers might only be permitted at a limited number of times during the PBR regime.

time, ranging from the time remaining in the calendar year to the full remaining term of the PBR regime. When EPCOR effectively is held responsible for cost variances during the period of time between the approval of the Category 2 Capital Tracker and the true-up to actual costs, the company faces strong incentives to undertake only necessary, efficient capital projects.

Under Alternative 1B, EPCOR's ability to true-up its Category 2 Trackers during the PBR term would be limited to the share of the company's annual forecast capital cost for each Category 2 Tracker that is funded by the approved Capital Tracker K factor adjustment (i.e., to the portion of the company's annual forecast capital cost that is not funded by the $I - X$ mechanism). It is noteworthy that the AUC was sufficiently interested in a mechanism by which the incentives for cost containment could be strengthened that it provided the Commission's Aid to Panel Questioning (Exhibit 229) in the capital tracker proceeding.

A slightly modified form of Exhibit 229 permits a demonstration of how the true-up mechanism might work in practice. This demonstration is provided here with the aid of Table 1, which considers two distinct scenarios. Scenario 1 hypothesizes a CAPEX addition in which 50% of the required capital is funded under the $I - X$ index and 50% is funded under the capital tracker. Scenario 2 hypothesizes a CAPEX addition in which 60% of the required capital is funded under the $I - X$ index and the remaining 40% is funded under the capital tracker.

Line (L)		Scenario 1	Scenario 2
		$ Amount	$ Amount
	Forecast Stage:		
L1	Forecast CAPEX Additions	10	10
L2	Covered by $(I - X)$	5	6
L3	Capital Tracker (L1 – L2)	5	4
	True-Up Stage:		
L4	Actual CAPEX Additions	12	12
L5	Variance (L1 – L4)	2	2
L6	Variance Deemed to be Covered by $(I - X)$	1 or (50%)	1.2 or (60%)
L7	Variance Deemed to be Related to Approved Capital Tracker (L5 – L6)	1 or (50%)	0.8 or (40%)
L8	**Tracker True-Up**	**1**	**0.8**

Table 1. Capital Tracker True-Up Mechanics

First consider Scenario 1 in Table 1, where the company forecasts CAPEX Additions of 10, but only 5 are covered under the $I - X$ price cap mechanism. This leaves a residual of 5 to be financed through the capital tracker. In the true-up stage, the company's actual CAPEX Additions are assumed to be 12 rather than 10, which leaves a positive variance of 2 as shown in line L5 of Table 1. Given that 50% of the forecast CAPEX addition is not covered under the $I - X$ index, the company is only able to true-up 50% of the variance, or $0.5 \times 2 = 1$ as shown in lines L7 and L8.

Now consider Scenario 2, where 40% of the forecast CAPEX addition is not covered under the $I - X$ index. In this case, the company is only able to true-up 40% of the variance, or $0.4 \times 2 = 0.8$, as shown in lines L7 and L8. Hence, the risk the company faces, as measured by the responsibility it bears for the variance between forecast and actual CAPEX, is equal to the percentage of the CAPEX additions that are covered by the $I - X$ index.

Another way to envision the risk-bearing attributes of this true-up mechanism is to partition the cost recovery for CAPEX variance into endogenous and exogenous components. A proxy for the endogenous component (i.e., the component that is under the control of the company) is equal to the percentage of CAPEX addition governed by the $I - X$ index. A proxy for the exogenous component (i.e., the component that is beyond the control of the company) is equal to the percentage of the CAPEX addition that is not covered by the $I - X$ index. This approach, which explicitly differentiates between endogenous and exogenous components of the CAPEX variance, is consistent with the principle that a sound PBR regime should "limit the firm's financial responsibility for factors beyond its control" (Sappington, 1994, p. 269). In other words, if the company operated under an $I - X$ index with no capital trackers, it would have no opportunity to seek recourse for funding shortfalls from the regulator, because all required outlays are effectively deemed to be endogenous to the firm. In contrast, for purely exogenous events for which the $I - X$ index provides no funding, the firm would be fully compensated (just as it would be in presence of Z factors) for all prudent CAPEX outlays. Hence, it may be reasonable to limit the true-up between actual outlays and expected outlays to that portion of the expected outlay funded through the capital tracker – the exogenous component.

D. Price Caps with an Incremental Capital Module.

The price cap plan with an incremental capital module is essentially the approach the Ontario Energy Board (OEB) adopted for addressing the complexities presented by incremental CAPEX over the course of the PBR regime.[63] Under this plan, a single $I - X$ index governs the company's earnings and there is no earnings sharing. The X factor reflects historic industry total factor productivity growth rates and company-specific stretch factors determined by the Commission. This index can be modified via K factor adjustments during the course of the PBR regime to reflect specific capital investment projects. Hence, the "capital module" takes the form of an adjustment to the price cap formula to provide adequate funding for special (incremental) capital projects. These projects, which must be outside of the normal course of the company's ongoing operations, include projects required by an external party. To be considered for a K factor adjustment, the entire set of capital trackers in total must exceed a stipulated materiality threshold, but there is no materiality threshold for any individual capital tracker. Finally, the magnitude of K factor adjustments does not vary with the level of the company's prevailing earnings.

The potential advantages of this plan are similar in many respects to the advantages of the plan discussed in Section III.C above. These advantages include the following six. First, because prices are governed by a single $I - X$ index, this plan provides incentives for the company to limit overall production costs (both capital costs and operating costs) and to employ capital and non-capital inputs in cost-minimizing proportions (AUC PBR Principle 1). Second, because it includes K factor adjustments, the plan may afford the company a reasonable opportunity to earn a fair return on its investment even in the presence of significant changes in capital costs and (exogenous) capital investment needs (AUC PBR Principle 2). Third, the plan may limit a company's uncertainty about its ultimate recovery of capital costs, and thereby encourage capital investment. Fourth, the plan can help to limit rate shock by allowing for rate adjustments during the course of the PBR regime. Fifth, the plan conserves on regulatory resources to some extent by only considering capital trackers that, in total, exceed a specified materiality threshold (AUC PBR Principle 3). Six, the aggregate materiality threshold can enable the company to earn an adequate return even when the need arises for several "small" investment projects.

The potential disadvantages of this plan are also similar in many respects to the disadvantages of the plan discussed in Section III.C above. The disadvantages include the following five. First,

[63] It is noteworthy that the OEB retained the incremental capital module (ICM) for its fourth PBR regime, but modified the applicable language to allow for a somewhat broader category of CAPEX applications. Specifically, the language was revised to remove words such as "unusual" and "unanticipated" as prerequisites for an application for incremental capital, although the requirement that the proposed expenditures be non-discretionary remains (OEB, 2012, p. 18). This change may reflect the fact that a more restrictive test for CAPEX applications could increase the risk of capital insufficiency at some point during the PBR regime.

price changes that reflect historic industry productivity changes may not ensure adequate compensation in the presence of costs that increase unavoidably over time (AUC PBR Principle 2). Notably, as discussed in greater detail below, this plan addresses only one of the two predominant sources of revenue inadequacy that a company may encounter over the course of the PBR regime (i.e., exogenous CAPEX additions). Second, in practice, it can be difficult to distinguish between projects that are outside of the normal course of the company's ongoing operations and those that are not. Third, the company may have an incentive to identify (and possibly exaggerate) "positive" capital trackers, but overlook (or understate the impact of) "negative" capital trackers. Fourth, ongoing adjustments for unusual capital projects can limit incentives to minimize overall production costs (AUC PBR Principle 1). Fifth, because there is no materiality threshold on individual projects, substantial resources may be devoted to analyzing proposed capital trackers.

A key difference between this plan and the AUC's current PBR plan concerns the specific categories of capital trackers that are permitted. Under the OEB's incremental capital module approach, EPCOR's Category 1 and Category 3 capital trackers (which reflect capital projects for which the $I - X$ component of the PBR formula provides no funding) would presumably be allowed, but EPCOR's Category 2 trackers (which reflect adjustments for specific projects that are not adequately funded by the $I - X$ component of the PBR formula) would not be allowed. In this sense, the incremental capital module approach is more restrictive than the AUC's current capital tracker approach. To see why, recall that under the AUC's guidelines, if a project is to qualify as a capital tracker, then "the project must be outside of the normal course of the company's ongoing operations."[64] In AUC Decision 2013-435, the Commission adopted a relatively broad interpretation of this condition. Specifically, the Commission allowed for capital trackers in the case of extraordinary projects as well as project-specific expenditures incurred in the course of ongoing operations that were deemed to be not adequately funded under the $I – X$ index.[65] The AUC apparently felt compelled to adopt a broader view of the various sources of exogenous revenue inadequacy than the view reflected in the incremental capital module approach.[66]

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[64] AUC Decision 2012-237, ¶ 592.

[65] AUC Decision 2013-435, § 3.1.3.

[66] It should be noted that the incremental capital module approach was placed on the record in the 2012 PBR proceeding and was addressed in the rebuttal stage of the proceeding by various parties, including EPCOR and the City of Calgary.

E. Price Caps with an *F* Factor ("*K*-Bar") Adjustment.

Under a price cap plan with an F factor adjustment, a single $I - X$ index governs the company's earnings and there is no earnings sharing. The *X* factor reflects historic industry total factor productivity growth rates and company-specific stretch factors determined by the Commission. The company identifies at the start of the PBR regime any additional "F (forward-looking) factor" adjustment that is required for (expected) revenue sufficiency. In essence, the F factor reflects the extent to which the standard $I - X$ index fails to provide the company with the opportunity to earn a fair return on its foreseeable, prudent capital investments over the course of the PBR regime (AUC PBR Principle 2).[67] During the PBR regime, the company can apply for capital trackers that are not known (and not knowable) at the start of the PBR regime. These capital trackers can reflect unique life cycle replacement projects or projects required by a third party for which the $I - X$ component of the PBR formula does not provide compensation.

The relationship between this approach and three categories of capital trackers that EPCOR identified in the capital tracker proceeding merits clarification. Under this approach, EPCOR's Category 1 and Category 3 trackers would be addressed via *K* factors, whereas EPCOR's Category 2 trackers would be addressed via the *F* factor. This bifurcation has the advantage of restricting *K* factors to those categories of capital trackers that the Commission initially envisioned in its 2012 PBR proceeding as the proper domain for *K* factor adjustments. It is further noteworthy that the AUC may have signaled some preliminary support for this approach in its 2013 Capital Tracker proceeding.[68] This approach differs from a price cap plan with an ICM by recognizing at the outset of the PBR regime that because an ICM limits capital trackers to EPCOR's category 1 and category 3 classifications, even an appropriately formulated ICM could leave the company with an exogenous revenue deficiency (i.e., a revenue deficiency through no fault of its own).

The potential advantages of a price cap plan with an F factor adjustment include the following seven. First, the plan allows the company a reasonable opportunity to earn a fair return even in the presence of significant changes in capital costs and capital investment needs (AUC PBR Principle 2). Second, the plan can encourage the company to undertake comprehensive operations planning.

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[67] The *F* factor can change during the course of the PBR regime. However, the specific values of the *F* factor that will prevail in each year should be specified clearly at the outset of the regime to ensure that the *F* factor does not devolve into a "make-whole" safety net for the firm.

[68] Application No. 1606029, Proceeding ID No. 566, Proceedings, Transcripts, Volume 7, pp. 1335-1354, July 17, 2013.

Third, the plan provides incentives for the company to limit overall production costs (both capital costs and operating costs) and to employ capital and non-capital inputs in cost-minimizing proportions (AUC PBR Principle 1).

Fourth, a plan of this type streamlines the regulatory process after the initial forward-looking assessment of prudent capital investment (AUC PBR Principle 3). Fifth, the plan leverages familiarity with telecom style price-cap regulation (and the experience of key AUC Commissioners) while explicitly accounting for the unique characteristics of the energy sector. Sixth, to the extent that foreseeable capital expenses are pre-approved, the plan can encourage investment by reducing the financial risk the company faces.

Seventh, this plan provides for a clear line of demarcation between issues of ongoing financial solvency (EPCOR's Category 2 trackers) and the AUC's initial conception of the qualifying criteria for a capital tracker (EPCOR's Category 1 and Category 3 trackers). By limiting capital trackers to purely exogenous CAPEX, this approach may give rise to more high-powered incentives relative to those reflected in the AUC's current capital tracker approach (discussed in Section III.C above).

The potential disadvantages of a price cap plan with an F factor adjustment include the following four. First, the forward-looking approach the plan entails could provide the company with incentives to exaggerate actual capital investment needs.[69] Second, the initial forward-looking assessment of prudent capital investment requires substantial regulatory resources (AUC PBR Principle 3). Third, the line of demarcation between so-called baseline CAPEX, as reflected in the F factor, and incremental CAPEX, as reflected in the K factor, may be difficult to identify.[70] Fourth, the company may have an incentive to identify (and possibly exaggerate) "positive" capital trackers, but overlook (or understate the impact of) "negative" capital trackers.

F. Price Caps with Limited Factor Adjustments and a Midterm Review.

A price cap plan with a mid-term review but no capital trackers is similar to the price cap plan considered in Section III.E. The plan contemplates a single $I - X$ index that governs the company's

[69] These undesirable incentives can be mitigated to some extent via *ex post* prudence reviews and ongoing comparisons between projected and actual capital investments.

[70] During the 2012 PBR hearings, EPCOR argued that this approach was inherently unworkable due to the complex interrelationships between baseline capital and new capital and the lack of any systematic methodology for distinguishing between the two. See Alberta Utilities Commission (AUC), Rate Regulation Initiative, Application No. 1606029, Proceeding ID No. 566, Proceedings, Volume 10, April 27, 2012, p. 1900 and EPCOR (2012, ¶ 102).

earnings for a specified period of time (e.g., 6 years). There is no earnings sharing. The X factor reflects historic industry total factor productivity growth rates and company-specific stretch factors determined by the Commission. The company has the opportunity to identify at the start of the PBR regime any additional "F factor" adjustment that is relevant. As discussed in detail in Section III.E, the F factor reflects the extent to which the standard $I - X$ index fails to allow the company the opportunity to earn a fair return on its foreseeable prudent capital investments over the course of the PBR regime. The central difference between the plan discussed in Section III.E and the present plan is the inclusion of the option for a single, mid-term "bottom-up" review of capital requirements, with corrections for relevant capital trackers.[71] The present plan also does not permit additional capital trackers during the PBR regime.

Four key features of this review of capital requirements merit emphasis. First, the review is limited to a consideration of projects that were not known (and not knowable) at the start of the PBR regime and that are outside of the normal course of the company's ongoing operations, which include projects required by an external party.[72] Second, the mid-term review does not include a rate of return review, and is not a "top down" review of capital requirements. Third, no mid-term review is conducted if (and only if) both the Commission and the company prefer no review.[73] Fourth, other than at the mid-term review, F factor and K factor adjustments are not permitted during the PBR regime.[74]

The potential advantages of this type of plan are similar to those discussed in Section III.E, and include the following five. First, this plan provides incentives for the company to limit overall production costs (both capital costs and operating costs) (AUC PBR Principle 1). Second, the plan

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[71] A "bottom-up" review of capital requirements evaluates a company's capital requirements on a project-by-project basis, and provides no guarantee that the sum of the capital requirements from all projects combined will permit the company to earn its target rate of return. In contrast, a "top-down" approach determines the aggregate capital requirement that is needed to ensure the company can achieve its target rate of return. In the 2013 Capital Tracker proceeding, the AUC employed the bottom-up review to determine whether the capital trackers proposed by the companies should be approved.

[72] One issue that warrants consideration is whether the regulator can penalize the company at the mid-term review for capacity that exceeds stipulated bounds (or perhaps for failure to meet service quality standards).

[73] To avoid excessive strain on limited regulatory resources during mid-term review years, the timing of reviews for different companies can be staggered appropriately.

[74] One possible variation on this design is to allow for K factor adjustments throughout the course of the PBR regime, but allow for F factor updates only at the time of the mid-term review. This has the benefit of distinguishing clearly between EPCOR's Category 1 and 3 trackers (K factor adjustments) and its Category 2 trackers (F factor update).

motivates the company to assess accurately its long-term investment needs. Third, the initial *F* factor adjustment can afford the company a reasonable opportunity to earn a fair return on its investments even in the presence of significant foreseeable changes in capital costs and capital investment needs (AUC PBR Principle 2). Fourth, plans of this type leverage familiarity with telecom style price-cap regulation (and the experience of key AUC Commissioners) while explicitly accounting for the unique characteristics of the energy sector. Fifth, this plan conserves on regulatory resources during the PBR regime, while allowing for mid-course adjustments that can be important in the energy sector (AUC PBR Principle 3).

Many of the potential disadvantages of this plan parallel those discussed in Section III.E, but some notable differences arise. The potential disadvantages of this plan include the following four. First, the potential for an *F* factor adjustment may provide the company with incentives to exaggerate actual capital investment needs. Second, by precluding capital trackers except at the mid-plan review, the plan may force the company to bear considerable risk and face the prospect of a higher cost of capital. Third, the company may have an incentive at the mid-term review to identify (and possibly exaggerate) "positive" capital trackers, but overlook (or understate the impact of) "negative" capital trackers. Fourth, the Commission may face substantial political pressure to employ the mid-term review as an earnings review, which can reduce the company's incentives to operate efficiently.[75]

Observe that the plan under consideration here allows for *K* factor adjustments at the time of the mid-term review, but does not permit annual *K* factor adjustments. In contrast, the plan discussed in Section III.E does not permit a mid-term *F* factor adjustment, but does allow for annual *K* factor adjustments. Absent further information about the environment in which the company operates, it is not possible to determine which of these plans exposes the company to greater risk. It is conceivable that an inability to seek annual *K* factor adjustments could motivate a company to seek a relatively pronounced mid-term *F* factor adjustment.

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[75] The Massachusetts Commission explicitly declined to review Verizon's earnings when it reviewed the price cap regulation plan, noting that an earnings review could diminish the performance of the regime (Vasington, 2003). The AUC's capital tracker decision may provide support for an approach along these lines by favoring the bottom-up over the top-down approach for capital trackers. Also, the Commission recognized that if it were to review earnings when evaluating the company's capital requirements, it would effectively be employing earnings regulation. See AUC (September 12, 2012, ¶ 212).

G. Partial Price Caps with Bifurcation of CAPEX and OPEX, with a Rolling Average CAPEX Update.

We now consider another PBR plan that employs price cap regulation to limit the prices a company can charge for its regulated services. The plan entails no sharing of earnings and proceeds for a relatively long period of time (e.g., seven to ten years) before the parameters of the plan are revisited. Despite this relatively long duration, the plan does not permit capital trackers. It does, however, admit corrections for Z factor events throughout the course of the PBR regime.[76] The company's capital expenditures during the PBR regime may be subject to *ex post* prudence reviews.

In determining the price cap (i.e., the X factor) that is imposed on the company, the plan treats operating expenses and capital expenses differently. The component of the X factor that is intended to allow the company to recover its OPEX when it operates efficiently is determined in standard fashion. In particular, this component reflects the regulator's assessment of the operating expenses the company will incur annually if it works diligently to control these expenses. This component of the X factor typically does not change throughout the duration of the PBR regime.

The component of the X factor that is intended to permit the company to recover its CAPEX and earn a reasonable return on investment is determined differently. This component varies from year to year. In year t, the component reflects a N-year moving average of the company's capital expenditures, beginning L years before year t. To illustrate, suppose the PBR regime is scheduled to last for ten years, beginning in 2016. Further suppose $N = 5$ and $L = 4$. Then for each year $t =$ 2016, 2017, …, 2025, the relevant component of the X factor in year t reflects the average of the company's CAPEX in years $t - 8$, $t - 7$, $t - 6$, $t - 5$, and $t - 4$.

The choice of the parameter L in this PBR plan is particularly important. The larger is L, the more distant is the historic period that informs the estimate of the company's current capital investment requirements. Consequently, any increase in CAPEX in a given year will only increase the relevant portion of the X factor after a substantial delay.

This PBR plan entails five primary potential advantages. First, the bifurcated treatment of OPEX and CAPEX allows relatively high-powered incentives to be focused on those activities

[76] A relevant Z factor event is one: (i) that does not involve capital investment; (ii) that is unknown (and unknowable) to the company at the start of the PBR regime; (iii) that has a substantial impact on the company's earnings; and (iv) for which both the event and the financial impact of the event on the company's earnings are largely beyond the company's control.

over which the company has the most control. Second, authorized price increases designed to cover the company's capital costs are updated annually throughout the PBR regime rather than being linked solely to an initial estimate of the company's likely CAPEX needs. The annual update can link allowed revenues more closely to actual capital needs to the extent that the company's investment needs change significantly over time and the moving average of the company's historic CAPEX accurately predicts current CAPEX needs.

Third, the PBR plan conserves on regulatory resources by eliminating the use of capital trackers during the course of the PBR regime (AUC PBR Principle 3). Fourth, by linking allowed revenues directly to historic capital expenditures, the plan can limit the company's uncertainty about the ultimate recovery of capital costs, which can encourage capital investment. Fifth, coupling required *ex ante* approval for major capital investments with *ex post* prudence reviews can limit incentives for excessive capital investment.[77] A relatively long lag in relevant CAPEX (i.e., a relatively large value for L) also can help to limit incentives for excessive capital investment.

This PBR plan also entails at least five potential disadvantages, though. First, because the plan automatically increases authorized future revenue as current CAPEX increases, the plan can encourage some capital over-investment and may not provide strong incentives to reduce capital expenditures. Second, if a substantial lag (i.e., a relatively high value of L) is employed in the plan, authorized revenues will only increase to cover capital expenditures with a significant delay. Consequently, the plan could discourage the company from undertaking needed investment.[78] Third, the plan may consistently underestimate CAPEX needs if these needs are increasing systematically over time.

Fourth, identifying the best values for the N and L parameters can be difficult, in practice (AUC PBR Principle 3). For the reasons explained above, a lag that is too long can discourage investment unduly, whereas a lag that is too short could encourage over-investment (by quickly and automatically translating higher capital expenditures into higher revenues).[79] Fifth, by

[77] *Ex post* prudence reviews may not be advisable if the time lag on the moving average computation is sufficiently long. A sufficiently long lag can eliminate strategic incentives to inflate CAPEX, and so an *ex post* prudence review might serve primarily to invite regulatory opportunism.

[78] Penalties for inadequate service quality can help to enhance the company's incentive to undertake the capital expenditures required to ensure the ongoing delivery of adequate levels of service quality.

[79] Ideally, the values of N and L also should be chosen so that the moving average of historic CAPEX that is calculated each year closely approximates the company's CAPEX needs in that year. Such approximation may be possible if there are systematic cycles in required capital expenditures.

weakening the link between current capital expenditures and current authorized revenue, the plan could permit earnings well above or well below a normal rate of return in any given year. The risk associated with this earnings variation could increase the company's cost of capital.

H. Options in the Choice of Regulatory Regime.

The discussion to this point has focused on settings where the regulator designs a specific PBR for a company rather than providing the company with a choice among PBR plans. Sometimes, though, regulators can better serve customers by affording the company some choice among PBR plans.[80]

To illustrate this more general point, consider a setting where the regulator would like to implement a PBR plan that provides strong incentives for the company to operate efficiently. A price cap ("$I - X$") policy that severs the link between allowed prices and realized costs can provide such incentives. However, such a policy can permit the company to secure very high earnings (if the selected X factor is unduly low) or restrict the firm to very low earnings (if the selected X factor is unduly high). If the regulator is committed to implement a price cap policy when (s)he faces substantial uncertainty about the most appropriate value of the X factor, (s)he may set a relatively low X factor to avoid subjecting the company to financial distress. Such a policy will induce the company to operate efficiently, but may produce relatively high prices for customers (due to the low X factor) and possibly excess returns for the company.

Alternatively, the regulator might afford the company a choice between, say, a price cap ($I - X$) plan and rate of return regulation.[81] By doing so, the regulator can set a relatively high X factor (and thereby secure relatively low prices for customers under the price cap plan) without fear of subjecting the company to financial distress. When the company believes it would suffer financial distress under the challenging price cap plan, it will instead choose to operate under rate of return regulation. In contrast, when the company is confident that it can secure relatively high earnings even under the challenging price cap plan, it will choose to operate under this plan rather than under rate of return regulation. In this event, the regulator will have succeeded in implementing a

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[80] Sappington and Weisman (1996), Sappington (2004), and Joskow (2014), among others, explain the potential benefits of allowing regulated companies to choose one regulatory plan from a carefully designed set of regulatory plans.

[81] Sappington and Weisman (1996) describe different choices that regulators have afforded companies in the telecommunications sector. Joskow (2014) describes options that have been implemented in the energy sector.

plan that provides strong incentives for efficient operation and secures for customers lower prices than they would have faced had the regulator restricted herself to necessarily implementing a price cap plan (and consequently imposing a relatively modest X factor in order to avoid financial distress).

This example illustrates the more general conclusion that when the regulated company is well informed about its capabilities and its environment but the regulator's corresponding knowledge is limited, the regulator can sometimes best serve customers by affording the company a choice among regulatory plans. Such choice can enable the regulator to design (and often secure) PBR plans that are quite favorable to customers with little risk of imposing financial distress on the company. This is the primary potential advantage of affording a company a choice among regulatory plans.

Such choice can introduce at least three potential disadvantages, though. First, the company may ultimately not choose the plan preferred by the regulator. For instance, in the example described above, the company may ultimately choose to operate under rate of return regulation rather than price cap regulation. Thus, although customers may often gain when the company is afforded a choice among regulatory plans, customers do not always gain. Second, it can be challenging both to design an appropriate set of options to offer to the company and to convince customers that they are being well served when the company is afforded a choice among regulatory plans.

Third, and relatedly, the design, implementation, and administration of optional PBR plans can be challenging and require considerable regulatory resources. Consequently, optional PBR plans may be inconsistent with AUC PBR Principle 3. Fourth, a company may secure undue profit by choosing strategically among regulatory plans over time. To illustrate, the company might initially choose to operate under rate of return regulation and later choose to operate under price cap regulation. When operating under rate of return regulation, the company might attempt to over-invest in capital-intensive technologies that reduce future operating costs. The firm might later benefit significantly from the resulting cost reductions that arise when it operates under price cap regulation.[82]

The Ontario Energy Board afforded the companies under its jurisdiction a choice among three PBR plans in 2012. The plans allows the companies to choose among: (1) an annual incentive

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[82] Such strategic behavior can be limited by restricting the company's ability to choose freely among the prevailing options over time.

regulation index; (2) a fourth generation incentive regulation plan; and (3) custom incentive regulation.

The annual incentive regulation index is a price cap regulation plan that is intended for companies with "primarily sustainment investment needs." Therefore, the plan does not permit capital trackers. A company that chooses this plan must file a five-year investment plan. However, the required filing is less detailed than the filing required under the other plans. A company can choose this plan as long as it is not earning more than 300 basis points above its approved annual return on equity. There is no fixed term for the plan, so a company that operates under this plan can request an alternative plan at any time.

The fourth generation incentive regulation plan is a five-year price cap plan that is intended for most companies under the jurisdiction of the Ontario Energy Board. The *X* factor specified in the plan reflects historic industry average productivity growth rates, along with firm-specific stretch factors specified by the Commission. A company that selects this plan can apply for an adjustment to the *X* factor to reflect unusual anticipated capital investment needs.

The custom incentive regulation plan is a price cap plan with a duration of at least five years that is intended "for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels."[83] The plan does not include capital trackers. However, the *X* factor and the associated prices established under the plan reflect the conclusions of a comprehensive operating plan that includes anticipated capital investments. The Commission monitors the capital expenditures of each company that chooses this plan, and can terminate the plan if actual and planned expenditures differ substantially.

Options like these have the potential to tailor the PBR plan to the prevailing environment. Such tailoring can be particularly valuable when different companies face very different operating conditions. However, the design and implementation of optional PBR plans like these can require considerable regulatory resources.[84] Furthermore, it can sometimes be difficult for regulators to explain to constituents why they are permitting a regulated company to choose its preferred PBR

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[83] Report of the Ontario Energy Board (2012, p. 19).

[84] As Sappington (1994, p. 260) observes, "Allowing for a choice among incentive plans can complicate the regulatory task, thereby sacrificing simplicity." Perhaps in part for this reason, the AUC did not appear to support the options approach in the recent PBR proceeding. See, in particular, AUC Decision 2012-237, ¶¶ 273-276.

plan rather than dictating the plan under which the company must operate. Perhaps for these reasons, optional PBR plans are not common in practice.

IV. CONCLUSION.

A. SUMMARY.

This report was commissioned by EPCOR to identify and evaluate the merits of potential alternative approaches to the treatment of capital in PBR regimes. The report analyzed three earnings-based PBR plans and eight price-based PBR plans. The advantages and disadvantages of each were assessed, and references to the relevant economics literature were provided to facilitate further analysis. The report also selectively identified the specific AUC PBR Principles that applied to the various advantages and disadvantages of each approach. This exercise was intended to assist EPCOR in evaluating the various approaches through the same lens that the AUC is likely to employ for the next PBR regime.

This report reveals at least two outstanding issues that EPCOR may wish to address prior to the termination of the current PBR regime. First, it is not apparent why an *X* factor that incorporates both productivity growth and input price differentials appropriately will fail to provide adequate compensation for a regulated company operating in a *steady-state*.[85] Second, in the 2012 PBR proceeding, EPCOR proposed a linkage between service quality performance and the efficiency-carryover mechanism. While the AUC did not adopt EPCOR's proposal, the Commission appeared to have some interest in a mechanism that linked service quality performance to the parameters of the price cap plan. The specific manner in which service quality performance should be linked to the parameters of the price cap plan is a complex question that warrants careful thought and analysis.

B. PRELIMINARY RECOMMENDATION.

Our preliminary recommendation with respect to the preferred approaches is based on four main criteria. First, the AUC is unlikely to adopt any approach containing elements of traditional rate of return regulation. Second, the AUC places a large premium on simplicity, transparency and reducing the regulatory burden for all parties. Third, the preferred approaches should address the issue of capital sufficiency in a comprehensive and principled manner. Finally, it is critical that the preferred approaches provide strong incentives for efficiency comparable to those that arise in competitive markets.

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[85] Stated differently, it remains to specify precise conditions under which it is important to include Category 2 capital trackers in a PBR plan.

Based on the analysis set forth in the body of this report, our preliminary recommendation is that the AUC adopt a pure price cap approach that incorporates an economically principled mechanism capable of addressing all three of the capital tracker categories that EPCOR identified in the course of the 2013 Capital Tracker proceeding. We believe this approach addresses both company and Commission concerns while preserving to the extent possible the desirable incentives that arise in competitive markets. This suggests that the following three approaches merit the most serious consideration:

(1) PRICE CAPS WITH AN F FACTOR ("$\bar{K}$ -BAR") ADJUSTMENT **(III.E)**

(2) PRICE CAPS WITH LIMITED FACTOR ADJUSTMENTS AND A MIDTERM REVIEW **(III.F)**

(3) PRICE CAPS WITH CAPITAL TRACKERS AND ASSOCIATED K FACTORS (**III.C**)

In addition, we believe that the OPTIONS IN THE CHOICE OF REGULATORY REGIME (**III.H**) approach, which allows the regulated firm a limited choice among PBR plans, has considerable appeal. Recall that the Ontario Energy Board adopted this approach in its last PBR proceeding. Despite its potential merits, this approach is not included among our preliminary recommendations for two primary reasons. First, the AUC appeared to dismiss this approach out of hand in the 2012 PBR proceeding. Second, this approach entails potentially complex design issues and has encountered some difficulties in practice.

Finally, it is important to note that our preliminary recommendation does not reflect an explicit, systematic ranking of the eleven approaches from the perspective of the AUC's five PBR Principles. In subsequent analysis, EPCOR may see merit in undertaking a more formal assessment of each of the approaches from the perspective of the AUC's PBR Principles. This exercise may allow for a more refined ranking of the various approaches and better position the company to support the approach that it ultimately adopts for the next-generation PBR regime.

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Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix HH

Summary of BC Hydro's Internal Audits

Table of Contents

1 Listing of Internal Audits – Fiscal 2017, Fiscal 2018 and Fiscal 2019 To-Date

Audit Services performs internal audits of key areas of BC Hydro. Independent Subject Matter Experts are engaged when expertise is required on the audit subject. Since fiscal 2017, experts have assisted Audit Services from various areas of the world including Canada, United Kingdom, Switzerland, Norway, and the United States.

At the conclusion of the audit, the overall audit is ranked based on the identified issues and associated impacts. The ranking can range from a green with minor issues to red with critical issues.

	Minor issues and impacts identified
	Moderate issues and impacts identified
	Significant issues and impacts identified
	Critical issues and impacts identified

All audits are approved by the BC Hydro Audit and Finance Committee of the Board. Management is responsible for the providing Action Plans to address the recommendations from the audit. Audit Services continues to monitor management's progress to address each recommendation until completion.

2 Fiscal 2017

2.1 Independent Power Producers Contract Management

Objective: Assess whether in-service Independent Power Producers and BC Hydro adhere to Electricity Purchase Agreement terms and processes exist to effectively manage contracts.

Conclusion: Moderate issues and impacts identified. Appropriate oversight is in place. Independent Power Producers meet obligations for energy delivery. Parties are generally in compliance with the key terms and conditions. Management of agreements is sometimes reactive including resolution and reporting of invoice variances. Improvement opportunities include documentation, internal reporting and development of key performance indicators.

2.2 Demand Side Management

Objective: Assess whether effective processes and controls are in place over Demand Side Management activities and programs.

Subject Matter Expert: Engaged from GDS Canada Consulting Ltd. with over 40 years of experience including performing impact, process and market effects evaluations, and managing energy efficiency programs. The expert was also a Certified Measurement and Verification Professional.

Conclusion: Minor issues and impacts identified. Processes and controls are in place for Demand Side Management planning, program development, implementation and evaluation. Improvement opportunities include simplifying the planning process, documentation of assumptions and processes and developing a central assumptions database.

2.3 Site C Contract Procurement

Objective: Review the Site C procurement practices and assess whether contract placements follow a competitive, open and fair process.

Conclusion: Minor issues and impacts identified. Contracts were placed following a fair and competitive process. Sourcing bid documents were prepared with input from subject matter experts and rigorous evaluation processes were undertaken. Independent Fairness Advisors were involved throughout the entire procurement process to ensure fairness and transparency. Improvement opportunities include retaining approvals and implementing a formal document control process.

2.4 Generation Maintenance

Objective: Provide assurance there is an effective Generation Maintenance program to ensure assets are well maintained.

Conclusion: Minor issues and impacts identified. A strong governance framework is in place over the Program. Effective processes have been implemented to plan maintenance work and facilities are generally complying with maintenance practice requirements. A detailed reporting process has been established to monitor performance. Improvement opportunities include developing a process to review higher risk corrective and condition-based work orders, continuing to develop a data analytics program and to better integrate maintenance and capital planning and decision making.

2.5 Customer Connection Process

Objective: Review the effectiveness of the end-to-end customer connection process.

Conclusion: Moderate issues and impacts identified. The governance structure is in place to oversee the Customer Connect group. Significant progress has been made since the last audit. Work streams are well managed with reporting tools in place. Collaborative efforts among stakeholders are required to address: accuracy of estimates and cost allocations, update of drawings as built and management of material need dates. Other areas to be resolved include legacy billing issues, handling of payments and invoicing for Distribution Design and backlogs in system extension test calculations.

2.6 Disaster Preparedness

Objective: Assess BC Hydro's plans and ability to respond to, and recover from, a catastrophic disruption of business operations.

Subject Matter Expert: Engaged from PwC's business resilience practice in Western Canada with 20 years of experience in this field. Led many engagements assisting multi-national organizations to develop and implement disaster preparedness and recovery programs.

Conclusion: Moderate issues and impacts identified. Significant progress has been made in the Program since the last audit. An effective governance structure and framework has been formulated but not fully implemented. Emergency management plans, exercise and training programs are in place. Recommendations include further enhancements in enterprise-wide business impact analysis, business continuity, IT disaster recovery and corrective action plans to move the Emergency Management Program forward.

2.7 Site C Contract Management

Objective: Review contract management processes to assess whether effective controls are in place.

Conclusion: Moderate issues and impacts identified. Strong oversight is in place at both project and contract management levels with comprehensive reporting to the Board, Executive, and Project Director level. In general, invoices and change orders are reviewed in detail and approved for timely payment. Improvement opportunities include reviewing resourcing capacity, clarifying roles and responsibilities, and accelerating enhancements to the IT contract management system.

2.8 John Hart Replacement Project

Objective: Provide assurance that the John Hart Replacement Project is being appropriately executed to ensure delivery of stated objectives.

Conclusion: Minor issues and impacts identified. The Project is on track to deliver the stated objectives. Project oversight includes a strong governance structure, clear assignment of responsibilities and effective reporting. BC Hydro is monitoring and auditing work performed by the private sector partner to verify compliance with the Agreement. Contract management processes are in place to ensure invoices are reviewed, tracked and approved prior to payment and contract changes are tightly controlled.

3 Fiscal 2018

3.1 BC Hydro Business and Travel Expenses

Objective: Assess compliance with employee business and travel expense policies and procedures.

Conclusion: Minor issues and impacts identified**.** Management oversight is in place to monitor expenses. Business and travel expenses for the board of directors, executives and employees are compliant with corporate policies with some notable exceptions. Management will address spending decisions which may not fully align with the policy requirements, and review policies needing further clarity.

3.2 Load Forecasting

Objective: Review the load forecasting process to ensure timely and reliable energy and peak demand forecasts which supports operational, financial and strategic planning at BC Hydro.

Subject Matter Expert: Engaged from GDS Associates Inc. with over 30 years of load forecasting experience including preparing load forecasts for various utility clients (ranging from day-ahead to long-term horizons), and filing testimony on issues relating to load forecasting and other statistical analyses.

Conclusion: Minor issues and impacts identified. Overall, the load forecasting function at BC Hydro compares favorably to industry standards and to other large electric utilities in North America. No critical weaknesses were found. Load forecasting methodologies are consistent with best practices and load forecast outputs are provided to users and stakeholders on a timely basis. The greatest risk of load forecasting inaccuracy falls on the industrial class and is due to the uncertainty of future economic activity and the volatility of many individual customer loads. Improvement opportunities relate to making adjustments to forecast models and inputs to enhance overall forecast accuracy.

3.3 Engineering Service Provider Contracts

Objective: Review whether effective processes and controls are in place to ensure Engineering Service Providers are fulfilling their contractual obligations.

Conclusion: Minor issues and impacts identified. An established governance framework with oversight over Engineering Service Providers exists. Effective monitoring, reporting and relationship management processes are in place. Service provider invoices were verified and reviewed for accuracy and reasonableness, properly approved and paid in a timely manner. Data analytics revealed no significant overcharges or errors. Improvement opportunities relate to inefficiencies in invoice verification processes and requesting documentation from Service Providers to support expenses claims.

3.4 Horne Payne Substation Upgrade Project

Objective: Provide assurance the Horne Payne Substation Upgrade project is managed and executed to deliver stated objectives.

Conclusion: Minor issues and impacts identified. The project is appropriately managed and work is being executed to deliver the stated objectives. A governance framework is in place and the project is on track to be completed on scope, schedule and below the expected cost. The project is mostly compliant with key management plans. There are design challenges during construction potentially due to the design review processes at the time. Management of larger contracts is effective while further monitoring of smaller contracts is required.

3.5 Construction Services

Objective: Assess whether Construction Services effectively manages and delivers work to meet client needs.

Conclusion: Moderate issues and impacts identified. Overall, governance is in place and clients are highly satisfied with the quality of work. Business processes have been developed and implemented for job planning, construction and completion but these processes are not consistently followed. Reporting is in place to monitor operations however reliability of some performance metrics is impacted by data integrity issues.

3.6 Project Portfolio Management

Objective: Assess whether there is compliance with Project and Portfolio Management requirements and the effectiveness of the quality assurance function.

Conclusion: Minor issues and impacts identified. Project and Portfolio Management compliance is in place to support strong project management practices, and key tools are functioning as designed. The approach used in the quality assurance processes is appropriate, however, modifications will be required to further strengthen the methodology and ensure changes are made as issues are identified.

3.7 Indigenous Relations Agreement Management

Objective: Assess whether BC Hydro is effectively executing agreements in support of its Indigenous Relations Strategy.

Conclusion: Moderate issues and impacts identified. BC Hydro is fulfilling commitments based on audit testing. However, management practices vary depending on the type of agreement, and tracking of commitments is inconsistent. The current systems and existing processes do not fully enable the management of agreements, commitment tracking, and reporting. With the increasing volume and scope of commitments, it is essential to have standardized systems and controls that are consistently being applied. Improvement opportunities include strengthening processes and controls, addressing data integrity and reducing reliance on individual employees.

3.8 Enterprise Billing Infrastructure Project

Objective: Provide assurance during implementation that the Enterprise Billing Infrastructure Project was being effectively executed to attain project objectives.

Subject Matter Expert: Engaged from PwC with over 40 years of advising Boards and CEOs on large and complex projects and initiatives. Expert has extensive experience with business and technology solutions for corporate and public sector clients.

Conclusion: Minor issues and impacts identified. The Project was effectively executed to deliver its stated objectives. Although there were some significant risks identified by the Project Team early in the project, appropriate actions were identified and undertaken to mitigate these risks.

4 Fiscal 2019 To-Date

4.1 Dam Safety

Objective: Evaluate whether risks are identified, prioritized, and managed to ensure objectives of BC Hydro's Dam Safety Program are achieved.

Subject Matter Experts: Two experts were engaged. The first expert is the Commissioner for Dam Safety at the Swiss Federal Office of Energy. The second expert is a Professional Engineer at Health & Safety Executive (**HSE**) Major Hazards division. HSE is Great Britain's statutory regulator of occupational health and safety requirements.

Conclusion: Minor issues and impacts identified. BC Hydro has a well-established Dam Safety Program that is in line with international practices. Governance is effective with appropriate oversight, and the relationship with the regulator is strong and forthcoming. A robust risk assessment process continues to drive key dam safety activities, and operational activities are executed to monitor dams. Risk factors relating to management of the Issues Database and surveillance activities are minor on their own, but together could be an indication that elements of the Dam Safety Program may be falling behind.

4.2 Smart Meter Operations

Objective: Assess whether the Smart Meter system is fully operationalized, managed and functioning effectively.

Subject Matter Expert: Engaged from Bridge Energy Group with extensive experience in technology strategy, enterprise architecture, integration and security to utility clients. Subject matter expert also provided expertise on the fiscal 2013 Meter-to-Bill Audit.

Conclusion: Minor issues and impacts identified. The Smart Metering System is delivering intended services to the stakeholders with controls around data and application security, access and privacy. Operations are effectively governed largely due to legacy relationships from the Project and the system is well monitored.

Executive sponsorship and strategic governance need to be established to align business objectives and priorities. Improvement opportunities include testing and deployment of the technology and improved integration of meter data into the Outage Management System.

4.3 Confined Space Program

Objective: Assess whether an effective Confined Space Program is in place and being followed.

Conclusion: Moderate issues and impacts identified. Significant effort has been made to operationalize the Program across the organization including identifying and inventorying confined spaces, developing risk assessments and work procedures. Improvement opportunities include reviewing the current oversight model, implementing compliance monitoring processes and improving documentation practices to ensure worker safety and regulatory compliance.

4.4 Energy Studies Process

Objective: Evaluates whether the monthly Energy Studies process reliably supports operations, financial and strategic planning at BC Hydro.

Subject Matter Experts: Two subject matter experts engaged from SINTEF. A senior research scientist working with load forecasting, risk management, hydro scheduling and hydrothermal market modelling, and a research scientist working with development and analyses related to hydrothermal market models and medium-term hydropower scheduling models. Both scientists held Doctorates from the Norwegian University of Science and Technology.

Conclusion: Minor issues and impacts identified. BC Hydro has a well-established Energy Studies process in place. Governance is effective with appropriate level of oversight, and responsibilities and accountabilities are well understood across the team. Key models developed are appropriate and the methodologies applied are in line with leading industry practices. The Energy Study process can be further automated to reduce cycle time and free up resources. Energy Study reports are prepared on time and contain an appropriate level of detail; however they do not serve short-term operational planning needs.

4.5 Learning and Development

Objective: Assess the effectiveness of learning and development to ensure employees have the right skills at the right time.

Conclusion: Moderate issues and impacts identified. Learning opportunities are provided for employees. Processes are in place to identify required training needs, develop course curriculum, and deliver training to employees. Managers cannot effectively monitor and confirm employees have completed the required safety training for assigned work. Improvement opportunities include developing an overarching training policy for the organization and addressing limitations of the Qualification and Learning Management System.

4.6 Cheakamus Generator Replacement Project

Objective: Provide assurance that the Cheakamus Units 1 and 2 Generator Replacement Project is appropriately managed and executed to deliver stated objectives.

Conclusion: Minor issues and impacts identified. The project is on course to meet budget and schedule and is being managed and monitored appropriately. A clear governance framework is in place to support project delivery. Contracts are generally well-managed and procured in compliance with BC Hydro policies and procedures. Improvement opportunities include risk register updates, clarifying requirements around final inspections prior to signing Commissioning Notice to Operate, and periodically completing quality reviews of the transmittals and submittals log.

BC Hydro
Power smart

Fiscal 2020 to Fiscal 2021
Revenue Requirements Application

Appendix II

Abbreviations

Abbreviations

A

ABS	Accenture Business Services
AMI	Automated metering infrastructure
Application	Fiscal 2020 to Fiscal 2021 Revenue Requirements Application
AROR	Average rate of return
ASAI	Average Service Availability Index
ASC	Accounting Standards Codification
AUC	Alberta Utilities Commission

B

BC Hydro	British Columbia Hydro and Power Authority
BCEAO	British Columbia Environmental Assessment Office
BCTC	British Columbia Transmission Corporation
BCUC	British Columbia Utilities Commission
BES	Bulk electric system
BOABC	Building Officials' Association of British Columbia
BR1	Bridge River 1
BR2	Bridge River 2
BRP	Base Resource Plan
BRT	Bridge River Terminal

C

CADD	Computer-Aided Design and Drafting
CAIDI	Customer Average Interruption Duration Index
CAP	Capilano Substation
CAPEX	Capital expenditures

Capital Plan	BC Hydro's Fiscal 2020 to Fiscal 2024 Capital Plan
CBL	Customer baseline load
CBN	Clayburn Substation
CEA	*Clean Energy Act* or Canadian Electricity Association
CEA Agency	Canadian Environmental Assessment Agency
CEATI	Centre for Energy Advancement Through Technical Innovation
CGAAP	Canadian Generally Accepted Accounting Principles
CHBA	Canadian Home Builders Association
CHL	Customer hours lost
CHP	Combined heat and power
CIDC	Calgary Internet Data Centre
CIP	Critical Infrastructure Program
CKY	Cheekye Substation
CLRA	Contingent Labour Resource Augmentation Project
CO^2e	Carbon doxide equivalent
COD	Commercial operation date
Comprehensive Review	The Government of B.C.'s Comprehensive Review of BC Hydro
COO	Chief Operating Officer
COPOA	Co-Processors and Operating Agreement
COSR	Cost of service regulation
CPCN	Certificate of Public Convenience and Necessity
CPI	Consumer Price Index
CRSP	Canadian registered safety professional
CRTC	Canadian Radio-Television and Telecommunications Commission
CSA	Canadian Standards Association
CSQ	Cathedral Square Substation

D

DACS	Data and Analytics Centre
DARR	Deferral Account Rate Rider
DCAT	Dawson Creek/Chetwynd Area Transmission
D-COMS	Distribution Contract and Operations Management Services
Decision	BCUC's Decision on BC Hydro's Fiscal 2017 - Fiscal 2019 Revenue Requirements Application, released March 1, 2018
DEER	Database for energy efficiency resources
DGR	Dal Grauer Substation
DSM	Demand-side management

E

EAR	Expenditure authorization request
EARSL	Expected average remaining service life
EC&E	Energy Conservation and Efficiency Committee
ECAP	Energy Conservation Assistance Program
ECM	Efficient carryover mechanism
ECMS	Energy conservation measures
EDTI	Edmonton Distribution and Transmission Incorporated
EHR	Equipment Health Rating
EIA	Energy Information Administration (U.S.)
EIS	Environmental Impact Statement
EM&V	Evaluation, Measurement and Verification
EOC	Evaluation Oversight Committee
EOL	End-of-life
EPA	Electricity Purchase Agreement
EPCOR	Edmonton Power Corporation
ESK	Energy Savings Kit

ESM	Earnings sharing mechanisms
EVP	Energy visualization portal

F

FAAP	Financial Approval Authority Policy, (BC Hydro's employee expenditure limit policy)
FCC	Federal Communications Commission (U.S.)
FERC	Federal Energy Regulation Commission (U.S.)
First Full Funding	Baseline of a total project estimate and schedule associated with the first implementation EAR approval.
FOICO	Freedom of Information Coordinating Office
FOIPPA	*Freedom of Information and Protection of Privacy Act*
FortisBC Energy Inc.	FortisBC, gas distribution utility
FortisBC Inc.	FortisBC, integrated electricity utility serving customers in the southern interior of B.C.
FTE	Full Time Equivalent

G

GAAP	Generally Accepted Accounting Principles
GBL	Generator Baseline Load
GDP	Gross Domestic Product
GGRR	Greenhouse Gas Reduction Regulation
GHG	Greenhouse gas
GIS	Gas insulated switchgear
GJ	Gigajoule
GLD	Gold River Substation
GLT	Glouchester Substation
GMS	Gordon M. Shrum Generating Station
GOW	Goward Substation
GRTA	Generation Related Transmission Assets

GWh	Gigawatt-hour

H

HDA	Heritage Deferral Account
HLH	High load hours
HPN	Horne Payne Substation
HPS	High-pressure sodium
HPU	Hydraulic power units
HSY	Horsey Substation
HVAC	Heating, ventilation and air conditioning

I

IAS	International Accounting Standard
IBA	Impact Benefit Agreement
IBEW	International Brotherhood of Electrical Workers
ICBC	Insurance Corporation of British Columbia
IEP	Integrated Electricity Plan
IFRIC	International Financial Reporting Interpretations Committee
IFRS	International Financial Reporting Standards
IMS	Incident Management System (Safety)
INOG	Intake operating gates
IOMA	Initiative Operations, Maintenance or Administration
IPMVP	International Performance Measurement and Verification Protocol
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ISD	In Service Date
ISO	International Organization for Standardization
ITA	Industry Training Authority

ITDSP	Information Technology Delivery Standard Practices

J

JOR	Jordan River Substation

K

KBU	Key Business Unit
KIDC	Kamloops Internet Data Centre
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour

L

LCE	Low-carbon electrification
LDR	Ladore Generating Station
LED	Light emitting diode
LEEP	Local Energy Efficiently Partnerships
LEM	Leaders in Energy Management
LEM-C	Leaders in Energy Management - Commercial
LEM-I	Leaders in Energy Management - Industrial
LGS	Large General Service, refers to the rate class of large commercial and small industrial customers with demand greater than 150 kilowatts
LLH	Low load hours
LLO	Low Level Outlet
LMU	Line matching unit
LNG	Liquefied natural gas
Load Forecast	BC Hydro’s Fiscal 2020-2024 Load and Revenue Forecast, released in October 2018.
Load Forecast Audit	BC Hydro’s internal audit on the load forecasting function.

LRMC	Long-Run Marginal Cost
LTAP	Long Term Acquisition Plan

M

M&V	Measurement and Verification
MAIFI	Momentary Average Interruption Frequency Index
MCA	Mica Generating Station
MDE	Maximum design earthquake
MDMS	Meter Data Management System
MDN	Meridian Substation
MES	Maintenance and Emergency Stockpile of riprap
MGS	Medium General Service, refers to the rate class of commercial customers with electricity demand of greater than 35 kilowatts and less than 150 kilowatts
Mid-C	Mid-Columbia Day Ahead Price
MLE	Mount Lehman Substation
MNT	Metro North Transmission
MoveUP	Movement of United Professionals (Formally Canadian Office and Professional Employees Union)
MPLS	Multiprotocol label switching
MPT	Mount Pleasant Substation
MSA	Master Supply Agreement
MUR	Murrin Substation
MV	Mercury vapor
MW	Megawatt – one million watts or one thousand kilowatts

N

NERC	North American Electricity Reliability Corporation
NERC-CIP	North American Electricity Reliability Corporation Critical Infrastructure Program
NFOM	Non-fuel operations and maintenance expenses

NHDA	Non-Heritage Deferral Account
NIA	Non-Integrated Area
NIARG	Non-Integrated Area Ratepayers Group
NIC	Nicola Substation
NITS	Network Integration Transmission Service
NOR	Norgate Substation
NPV	Net Present Value
NTL	Natal Substation

O

O/H	Overhead
OAG	Office of the Auditor General (British Columbia)
OATT	Open Access Transmission Tariff
OEB	Ontario Energy Board
OLTC	On-load tap chargers
OMA	Operations, Maintenance or Administration
OPEX	Operating expenditures
OSH	Occupational safety and health

P

P&C	Protection and control
PAR	Progressive Aboriginal Relations
PBR	Performance based regulation
PCB	Polychlorinated biphenyl
PEM	Pemberton Substation
PIM	Performance incenting mechanism
PLC	Power Line Carrier
PMAES	Personnel, materials and external services
PMI	Project Management Institute

PPM	Project and Portfolio Management
PRES	Peace River Electricity Supply Project
Previous Application	BC Hydro's Fiscal 2017 - Fiscal 2019 Revenue Requirements Application
PSSP	Power system safety protection
PTP	Point-to-Point

R

RAS	Remedial action scheme
Resource Loaded Schedule	The project schedule with resources included, which forms the basis of the project cost estimate.
Revised Proposal	BC Hydro's submission in the BCUC's Review of the Regulatory Oversight of Capital Expenditures and Projects
RIB	Residential Inclining Block. The rate class for residential customers.
ROW	Right(s)-of-way
RRA	Revenue Requirement Application
RSRA	Rate-Smoothing Regulatory Account

S

SAE	Statistically Adjusted End-Use Model
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SARI	System Average Reliability Index
SBK	Southbank Substation
SCADA RTU	Supervisory control and data acquisition remote terminal unit.
SDA	Substation distribution assets
SEC	Securities and Exchange Commission (U.S.)
SEM	Strategic Energy Management

SERA	Skumatz Economic Research Associates
SFN	Stave Falls Generating Station
SGB	Shell Groundbirch Substation
SMI	Smart Metering and Infrastructure
SMW	Sumas Way Substation
SOO	Statement of objectives
SOP	Standing Offer Program
SQH	Squamish Substation
STR	Strathcona Dam

T

T&D	Transmission & Distribution
Test Period	The fiscal 2020 to fiscal 2021 period
TIDA	Trade-Income Deferral Account
TML	Teck Metals Ltd.
TMP	Thermo-Mechanical Pulping Program
TPA	Transfer Pricing Agreement
TRC	Total Resource Cost
TRR	Transmission Revenue Requirement
TSE	Truck stop electrification
TSR	Transmission Service Rate, applies to large industrial customers supplied with electricity at transmission voltage (60,000 volts or more)

U

UC	Utility Cost
UCA	*Utilities Commission Act*
UCT	Utility Cost Test
UFM	Utility Fleet Mechanic
UHF	Ultra-high frequency

UNDRIP	United Nations Declarations on the Rights of Indigenous Peoples
USMCA	United States Mexico Canada Agreement
USoA	Uniform System of Accounts

V

VAR	Volt-ampere reactive
VHF	Very high frequency
VVO	Volt var optimization

W

Waneta 2017 Transaction	BC Hydro's purchase of the remaining two-thirds interest in the Waneta Dam from Teck Metals Ltd.
WBK	Westbank Substation
WECC	Western Electricity Coordinating Council
Work Package	A document that clearly identifies a practice area's responsibilities in a project, including scope, schedule, cost and accountabilities.
WPP	Work Protection Practices
WUP	Water Use Plan

Z

Zone II	Zone II Ratepayers Group