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September 3, 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: Project No. 1598990
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2020 to Fiscal 2021 Revenue Requirements Application
Responses to Round 2 Information Requests

BC Hydro writes in compliance with BCUC Order No. G-146-19 to provide its responses to Round 2 information requests as follows:

Exhibit B-12	Responses to BCUC IRs (Public Version)
Exhibit B-12-1	Responses to BCUC IRs (Confidential Version)
Exhibit B-13	Responses to Interveners IRs (Public Version)
Exhibit B-13-1	Responses to Interveners IRs (Confidential Version)

BC Hydro is filing a limited number of responses and/or attachments to responses confidentially with the BCUC, pursuant to section 42 of the *Administrative Tribunals Act* and Part 4 of the Commission's Rules of Practice and Procedure. We have limited the redactions to the greatest extent possible. In each instance where a redaction was necessary, we have provided an explanation for the request for confidential treatment in the public version of the IR response.

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/rh

Enclosure

23.0 Load and Revenue Forecasts

Reference: Exhibit B-5, BC Hydro Response to BCUC IR 1.5.1, pdf p. 47

In its response, BC Hydro states (emphasis added):

> The difference in the average growth between the October 2018 Load Forecast and the May 2016 Load Forecast is a result of differences in drivers, assumptions, and methodology. All of these impact the difference between the two forecasts as shown in the table below and their respective growth rates as shown in the figure below.

It is not clear from BC Hydro's Application what the statistical confidence level is for its Monte Carlo uncertainty model, used to develop its load forecast. It is also unclear whether the changes in the load forecasting methodology from May 2016 to October 2018 includes changes to BC Hydro's probability approach. AMPC is therefore seeking further clarification on the probability approach and methodology used by BC Hydro for its load and revenue forecasts.

2.23.1 Are the load and revenue forecasts in this Application based on a P50 probability approach (i.e., where 50% of estimates exceed the P50 estimate and 50% fall below the P50 estimate)? Is the P50 probability approach used for all customer classes? Please fully explain your response.

RESPONSE:

For this response BC Hydro is defining a P50 probability approach as one which uses probabilistic Monte Carlo simulation that considers uncertainty in all the load drivers including Demand-Side Management (DSM) savings to derive P50 forecasts on an after DSM saving basis and statistical confidence level estimates to these P50 estimates.

The mid load forecasts and revenue forecasts for the main customer sectors contained in the Application are not based on a P50 probability approach as defined above. Each customer sector mid forecast is developed using the step-by- step process described below. This process includes projections derived from deterministic (i.e., not probability-based simulations) forecasting models (for the residential, commercial, and portions of the light industrial forecasts) and customer-based forecasts with probability weightings (for the large industrial and portions of the light industrial sector forecasts).

For the total system mid load forecasts, only the low and high uncertainty bands around that forecast are developed using Monte Carlo model simulations with the uncertainty in load drivers, excluding DSM savings.

The mid forecasts for each sector are developed in accordance with the methodology, assumptions and load drivers as described in Chapter 3 and Appendix O of the Application. The forecasts for each sector are developed in four steps, which are summarized below. The forecasts from the last step are the (mid) forecast after adjusting for loss reductions and DSM savings. These forecasts represent BC Hydro's expected load outcome and are the basis for the revenue projections in the Application.

The steps to derive the sector forecasts are as follows:

1. **Develop a (mid) billed sales forecast before rate impacts with the forecasting models (residential, commercial, a portion of light industrial sector) and customer based load forecasts (large industrial and some sub-sectors within the light industrial sectors). This step also includes adjustments to model projections, such as including the impacts of emerging new loads (e.g., cannabis, cryptocurrency and electric vehicles);**
2. **Develop a (mid) billed sales forecast after rate impacts with the price elasticity assumption of - 0.1 and the forecast of bill impacts;**
3. **Develop a (mid) billed sales forecast after load reductions for loss reduction savings and DSM savings; and**
4. **Develop a (mid) accrued sales forecast after loss reduction savings and DSM savings for the purpose of forecasting revenues.**

The mid sector forecasts from step 4 are summarized in Table 3-3 of the Application, while the mid billed sales forecasts, after DSM savings, from step 3 are summarized in the table in the Executive Summary on page 3 of Appendix O of the Application. The difference between billed and accrued sales is described in section 2.2.3 of Appendix O.

To complete the development of BC Hydro's October 2018 Load Forecast, a series of high and low forecasts were developed with BC Hydro's Monte Carlo simulation model. These forecasts include:

- **A high and low forecast of total gross requirements after rate impacts, before DSM as shown in Table 11-4 of Appendix O;**
- **A high and low forecast of total firm sales after rate impacts, before DSM as shown in Table 11-5 of Appendix O;**

- **A high and low forecast of total Domestic Sales after loss reductions and DSM savings as shown in Table 11-6 of Appendix O; and**
- **A high and low forecast of total Domestic sales after loss reductions and DSM saving on an accrued sales basis as shown in Table 3-3 of the Application.**

The high and low total Domestic sales forecasts, as shown in Table 3-3 of the Application are the results of the Monte Carlo simulation, and subsequent processing of the results. The steps used to develop the high and low forecasts are as follows:

1. **The Monte Carlo simulation model is used to develop the high and low total firm billed sales forecasts after rate impacts. The high and low forecasts represent an 80 per cent confidence interval for mid forecasts after rate impacts;**
2. **The high and low total Domestic billed sales forecast are determined by adjusting for loss reductions and DSM savings and removing BC Hydro's Own Use electricity consumption, and**
3. **The ratios of billed to accrued Domestic sales are used to determine the high and low domestic sales forecasts after loss reductions and DSM savings, as shown in Table 3-3 of the Application.**

In summary, mid sector forecasts used for the basis of revenues in the Application are not P50 probability based forecasts determined from Monte Carlo simulations. The mid forecasts are derived from deterministic approaches and the step by step forecasting process outlined above. Furthermore, the high and low forecasts after DSM savings as shown in Table 3-3 of the Application are not confidence interval based forecasts for the mid forecasts. These are the result of post-processing the high and low forecasts from the Monte Carlo simulations as described above.

BC Hydro wishes to clarify that the high and low total domestic billed sales forecasts after DSM, as published in Table 11-6 of Appendix O of the Application are not correct. These forecasts do not reconcile with the high and low total domestic billed sales forecasts shown in the table in the Executive Summary on page 3 of Appendix O. The corrected information for Table 11-6 of Appendix O is shown in the table below.

Mid, High and Low Total Domestic Sales after Loss Reductions and DSM Savings

	Low with DSM Total Domestic Sales (GWh)	Mid with DSM Total Domestic Sales (GWh)	High with DSM Total Domestic Sales (GWh)	
F19	**51,754**	**52,643**	**53,546**	
F20	**52,239**	**53,561**	**54,901**	
F21	**51,365**	**53,253**	**55,190**	
F22	**50,836**	**53,090**	**55,399**	
F23	**50,674**	**53,434**	**56,279**	
F24	**51,252**	**54,552**	**57,952**	
Note:				
1. Forecasts for fiscal 2019 include actual sales for the first six months of F2019 and six months forecast.				

23.0 Load and Revenue Forecasts

Reference: Exhibit B-5, BC Hydro Response to BCUC IR 1.5.1, pdf p. 47

In its response, BC Hydro states (emphasis added):

The difference in the average growth between the October 2018 Load Forecast and the May 2016 Load Forecast is a result of differences in drivers, assumptions, and methodology. All of these impact the difference between the two forecasts as shown in the table below and their respective growth rates as shown in the figure below.

It is not clear from BC Hydro's Application what the statistical confidence level is for its Monte Carlo uncertainty model, used to develop its load forecast. It is also unclear whether the changes in the load forecasting methodology from May 2016 to October 2018 includes changes to BC Hydro's probability approach. AMPC is therefore seeking further clarification on the probability approach and methodology used by BC Hydro for its load and revenue forecasts.

2.23.2 If BC Hydro did not use a P50 probability approach for its load forecast in the current Application, please provide a table that outlines the financial impacts of using a P50 probability approach for load forecasting in terms of impacts to revenue requirement, forecast revenues, and resulting rate changes. The table should target the same level of return for the 2020 and 2021 test years (holding all else equal, i.e., not simply capturing differences in deferral accounts).

RESPONSE:

For this response BC Hydro is defining a P50 probability approach as one that uses probabilistic Monte Carlo simulation that considers uncertainty in all the load drivers, such as Demand-Side Management (DSM) savings, economic drivers, and an electric vehicles forecast to derive the P50 forecasts on an after DSM savings basis. As described in our response to AMPC IR 2.23.2, this approach is not the basis for developing our mid load forecast.

BC Hydro has estimated that it would take approximately five months of dedicated time to develop a P50 probability forecast for each of the main customer sectors (residential, commercial, light industrial and large industrial) that considers each sector's load drivers. Including all the load drivers would involve the development of multiple distributions that account for load increases and decreases that are reflected in BC Hydro's load forecast. For example, in the residential sector the load forecast is developed with a forecast of use per account, number of

accounts, electric vehicles, codes and standards estimates, fuel switching estimates, rate impacts, load reductions for DSM savings, and loss reduction savings. To do a P50 forecast for these sectors would require the development of distributions for all of above-mentioned elements as well as the underlying load drivers of use per account and accounts such as housing projections. There is insufficient time in this regulatory process to develop a P50 probability based load forecast that considers all these elements.

BC Hydro believes that its current methodology for forecasting load in order to estimate revenues is appropriate. BC Hydro's current methodology is consistent with utility best practices and with methodologies used by other BCUC-regulated utilities. For example:

- **The audit of BC Hydro's forecast that was carried out in fiscal 2018 found that BC Hydro's forecasting function compares favourably to industry standards and to other large electric utilities in North America, and that BC Hydro's load forecasting methodologies are consistent with best practices, and**
- **In light of the BCUC's observation on short term forecasting methods included in its Decision on the Previous Application, BC Hydro reviewed other utilities' short-term forecast methodologies. We found that other BCUC-regulated utilities, such as FortisBC Electric, do not develop P50 probability forecasts for the purpose of establishing forecasts for revenue requirements and rates.**

BC Hydro's Monte-Carlo model used for the purpose of developing high and low uncertainty bands was reviewed by a third party expert (DNV GL) and was found to be sound as a method to develop a range of uncertainty in the load forecast. For further information on this please see Appendix Q of the Application.

23.0 Load and Revenue Forecasts

Reference: Exhibit B-5, BC Hydro Response to BCUC IR 1.5.1, pdf p. 47

In its response, BC Hydro states (emphasis added):

The difference in the average growth between the October 2018 Load Forecast and the May 2016 Load Forecast is a result of differences in drivers, assumptions, and methodology. All of these impact the difference between the two forecasts as shown in the table below and their respective growth rates as shown in the figure below.

It is not clear from BC Hydro's Application what the statistical confidence level is for its Monte Carlo uncertainty model, used to develop its load forecast. It is also unclear whether the changes in the load forecasting methodology from May 2016 to October 2018 includes changes to BC Hydro's probability approach. AMPC is therefore seeking further clarification on the probability approach and methodology used by BC Hydro for its load and revenue forecasts.

2.23.3 Please confirm BC Hydro used the load forecast from its Application for its capital expenditure and planning in the test years. If not confirmed, please fully explain your response, including:

(a) Identifying the load forecast BC Hydro uses for planning replacement and growth-related capital expenditures and project timing;
(b) Discussing the differences between the load forecast filed in this Application and the load forecast(s) used for capital planning purposes; and
(c) Providing a table that compares the following by rate class: load forecast, a P50 probabilistic-based load forecast, and the load forecast used for planning capital expenditures.

RESPONSE:

Not confirmed. For capital planning, BC Hydro uses the peak demand forecast. The October 2018 Load Forecast included in the Application is an energy forecast. An updated peak demand forecast was not available at the time the fiscal 2020 to fiscal 2024 Capital Plan was being finalized.

In terms of the three issues raised in the question:

(a) In developing the Fiscal 2020 to Fiscal 2024 Capital Plan, BC Hydro used the following forecasts:

- **The May 2016 System Peak Demand Load Forecast for transmission system projects;**
- **The 2017 Substation Peak Demand Load Forecast for substation and distribution projects; and**
- **The May 2016 (August 2017 Review) System Peak Demand Load Forecast for generation.**

As the actual substation load (MVA) growth was moderating, BC Hydro reduced the overall growth related substation and distribution capital expenditures in the Fiscal 2020 to Fiscal 2024 Capital Plan, which formed the basis for the capital expenditures in the test period, as explained in section 6.3.2.1 of Chapter 6 of the Application.

(b) As explained above and in more detail in Chapter 3 of the Application, the October 2018 Load Forecast in the Application is an energy forecast (i.e., a forecast of electricity sales, in GWh, from fiscal 2019 to fiscal 2024). In contrast, the forecasts used for capital planning are forecasts of peak MVA demand.

(c) A table comparing the October 2018 Load Forecast in the Application, a P50 probabilistic based load forecast, and the load forecasts used for planning capital expenditures by rate class cannot be provided because:

- **As explained in (b) above, the October 2018 Load Forecast in the Application is an energy forecast while the forecasts used for capital planning are peak demand forecasts;**
- **The peak MVA demand forecasts used for capital planning are not developed on a rate class basis; and**
- **As explained in BC Hydro's response to AMPC IR 2.23.1, the mid load energy forecasts for the main customer sectors contained in the Application are not based on a P50 probability approach. Accordingly, the mid peak forecasts used for planning are also not P50 forecasts because the system mid peak forecast is developed from the mid load energy forecast.**

24.0 Load Forecast

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.2.2, pdf p. 4

In its response, BC Hydro states that "[it] did not observe a material impact on load due to the constrained gas supply [resulting from the October 2018 rupture of the Enbridge T-South pipeline] from October 2018 to April 2019".

Reference: FortisBC Inc., "BC's natural gas supply may be limited this winter, reducing your use will help" (attached as Appendix A)

In its news releases dated between October 8 to December 12, 2018, FortisBC Inc. issued multiple news releases asking customers to reduce natural gas use following the rupture of the Enbridge pipeline.

After the October 2018 rupture of the Enbridge T-South pipeline, many customers were required to switch fuels, or did so voluntarily, in response to the constrained gas supply and increased natural gas costs. AMPC is seeking additional information on how constrained gas supply and fuel switching impacted BC Hydro's load.

2.24.1 Please provide data for each month between October 2018 to April 2019 on the effect of constrained gas supply/fuel switching on BC Hydro's load.

RESPONSE:

BC Hydro cannot provide the data requested as this information is not tracked.

BC Hydro can provide the following table which provides the monthly variance in load between October 2018 and April 2019 for large industrial customers.

Load for large industrial customers is most likely to be effected by constrained gas supply as these customers can switch between gas and electricity (i.e., fuel switching) more easily.

F2019 Domestic Energy Sales (GWh)	Schedule Reference 14.0 L3+L9[1]	Schedule Reference 14.0 L3+L9		
	Large Industrial - RRA	Large Industrial - Actual	Variance	Variance %
Apr-2018	1,143	1,049	(94)	-8.2
May-2018	1,144	1,070	(73)	-6.4
Jun-2018	1,112	1,109	(2)	-0.2
July 2018	1,129	1,165	36	3.2
August 2018	1,158	1,196	39	3.4
September 2018	1,137	1,188	51	4.5
October 2018	1,175	1,185	10	0.8
November 2018	1,188	1,210	22	1.8
December 2018	1,199	1,226	27	2.3
January 2019	1,204	1,198	(5)	-0.5
February 2019	1,128	1,107	(21)	-1.9
March 2019	1,165	1,191	26	2.2
Total F2019	13,882	13,896	15	0.1

While BC Hydro cannot determine how much of the monthly variance in load is attributable to the rupture of the Enbridge T-South pipeline as customers are not required to notify BC Hydro why they increase or decrease their electricity consumption, the data does not indicate there was a material change to transmission load attributable to the rupture of the Enbridge T-South pipeline in October 2018.

[1] Please refer to Fiscal 2020 – Fiscal 2021 Revenue Requirements Application Evidentiary Update Appendix A Schedule 14 column 1 and 2

24.0 Load Forecast

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.2.2, pdf p. 4

In its response, BC Hydro states that "[it] did not observe a material impact on load due to the constrained gas supply [resulting from the October 2018 rupture of the Enbridge T-South pipeline] from October 2018 to April 2019".

Reference: FortisBC Inc., "BC's natural gas supply may be limited this winter, reducing your use will help" (attached as Appendix A)

In its news releases dated between October 8 to December 12, 2018, FortisBC Inc. issued multiple news releases asking customers to reduce natural gas use following the rupture of the Enbridge pipeline.

After the October 2018 rupture of the Enbridge T-South pipeline, many customers were required to switch fuels, or did so voluntarily, in response to the constrained gas supply and increased natural gas costs. AMPC is seeking additional information on how constrained gas supply and fuel switching impacted BC Hydro's load.

2.24.2 What threshold does BC Hydro use to determine whether an impact on load is "material"? Please fully explain your response.

RESPONSE:

BC Hydro does not have a specific threshold that it uses to determine whether an impact on load is material. In aggregate we track the variance of actuals against plan within ranges, recognising uncertainty. When changes from expected load are observed, BC Hydro works with large industrial customers to understand the reason for short and long term load variances.

Reviewing the data provided in BC Hydro's response to AMPC IR 2.24.1, BC Hydro observes the following:

- **From April 2018 to September 2018, the variances between actual and plan load from large industrial customers ranged from (8.2) per cent to 4.5 per cent;**
- **From October 2018 to March 2019, the variances between actual and plan load from large industrial customers ranged from (1.9) per cent to 2.3 per cent. The range of these load variances was less than the range of load variances prior to the constrained gas supply; and**

- **Actual load for industrial customers from October 2018 to March 2019 was only 58 GWh (0.8 per cent) higher than plan and within the range of variation observed through the year, thus the data does not indicate there was a material change in transmission load attributable to the rupture of the Enbridge T South pipeline.**

24.0 Load Forecast

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.2.2, pdf p. 4

In its response, BC Hydro states that "[it] did not observe a material impact on load due to the constrained gas supply [resulting from the October 2018 rupture of the Enbridge T-South pipeline] from October 2018 to April 2019".

Reference: FortisBC Inc., "BC's natural gas supply may be limited this winter, reducing your use will help" (attached as Appendix A)

In its news releases dated between October 8 to December 12, 2018, FortisBC Inc. issued multiple news releases asking customers to reduce natural gas use following the rupture of the Enbridge pipeline.

After the October 2018 rupture of the Enbridge T-South pipeline, many customers were required to switch fuels, or did so voluntarily, in response to the constrained gas supply and increased natural gas costs. AMPC is seeking additional information on how constrained gas supply and fuel switching impacted BC Hydro's load.

2.24.3 Please describe any effects to Powerex's trading activity, for gas or electricity, that were caused by the October 2018 rupture of the Enbridge T-South pipeline.

RESPONSE:

BC Hydro provided responses to the implications associated with the October 2018 rupture of the Enbridge T-South pipeline as part of BC Hydro's responses to BCUC IR 1.21.1, and in regard to the Letter Agreement between BC Hydro and Powerex – Forward Electricity Purchases filing, which is publicly available at the following link:

https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-filings/fep/00-2019-05-23-bchydro-bcuc-wm.pdf

Details of Powerex Corp's business activities, unless otherwise publicly reported, are commercially sensitive and thus confidential.

24.0 Load Forecast

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.2.2, pdf p. 4

In its response, BC Hydro states that "[it] did not observe a material impact on load due to the constrained gas supply [resulting from the October 2018 rupture of the Enbridge T-South pipeline] from October 2018 to April 2019".

Reference: FortisBC Inc., "BC's natural gas supply may be limited this winter, reducing your use will help" (attached as Appendix A)

In its news releases dated between October 8 to December 12, 2018, FortisBC Inc. issued multiple news releases asking customers to reduce natural gas use following the rupture of the Enbridge pipeline.

After the October 2018 rupture of the Enbridge T-South pipeline, many customers were required to switch fuels, or did so voluntarily, in response to the constrained gas supply and increased natural gas costs. AMPC is seeking additional information on how constrained gas supply and fuel switching impacted BC Hydro's load.

2.24.4 Please describe any effects from the rupture and/or Powerex’s trading activity on BC Hydro’s system, e.g., depleted reservoir levels, that extended beyond April 2019.

RESPONSE:

There are numerous factors that impact BC Hydro system conditions (including reservoir levels). BC Hydro cannot generally isolate the impact of each of the various factors on the BC Hydro system. However, BC Hydro was limited in its ability to run Island Generaton during the winter 2018/19 period as a direct impact of the pipeline rupture and ongoing derate.

BC Hydro notes that the Enbridge T-South pipeline continues to be derated while work continues to satisfy National Energy Board requirements arising from the rupture. BC Hydro does not have information on when this de-rate will end. However, over the past number of months BC Hydro has been able to nominate gas to the Island Generation when economic to do so.

Please also refer to BC Hydro’s response to AMPC IR 2.24.3 for a link to the Letter Agreement between BC Hydro and Powerex – Forward Electricity Purchases Filing.

25.0 Finance Charges

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.4.2 and Attachment 1, pdf pp. 45-48

In its response, BC Hydro provides a table that shows its sinking fund balances, sinking fund income and sinking fund income as a percentage of total sinking fund balances for each year from F2016 to F2021. The table shows mid-year net debt of $22,994 million and $24,212 million for 2020 and 2021, which is higher compared to the mid-year rate base of $22,759 million and $23,162 million.

AMPC is seeking clarification on the figures provided by BC Hydro.

2.25.1 Could any portion of the $1,500 million and $2,300 million of new borrowing for 2020 and 2021 be borrowed as short-term debt? Please fully explain your response and provide any relevant supporting documents or policies.

RESPONSE:

BC Hydro takes a fiscally prudent approach to managing its debt portfolio in a manner appropriate for a Crown Corporation and for the long-term benefit of the shareholder and ratepayers. At the same time, BC Hydro mitigates the risks to finance charges associated with fluctuations primarily in interest rates.

BC Hydro has a debt management strategy that it believes is in the best interest of ratepayers. This includes a limit for the amount of variable rate debt, which is the type of debt that short-term borrowings are part of. In addition, short-term borrowings are limited under a Government of B.C. policy to up to a maximum of $4.5 billion Canadian (please refer to Attachment 1 to this response).

Our view is that from an overall perspective, debt should be issued to be aligned with the purpose of the expenditures it is drawn for. In our case, the bulk of our debt is used for capital expenditures. BC Hydro's capital assets are long-term in nature. It is prudent to generally match the term of our debt with our capital asset base as recovery of the cost of the assets is used to pay down debt and interest. In addition, we believe fixed rate debt helps us better manage total costs for ratepayers by providing stability in costs and ensuring when budgeting, that finance charges are managed against budget.

BC Hydro's strategic management of its debt portfolio, including effective and appropriate debt issuance, is evidenced by both BC Hydro and the Government of B.C.'s senior unsecured credit ratings of triple-A, the highest ratings available, by

Standard and Poor's and Moody's. As a result of these high credit ratings, BC Hydro has access to funds at favourable borrowing rates.

Attachment 2 to this response provides the Board-approved Treasury Risk Management Policy that applies to BC Hydro's management of its debt.

The public version of Attachment 2 to this response has BC Hydro's Board Approved Financial Institutions and Insurance Credit Limits included in Tables 3, 4 and 5 redacted to maintain confidentiality over commercially sensitive information. Publication of this information could harm BC Hydro's financial interests in dealings with financial institutions and insurance providers. The un-redacted version of Attachment 2 to this response is being provided to the BCUC in confidence to protect BC Hydro's financial interests.

Attachment 3 to this response provides the F2020 Liability Risk Management Annual Strategic Plan that details BC Hydro's current debt management strategy.

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

REQUEST TO THE MINISTER OF FINANCE TO INCREASE SHORT-TERM BORROWING LIMIT

Pursuant to section 54(1) of the *Financial Administration Act*, British Columbia Hydro and Power Authority ("BC Hydro") requests that the Minister of Finance approve increases to the borrowing limit applicable to BC Hydro's existing short term borrowing facility governed by the Short-Term Financing Agreement dated January 8, 2003 (the "Agreement") between BC Hydro and Her Majesty the Queen in right of the Province of British Columbia, represented by the Minister of Finance (the "Province") so the limit will be as follows:

(a) from April 1, 2012 until April 1, 2013, the maximum principal amount that may be outstanding under the Agreement at any particular time will be **$4,000,000,000** in Canadian currency or its equivalent in U.S. currency as calculated in accordance with section 6 of Order in Council 296/2004; and

(b) on and after April 1, 2013, the maximum principal amount that may be outstanding under the Agreement at any particular time will be **$4,500,000,000** in Canadian currency or its equivalent in U.S. currency as calculated in accordance with section 6 of Order in Council 296/2004.

For greater certainly, each such limit will, during its specified time-period, be in replacement of, and not in addition to, the maximum principal amount that may be outstanding under the Agreement as approved on behalf of the Minister of Finance in relation to any previous period.

BC Hydro hereby certifies that this request has been duly authorized, executed and delivered and that this request, and any borrowing in accordance with it, does not conflict with, nor will they result in a breach of, any resolutions, regulations, authorities, or authorizations applicable to BC Hydro. BC Hydro agrees to immediately notify the Province in writing if any resolutions, authorities or authorizations applicable to BC Hydro are rescinded, amended or otherwise become unavailable such that borrowings by the BC Hydro in accordance with this request may no longer be authorized.

This request is made on behalf of British Columbia Hydro and Power Authority by:

Name: James Le Lievre
Title: Treasurer

Date: March 8th, 2012

CERTIFICATE

Date: March 15, 2012

The terms of the above request made on behalf of BC Hydro by James Le Lievre, whom I consider authorized to make such request, meet with my satisfaction and are approved.

Peter Milburn
Deputy Minister of Finance

TREASURY RISK MANAGEMENT POLICY (TRMP)

Issue Date:

Revision 2: December 2017

Executive Sponsor

Chief Financial Officer (CFO), Cheryl Yaremko

Contact for Policy Interpretation and Clarification

Treasurer, Marisa Sawyer

GOVERNING ACTS

The Hydro and Power Authority Act (1996)

Financial Administrations Act (1996)

POLICY

The purpose of this Policy is to govern the overall financial risk associated with Treasury practices related to liability risk management, foreign exchange (FX) risk management, and financial institution (FI) credit risk management.

A conservative risk philosophy is applied that is appropriate for a high profile Crown Corporation within British Columbia. This philosophy is used to manage BC Hydro's liability portfolio in a fiscally prudent manner for the long-term benefit of the shareholder and ratepayer, while mitigating the risks to finance charges associated with adverse fluctuations in interest and foreign exchange rates.

The following Board approved Treasury policies must be complied with:

- For liability risk management as outlined in **Appendix 1: Table 1**:
  - variable rate debt is managed within +/-10% of the variable rate debt benchmark as a percentage of total net debt;
  - net foreign debt is limited to 5% of total net debt; and
  - only approved Treasury risk management products are used to manage financial risks.
- For foreign exchange risk management as outlined in **Appendix 1: Table 2**:
  - FX exposure is managed within a limit of +/- US$100M (FX Risk Limit).
- For credit risk management:
  - FI credit exposures are managed within enterprise-wide FIs credit limits, settlement limits, tenor limits, and, coverage limits (applicable to insurance companies) (Collectively

called the FI Credit and Insurance Limits) as outlined in **Appendix I: Tables 3 and 4** and in the corporate level Financial Institutions Credit Risk Management Procedures (FICRMP) approved by the CFO; and

- discretionary credit approval authorities given to the CFO to increase FI Credit Limits for an individual FI are within the FI Discretionary Credit Approval Authorities as outlined in **Appendix 1: Table 5**.

(Collectively called the Board Approved Treasury Limits)

The following CFO approved Treasury limits must be complied with:

- all risk exposure strategies and limits established in the Liability Risk Management Annual Strategic Plan (Annual Strategic Plan) with a copy to the Audit and Finance Committee (AFC) at the next meeting following approval;
- liability risk management transactions are executed by authorized traders and within approved trading limits as approved by the CFO and as outlined in the corporate level, Liability Risk Management Procedures (LRMP); and
- FX risk management transactions are executed by authorized traders and within approved trading limits as approved by the CFO and as outlined in the corporate level Foreign Exchange Risk Management Procedures (FXRMP).

(Collectively called the CFO Approved Treasury Limits)

The following Government requirements must be complied with:

- commercial paper issuances cannot exceed the $4.5 billion Canadian limit established by the Government in accordance with section 6 of Order in Council 296/2004; and
- the applicable Financial Administration Act Treasury Board Regulation requiring that BC Hydro establishes and maintains a Risk Management Committee and a Risk Management Policy with respect to commodity derivatives.

SCOPE

This policy applies to employees responsible for all Treasury related transactions.

Exception

Powerex is governed by its own Board approved Powerex Risk Management Policy.

POLICY APPLICATION

- The approved Treasury risk management products outlined in **Appendix I: Table 1** are used to manage the financial risks associated with interest rate exposure, FX exposure, and related FI credit risk exposure.
- Proper internal controls exist for authorizations, delegation of authority, segregation of duties, and monitoring and reporting requirements.
- Treasury management is conducted on a portfolio basis and within the Board Approved Treasury Limits, CFO Approved Treasury Limits, and the commercial paper limit (Collectively called the TRMP Limits). This portfolio approach is used to manage:

  - the various financial market factors, such as short-term and long-term interest rates and FX rates, with underlying business variables (e.g. revenues, expenditures), and
  - to establish the recommended weightings of variable and fixed rate debt, and Canadian and foreign debt approved by the CFO in the Annual Strategic Plan.
- FI Credit Limits are applied to each FI and are based on the FI's creditworthiness.
- Hedging FX risk in capital projects requires authorization by the CFO due to complex accounting treatment.
- Treasury's debt management strategy is reviewed annually and any updates to the strategy are referenced in the Annual Strategic Plan.
- Compliance with the TRMP Limits is monitored and reported monthly, independent of Treasury. Any non-compliance, as well as actions taken to address the non-compliance, is immediately reported to the CFO and then the AFC at their next meeting.
- The TRMP is reviewed on an annual basis by the CFO and is revised, if necessary, to reflect changes in underlying risks, business conditions, or other related policies, with any significant changes brought forward to the AFC for approval.

DELEGATION

The Board has overall responsibility for the TRMP and has delegated this responsibility to the AFC, including authority for reviewing and approving significant changes in the TRMP.

The AFC has delegated authority for the overall financial risk and Treasury management practices to the CFO. The Board has also given to the CFO discretionary authority to increase FI Credit Limits for an individual FI as outlined in **Appendix 1: Table 5**.

The CFO has the authority to further delegate responsibilities relating to the TRMP; however, further delegation by those receiving such delegation, except on a temporary basis, is not permitted.

The CFO has delegated to the Controller and the Treasurer oversight of the TRMP and the supporting corporate level LRMP, FXRMP, and FICRMP.

AUDIT AND FINANCE COMMITTEE (AFC) RESPONSIBILITIES

- Understanding the financial risks taken by BC Hydro and ensuring these risks are appropriately managed.
- Approving any significant changes to the TRMP, including changes to the Board Approved Treasury Limits, and the granting of temporary exemption from the Board Approved Treasury Limits under special circumstances.
- Reviewing the Annual Strategic Plan approved by the CFO.
- Reviewing the quarterly report for AFC prepared by Treasury (Quarterly AFC Treasury

Report).

- Reviewing non-compliance with TRMP Limits and any actions, including the use of the CFO's discretionary credit approval authority, taken to address the non-compliance.

ROLES AND RESPONSIBILITIES

	Treasurer	Controller	CFO	AFC[1]
Treasury Risk Management Policy (TRMP)	Directs	Reviews	Reviews	Approves
Liability Risk Management Annual Strategic Plan	Directs	Reviews	Approves	Reviews
Minor and administration changes to the Treasury Risk Management Policy	Recommends	Reviews	Approves	N/A
Supporting Documentation to the Treasury Risk Management Policy	Directs	Reviews	Approves	N/A
Non-compliance with TRMP Limits	Reviews and recommends action	Reviews	Reviews and approves action	Reviews action

[1]At the next AFC meeting.

SUPPORTING DOCUMENTATION

Liability Risk Management Procedures (LRMP)

Foreign Exchange Risk Management Procedures (FXRMP)

Financial Institutions Credit Risk Management Procedures (FICRMP)

DEFINITIONS

Credit Exposure: The maximum financial loss to BC Hydro should a Counterparty fail to meet its obligations in accordance with contractual requirements.

Credit Limit: The established maximum dollar limit of aggregated credit exposure assigned to a Counterparty that BC Hydro determines it is willing accept in order to prudently meet its business objectives.

Credit Risk Management: The management of the risk of financial loss associated with a counterparty's financial inability or unwillingness to fulfill or perform its obligations in accordance with contractual requirements.

Creditworthiness: The measure of one's ability to meet debt obligations. This may be measured by having an acceptable credit rating, or being financially sound enough to justify the extension of credit, or meriting credit on the basis of such factors as earning power, previous record of debt repayment, financial capacity to meet current and future financial obligations and commitments, etc.

Derivatives: Financial contracts where the value is derived from the value of an underlying asset or index, such as interest rates or foreign exchange. The contracts include, but are not limited to, interest rate swaps, options or futures; foreign currency swaps, options or futures.

Financial Institution: Corporations which provide services as intermediaries of financial markets. Broadly speaking, these include 1) depository institutions such as banks and credit unions, 2) contractual institutions such as insurance companies and sureties (owned by a financial institution), and 3) investment institutions such as investment banks, underwriters.

Financial Risk: The risk of a financial loss associated with entering into financial agreements and transactions. Types of financial risk include interest rate risk, foreign exchange risk, and credit risk.

Foreign Exchange Risk Management: The management of the risk of financial loss associated with changes in the rate or price of foreign exchange relative to the Canadian dollar. For BC Hydro, this risk is primarily the US/Canadian exchange rate.

Interest Rate Risk: The risk that arises from the movement of interest rates and creates a risk to finance charges. It is attributed to the differences between the timing of rate changes and the timing of cash flows (re-pricing risk) as well as from changing rate relationships across a spectrum of maturities (yield curve risk).

Liability Risk Management: The management of the risk of financial loss associated with the use of liabilities by a company with the objective of controlling the effect of liabilities on its profitability. It also involves controlling the amount of risk undertaken.

Liability Risk Management Annual Strategic Plan: An annual strategy plan prepared by Treasury that outlines the management of financial risks and liabilities for the coming fiscal year and may include information regarding anticipated borrowing requirements, benchmark weighting of variable rate debt, target for weighted average remaining term to maturity, and an interest rate, foreign exchange and derivatives exposure management strategy for the fiscal year.

Net Debt: The sum of total long-term debt and total short-term debt, less related sinking funds and other related investments such as commercial paper or bonds, and adjusted for any documented related currency conversion agreement by which the principal has been converted into Canadian currency.

Net Foreign Debt: The sum of total long-term debt and total short-term debt with principal not denominated in Canadian currency and not adjusted by a documented related currency conversion agreement by which the principal has been converted into Canadian currency, plus Canadian debt with principal converted into foreign debt through documented related currency conversion agreements, less related sinking fund and other related investments such as commercial paper or bonds not denominated in Canadian currency.

Quarterly AFC Treasury Report: Quarterly report prepared by Treasury for AFC that identifies and measures the following risks: (1) Credit Exposure; (2) Foreign Exchange Exposure; (3) Debt and Interest Rate Exposure, and provides updates on Pension and Insurance matters.

Settlement Limit: When there is an exchange of funds, the maximum dollar limit that BC Hydro can deliver to a counterparty without first receiving funds owing from the counterparty.

Tenor: The duration of a transaction that BC Hydro is authorized to conduct with a counterparty based on the counterparty's credit rating.

Variable Rate Debt: The total value of all financial obligations (long-term debt, short-term debt or other borrowing arrangements entered into for the purpose of the financing or conversion of existing borrowing arrangements) subject to interest rate reset uncertainty or principal repayment within a period of less than one year. The financial obligation is net of related sinking funds and related investments, and adjusted for any documented related interest rate and currency conversion agreements.

Variable Rate Debt Benchmark: The recommended weighting of variable rate debt as a percentage of net debt used to manage interest rate risk.

Weighted Average Remaining Term to Maturity: The weighted average amount of time until the total debt portfolio matures.

APPENDIX I

Table 1: Board Approved Liability Risk Management Items

Variable Rate Debt range	+/- 10% from the variable rate debt benchmark established in the Liability Risk Management Annual Strategic Plan
Net Foreign Debt	Not to exceed 5% of net debt
Approved Treasury Risk Management Products	• Commercial Paper • Bonds • Debentures • Interest rate swaps • Interest rate options • Interest rate futures • Bond Locks (also known as Bond Forwards) • FX Spots • FX Forwards • FX Swaps • FX Options • FX Futures • Cross Currency Swaps • Commodity Derivatives

Table 2: Board Approved Foreign Exchange Risk Limit

FX Risk Limit ($US Millions)	Timeframe	Items included in the FX Risk Limit	Items excluded from the FX Risk Limit
Managed within a limit of +/- $100	• ≤ 24 months • > 24 months requires CFO approval	• Existing US$ bank balances and temporary investments • Existing US$ FX derivative contracts maturing with 24 month • Existing US$ debt obligations maturing within 24 months • Known US$ expenditures or revenues captured in operational activity within 24 months	• Capital expenditures procured in a foreign currency or that have a variable price that is tied to changes in exchange rates. • Any US$ derivative contracts, US$ debt obligations and known US$ expenditures or revenues occurring beyond 24 months.

Table 3: Board Approved Financial Institutions Credit Limits

External Credit Rating[1] (Standard and Poor's/Moody's Equivalent)	Internal Credit Rating	Maximum Credit Limit[2] is the Lesser of 1) Below Credit Limit ($ Millions) or 2) [redacted]% of FI's Tangible Net Worth	Maximum Tenor (Years)	Maximum Daily Settlement Limit ($ Millions)
AAA-/Aaa3 and above	3A- and above	[redacted]	[redacted]	[redacted]
AA+/Aa1	2A+	[redacted]	[redacted]	[redacted]
AA/Aa2	2A	[redacted]	[redacted]	[redacted]
AA-/Aa3	2A-	[redacted]	[redacted]	[redacted]
A+/A1	1A+	[redacted]	[redacted]	[redacted]
A/A2	1A	[redacted]	[redacted]	[redacted]
A-/A3	1A-	[redacted]	[redacted]	[redacted]
BBB+/Baa1	3B+	[redacted]	[redacted]	[redacted]
Below BBB+/Baa1	Below 3B+	In accordance with existing Board approved policies or Board approved exceptions, if applicable.		

[1] In the event of a split rating the lowest credit rating applies.
[2] BC Hydro's main cash management bank is allowed up to an additional $[redacted] of credit limit to cover large cash balances held for cash management purposes e.g. debt and liability payments, foreign exchange payments, large vendor payments, and payments to shareholder, yet overall credit limit is still subject to the lesser of [redacted]% of tangible net worth (tangible assets – liabilities).

Table 4: Board Approved Insurance Credit Limits

External Credit Rating[1] (Standard and Poor's/Moody's Equivalent)	Internal Credit Rating	AM Best Financial Strength Rating	Maximum Insurance Company Coverage Limit[2] ($ Millions)
AAA-/Aaa3 and above	3A- and above	A++,A+	[redacted]
AA-/Aa3 and above	2A- and above	A,A-	[redacted]
A-/A3 and above	1A- and above	B++,B+	[redacted]

[1] In the event of a split rating the lowest credit rating applies.
[2] Coverage limits are applicable to insurance companies underwriting 1) the catastrophic and executive liability insurance programs and 2) a construction insurance program for a major construction project over $[redacted], yet amounts under the two categories are not aggregated.

Table 5: Board Approved Discretionary Financial Institutions Credit Approval Authority

	Additional FI Credit Limit ($ Millions)	Additional Tenor Limit	Additional FI Settlement Limit ($ Millions)	Additional Insurance Coverage Limit
CFO	[redacted]	[redacted]	[redacted]	[redacted]

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F2020 Liability Risk Management Annual Strategic Plan

Executive summary

To outline BC Hydro's debt management strategy for F2020, which is consistent with the Amended F2019 Liability Risk Management Annual Strategic Plan.

F2020 Liability Risk Management Strategy:

1. **Variable Rate Debt:** BC Hydro's benchmark variable rate debt target remains unchanged at 15%. BC Hydro's Board-approved Treasury Risk Management Policy allows variable rate debt to be managed within +/- 10% of the variable rate debt benchmark and therefore BC Hydro's variable rate debt range is 5% - 25%.

2. **Debt:** Treasury is planning on issuing $1.5 billion of long-term debt in F2020 of which $1.025 billion is hedged. The forecast long-term debt issues will replace $0.2 billion of maturing long-term debt and reduce forecast commercial paper balances by approximately $0.1 billion. As a result, net debt is forecast to increase by $1.2 billion in F2020 (i.e. $1.5 billion new long-term debt issuance less $0.2 billion of maturing long-term debt less approximately $0.1 billion of commercial paper balance). Commercial paper month-end balances, estimated to average $3.0 billion over F2020, will continue to be managed within the facility limit of $4.5 billion and the variable rate debt limits. Commercial paper balance outstanding as at December 31, 2018 was $3.1 billion.

   Treasury will continue to target longer term debt issues of 10 years or greater with a weighted average term to maturity range of 10-20 years to align with the longer life of BC Hydro's capital assets. The weighted average term to maturity on a portfolio basis is forecast to be 14.6 years at March 31, 2019 and 14.0 years as at March 31, 2020.

3. **Foreign Denominated Debt:** From time to time as market conditions present opportunities, the Province, on behalf of BC Hydro, issues foreign denominated debt and may swap the proceeds, coupons and principal into Canadian dollars ("hedged debt"). The reason for this is to access foreign pools of investment at interest rates below or equal to the cost of issuing debt in the domestic Canadian market.

   The Treasury Risk Management Policy limits unhedged foreign debt principal to less than 5% of total net debt. At the end of F2019 unhedged foreign debt principal is forecast to be less than 1% of total net debt. At March 31, 2019 BC Hydro is forecasting to have $800 million of USD denominated long-term debt of which 90% is hedged (net of sinking funds), and €402 million of Euro denominated debt of which 100% is hedged. BC Hydro has some unhedged USD denominated debt, as it is a natural offset to USD trade income. Treasury does not anticipate issuing any unhedged foreign denominated debt in F2020.

4. **Use of Derivatives:** Treasury will continue to enter into currency derivatives for cash management and debt hedging purposes within the foreign exchange risk exposure limit of +/- US$100 million within a 24 month period as outlined in the Treasury Risk Management Policy.

   Interest rate derivatives will continue to be used to hedge interest rate risk on forecast future debt issuances. In F2020, Treasury will hedge up to 75% of total borrowing requirements, consistent with the Amended F2019 Liability Risk Management Annual

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F2020 Liability Risk Management Annual Strategic Plan

Strategic Plan, and will hedge over the next five fiscal years (i.e. out to and including F2025). "Total borrowing requirements" in this context refers to the total of forecast future long-term debt (i.e. bond) issuances and net new commercial paper issuance. Treasury is forecasting a total borrowing requirement of $1.4 billion in F2020 (i.e. the net of $1.5 billion long-term debt issuance and approximate $0.1 billion commercial paper balance reduction), of which 75% has been hedged.

The table below shows the forecast outstanding interest rate hedges for future debt issuance at March 31, 2019:

INTEREST RATE HEDGES FOR FUTURE DEBT ISSUANCES (IN $ BILLIONS)

Hedges Issued F2017	$4.400
Hedges Issued F2018	2.275
Hedges Issued F2019	3.325
Total Interest Rate Hedges Issued	**$10.000**
Hedges Settled and Long-term Debt Issued F2017	(0.800)
Hedges Settled and Long-term Debt Issued F2018	(1.000)
Hedges Settled and Long-term Debt Issued F2019	(2.150)
Total Interest Rate Hedges Outstanding	**$6.050**

During F2020 interest rate hedges for future debt issuances of $1.025 billion will be settled alongside long-term debt issuances. These hedges are comprised of $700 million of 10-year and $325 million of 30-year hedges.

Approved by: Jacqueline Rawluk

Jacqueline Rawluk
Acting Treasurer

Date: Jan 30 2019.

David Wong
Chief Financial Officer

Date: Jan 30, 2019

25.0 Finance Charges

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.4.2 and Attachment 1, pdf pp. 45-48

In its response, BC Hydro provides a table that shows its sinking fund balances, sinking fund income and sinking fund income as a percentage of total sinking fund balances for each year from F2016 to F2021. The table shows mid-year net debt of $22,994 million and $24,212 million for 2020 and 2021, which is higher compared to the mid-year rate base of $22,759 million and $23,162 million.

AMPC is seeking clarification on the figures provided by BC Hydro.

2.25.2 For the net long-term debt for 2020 and 2021 shown in the table, please indicate how much is for financing of assets in service (i.e., assets used and useful in 2020 and 2021) compared to other purposes (e.g., capital projects in progress, working cash requirements).

RESPONSE:

BC Hydro's debt is managed on a portfolio basis, with overall company-wide requirements funded using a mix of short and long-term debt.

BC Hydro does not forecast using project-specific financing and does not specifically allocate increases in net debt to specific drivers of debt. Therefore, BC Hydro is unable to provide a breakdown of fiscal 2020 and fiscal 2021 debt by financing attributable to assets in service versus financing for other purposes.

26.0 Finance Charges

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.4.2.2 and Attachment 1, pdf pp. 45-48

In its response, BC Hydro provides a schedule showing the calculation of long-term debt costs. The table shows Future Debt Hedge interest rates, but excludes the impact of hedging gains and losses. BC Hydro explains that these gains and losses are recorded in the Debt Management Regulatory Account and amortized in accordance with BCUC Order No. G-42-16.

AMPC is seeking clarification of the data provided in the schedule in order to understand BC Hydro's calculation of long-term debt costs.

2.26.1 Please revise the table provided in response to AMPC IR 1.4.2.2 Attachment 1 to include long-term debt costs using those hedged interest rates provided in response to AMPC IR 1.4.9.

RESPONSE:

The financial information provided in this response has been updated based on the information included in BC Hydro’s Evidentiary Update.

The table provided in Attachment 1 to BC Hydro’s response to AMPC IR 1.4.2.2 has been updated based on the information included in BC Hydro’s Evidentiary Update and is provided as Attachment 1 to this response, with lines that have changed highlighted with grey shading.

Attachment 2 to this response is the same as Attachment 1 to this response except it has been revised to include hedged long-term interest rates consistent with the hedged long-term interest rates provided in BC Hydro’s response to AMPC IR 1.4.9. Lines that have changed from Attachment 1 to this response are highlighted with grey shading. While Attachment 2 has been revised as requested, its presentation is not in accordance with the provisions of the Debt Management Regulatory Account established under BCUC Order No. G-42-16 and further outlined in section 7.8.13 of Chapter 7 of the Application.

Association of Major Power Customers of BC Information Request No. 2.26.1 Dated August 1, 2019 - Attachment 1

Line	Existing CAD Bonds	Coupon Rate	Notional	Issue Date	Maturity Date	Interest Expense	
						Fiscal 2020	Fiscal 2021
1		5.30%	$ 175,000,000	03-May-04	17-Jun-19	$ 1,982,055	$ -
2		10.60%	$ 599,825,000	05-Sep-90	05-Sep-20	$ 63,581,450	$ 27,522,929
3		3.70%	$ 500,000,000	23-Aug-10	18-Dec-20	$ 18,500,000	$ 13,279,452
4		9.95%	$ 296,339,000	15-Apr-96	15-May-21	$ 29,485,731	$ 29,485,731
5		4.80%	$ 155,000,000	07-Jun-07	15-Jun-21	$ 7,440,000	$ 7,440,000
6		4.80%	$ 75,000,000	07-Jun-07	15-Jun-21	$ 3,600,000	$ 3,600,000
7		9.50%	$ 100,000,000	09-Jun-92	09-Jun-22	$ 9,500,000	$ 9,500,000
8		8.75%	$ 200,000,000	19-Aug-92	19-Aug-22	$ 17,500,000	$ 17,500,000
9		2.70%	$ 100,000,000	28-Sep-12	18-Dec-22	$ 2,700,000	$ 2,700,000
10		2.70%	$ 100,000,000	14-Jan-13	18-Dec-22	$ 2,700,000	$ 2,700,000
11		8.00%	$ 100,000,000	08-Sep-93	08-Sep-23	$ 8,000,000	$ 8,000,000
12		3.30%	$ 100,000,000	27-Aug-13	18-Dec-23	$ 3,300,000	$ 3,300,000
13		5.54%	$ 10,000,000	09-Aug-04	09-Aug-24	$ 554,000	$ 554,000
14		2.85%	$ 300,000,000	16-Jan-15	18-Jun-25	$ 8,550,000	$ 8,550,000
15		2.85%	$ 300,000,000	30-Jun-15	18-Jun-25	$ 8,550,000	$ 8,550,000
16		2.85%	$ 300,000,000	05-Nov-15	18-Jun-25	$ 8,550,000	$ 8,550,000
17		2.30%	$ 500,000,000	16-Mar-16	18-Jun-26	$ 11,500,000	$ 11,500,000
18		2.30%	$ 200,000,000	12-May-16	18-Jun-26	$ 4,600,000	$ 4,600,000
19		2.30%	$ 150,000,000	27-Jan-17	18-Jun-26	$ 3,450,000	$ 3,450,000
20		2.55%	$ 300,000,000	21-Mar-17	18-Jun-27	$ 7,650,000	$ 7,650,000
21		2.55%	$ 200,000,000	17-Oct-17	18-Jun-27	$ 5,100,000	$ 5,100,000
22		2.55%	$ 200,000,000	17-Oct-17	18-Jun-27	$ 5,100,000	$ 5,100,000
23		2.55%	$ 200,000,000	17-Oct-17	18-Jun-27	$ 5,100,000	$ 5,100,000
24		2.55%	$ 100,000,000	21-Jun-18	18-Jun-27	$ 2,550,000	$ 2,550,000
25		2.95%	$ 200,000,000	15-May-18	18-Dec-28	$ 5,900,000	$ 5,900,000
26		2.95%	$ 100,000,000	21-Jun-18	18-Dec-28	$ 2,950,000	$ 2,950,000
27		2.95%	$ 200,000,000	20-Jul-18	18-Dec-28	$ 5,900,000	$ 5,900,000
28		2.95%	$ 200,000,000	20-Jul-18	18-Dec-28	$ 5,900,000	$ 5,900,000
29		2.95%	$ 300,000,000	18-Sep-18	18-Dec-28	$ 8,850,000	$ 8,850,000
30		2.95%	$ 200,000,000	18-Sep-18	18-Dec-28	$ 5,900,000	$ 5,900,000
31		2.95%	$ 300,000,000	11-Jun-19	18-Dec-28	$ 7,128,493	$ 8,850,000
32		5.70%	$ 300,000,000	13-Jul-06	18-Jun-29	$ 17,100,000	$ 17,100,000
33		5.15%	$ 200,000,000	19-Jun-07	18-Jun-29	$ 10,300,000	$ 10,300,000
34		6.35%	$ 200,000,000	16-Jun-00	18-Jun-31	$ 12,700,000	$ 12,700,000
35		6.35%	$ 100,000,000	15-Nov-01	18-Jun-31	$ 6,350,000	$ 6,350,000
36		6.35%	$ 100,000,000	18-Dec-01	18-Jun-31	$ 6,350,000	$ 6,350,000
37		6.35%	$ 400,000,000	16-Sep-05	18-Jun-31	$ 25,400,000	$ 25,400,000
38		5.00%	$ 100,000,000	10-Apr-12	18-Jun-31	$ 5,000,000	$ 5,000,000
39		5.00%	$ 110,000,000	20-Apr-12	18-Jun-31	$ 5,500,000	$ 5,500,000
40		5.00%	$ 100,000,000	29-Oct-12	18-Jun-31	$ 5,000,000	$ 5,000,000
41		4.95%	$ 150,000,000	08-Dec-08	18-Jun-40	$ 7,425,000	$ 7,425,000
42		4.95%	$ 300,000,000	26-May-09	18-Jun-40	$ 14,850,000	$ 14,850,000
43		4.95%	$ 300,000,000	15-Jul-09	18-Jun-40	$ 14,850,000	$ 14,850,000
44		4.95%	$ 500,000,000	11-Jan-10	18-Jun-40	$ 24,750,000	$ 24,750,000
45		3.54%	$ 70,097,000	08-May-12	08-May-42	$ 2,481,434	$ 2,481,434
46		3.22%	$ 97,715,000	11-Jun-12	11-Jun-42	$ 3,146,423	$ 3,146,423
47		4.30%	$ 100,000,000	08-Sep-10	18-Jun-42	$ 4,300,000	$ 4,300,000
48		4.30%	$ 500,000,000	11-Apr-11	18-Jun-42	$ 21,500,000	$ 21,500,000
49		4.30%	$ 500,000,000	06-Jun-11	18-Jun-42	$ 21,500,000	$ 21,500,000
50		4.30%	$ 300,000,000	27-Oct-11	18-Jun-42	$ 12,900,000	$ 12,900,000
51		4.30%	$ 200,000,000	01-Jun-12	18-Jun-42	$ 8,600,000	$ 8,600,000
52		4.30%	$ 200,000,000	28-Sep-12	18-Jun-42	$ 8,600,000	$ 8,600,000
53		3.29%	$ 54,786,000	10-Jul-12	10-Jul-42	$ 1,802,459	$ 1,802,459
54		3.20%	$ 200,000,000	04-Dec-12	18-Jun-44	$ 6,400,000	$ 6,400,000
55		3.20%	$ 300,000,000	20-Jun-13	18-Jun-44	$ 9,600,000	$ 9,600,000
56		3.20%	$ 300,000,000	02-Aug-13	18-Jun-44	$ 9,600,000	$ 9,600,000
57		3.20%	$ 400,000,000	17-Sep-13	18-Jun-44	$ 12,800,000	$ 12,800,000
58		3.20%	$ 265,000,000	14-Apr-14	18-Jun-44	$ 8,480,000	$ 8,480,000
59		3.20%	$ 500,000,000	20-Jun-14	18-Jun-44	$ 16,000,000	$ 16,000,000
60		3.20%	$ 600,000,000	26-Sep-14	18-Jun-44	$ 19,200,000	$ 19,200,000
61		4.90%	$ 200,000,000	29-Jun-07	18-Jun-48	$ 9,800,000	$ 9,800,000
62		4.90%	$ 170,000,000	19-May-09	18-Jun-48	$ 8,330,000	$ 8,330,000
63		4.90%	$ 50,000,000	30-Sep-11	18-Jun-48	$ 2,450,000	$ 2,450,000
64		2.80%	$ 400,000,000	01-May-15	18-Jun-48	$ 11,200,000	$ 11,200,000
65		2.80%	$ 200,000,000	02-Jun-15	18-Jun-48	$ 5,600,000	$ 5,600,000
66		2.80%	$ 300,000,000	08-Sep-15	18-Jun-48	$ 8,400,000	$ 8,400,000
67		2.80%	$ 300,000,000	18-Jan-16	18-Jun-48	$ 8,400,000	$ 8,400,000
68		2.80%	$ 300,000,000	23-Sep-16	18-Jun-48	$ 8,400,000	$ 8,400,000
69		2.80%	$ 200,000,000	25-Nov-16	18-Jun-48	$ 5,600,000	$ 5,600,000
70		2.80%	$ 200,000,000	21-Jun-17	18-Jun-48	$ 5,600,000	$ 5,600,000
71		2.80%	$ 100,000,000	21-Jun-17	18-Jun-48	$ 2,800,000	$ 2,800,000
72		2.80%	$ 100,000,000	26-Sep-17	18-Jun-48	$ 2,800,000	$ 2,800,000
73		2.80%	$ 200,000,000	26-Sep-17	18-Jun-48	$ 5,600,000	$ 5,600,000
74		2.80%	$ 200,000,000	16-Apr-18	18-Jun-48	$ 5,600,000	$ 5,600,000
75		2.80%	$ 300,000,000	16-Apr-18	18-Jun-48	$ 8,400,000	$ 8,400,000
76		2.80%	$ 200,000,000	20-Jul-18	18-Jun-48	$ 5,600,000	$ 5,600,000
77		2.80%	$ 150,000,000	24-Jun-19	18-Jun-48	$ 3,233,425	$ 4,200,000

Line	Existing CAD Bonds	Coupon Rate	Notional	Issue Date	Maturity Date	Interest Expense Fiscal 2020	Interest Expense Fiscal 2021
78		2.95%	$ 100,000,000	24-Aug-18	18-Jun-50	$ 2,950,000	$ 2,950,000
79		2.95%	$ 100,000,000	24-Aug-18	18-Jun-50	$ 2,950,000	$ 2,950,000
80		2.95%	$ 250,000,000	24-Aug-18	18-Jun-50	$ 7,375,000	$ 7,375,000
81		2.95%	$ 50,000,000	07-Jun-19	18-Jun-50	$ 1,204,247	$ 1,475,000
82		2.95%	$ 50,000,000	07-Jun-19	18-Jun-50	$ 1,204,247	$ 1,475,000
83		3.50%	$ 60,000,000	30-Jan-13	18-Jun-55	$ 2,100,000	$ 2,100,000
84		3.30%	$ 50,000,000	27-May-13	18-Jun-62	$ 1,650,000	$ 1,650,000
85	**1) Total Existing CAD Bonds**		**$ 18,438,762,000**			**$ 731,803,962**	**$ 691,772,428**

Line	Existing Euro Bonds (coupons fully hedged to CAD)	Coupon Rate (CAD Swap Rate)	Notional (in CAD)	Issue Date	Maturity Date	Fiscal 2020	Fiscal 2021
86		2.46%	$ 390,750,000	08-Oct-15	08-Oct-25	$ 9,607,370	$ 9,607,370
87		2.39%	$ 200,000,000	20-Jul-16	20-Jul-32	$ 4,772,000	$ 4,772,000
88	**2) Total Existing EUR Bonds in CAD**		**$ 590,750,000**			**$ 14,379,370**	**$ 14,379,370**

Line	Existing USD$ Bonds (coupons not hedged to CAD)	Coupon Rate	Notional (in USD)	Issue Date	Maturity Date	Fiscal 2020	Fiscal 2021
89		6.50%	$ 500,000,000	24-Jan-96	15-Jan-26	$ 32,500,000	$ 32,500,000
90		7.25%	$ 300,000,000	29-Aug-96	01-Sep-36	$ 21,750,000	$ 21,750,000
91	**3) Total Existing USD Bonds in USD**		**$ 800,000,000**			**$ 54,250,000**	**$ 54,250,000**

Line	Existing USD Bonds - Foreign Exchange	Fiscal 2020	Fiscal 2021
92	**4) Foreign Exchange on Existing USD Bonds**	**$ 16,974,829**	**$ 15,537,200**

Line	Forecast Unhedged Long-term Debt - 10 and 30 Year	Weighted Average Forecast Rate	Notional	Issue Date	Maturity Date	Fiscal 2020	Fiscal 2021
93	Remaining Issues Planned for Fiscal 2020	3.76%	$ 425,000,000			$ 8,668,603	$ 15,980,000
94	Issues Planned for Fiscal 2021	4.06%	$ 500,000,000			$ -	$ 13,514,795
95	**5) Total Forecast Unhedged Long-term Debt - 10 and 30 Year**		**$ 925,000,000**			**$ 8,668,603**	**$ 29,494,795**

Line	Future Debt Hedges - 10 and 30 Year	Weighted Average Forecast Rate	Notional	Issue Date	Maturity Date	Fiscal 2020	Fiscal 2021
96	Remaining Issues Planned for Fiscal 2020	2.47%	$ 525,000,000			$ 7,544,322	$ 12,989,045
97	Issues Planned for Fiscal 2021	2.61%	$ 1,800,000,000				$ 32,914,599
98	**6) Total Future Debt Hedges - 10 and 30 Year**		**$ 2,325,000,000**			**$ 7,544,322**	**$ 45,903,644**

Line	Total Long-Term Debt Costs	Reference	Fiscal 2020	Fiscal 2021
99	1) Total Existing CAD Bonds	L85	$ 731,803,962	$ 691,772,428
100	2) Total Existing EUR Bonds in CAD	L88	14,379,370	14,379,370
101	3) Total Existing USD Bonds in USD	L91	54,250,000	54,250,000
102	4) Foreign Exchange on Existing USD Bonds	L92	16,974,829	15,537,200
103	5) Total Forecast Unhedged Long-term Debt - 10 and 30 Year	L95	8,668,603	29,494,795
104	6) Total Future Debt Hedges - 10 and 30 Year	L98	7,544,322	45,903,644
105	7) Other, including amortization of discount/issue costs and foreign exchange adjustments		(8,298,086)	138,563
106	**Total Long-Term Debt Costs**	**Schedule 8, L86**	**$ 825,323,000**	**$ 851,476,000**

Shading reflects updates to the information provided in Attachment 1 to BC Hydro's response to AMPC IR 1.4.2.2 based on information included in BC Hydro's Evidentiary Update.

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						Interest Expense	
Line	Existing CAD Bonds	Coupon or Hedged Rate	Notional	Issue Date	Maturity Date	Fiscal 2020	Fiscal 2021
1		5.30%	$ 175,000,000	03-May-04	17-Jun-19	$ 1,982,055	$ -
2		10.60%	$ 599,825,000	05-Sep-90	05-Sep-20	$ 63,581,450	$ 27,522,929
3		3.70%	$ 500,000,000	23-Aug-10	18-Dec-20	$ 18,500,000	$ 13,279,452
4		9.95%	$ 296,339,000	15-Apr-96	15-May-21	$ 29,485,731	$ 29,485,731
5		4.80%	$ 155,000,000	07-Jun-07	15-Jun-21	$ 7,440,000	$ 7,440,000
6		4.80%	$ 75,000,000	07-Jun-07	15-Jun-21	$ 3,600,000	$ 3,600,000
7		9.50%	$ 100,000,000	09-Jun-92	09-Jun-22	$ 9,500,000	$ 9,500,000
8		8.75%	$ 200,000,000	19-Aug-92	19-Aug-22	$ 17,500,000	$ 17,500,000
9		2.70%	$ 100,000,000	28-Sep-12	18-Dec-22	$ 2,700,000	$ 2,700,000
10		2.70%	$ 100,000,000	14-Jan-13	18-Dec-22	$ 2,700,000	$ 2,700,000
11		8.00%	$ 100,000,000	08-Sep-93	08-Sep-23	$ 8,000,000	$ 8,000,000
12		3.30%	$ 100,000,000	27-Aug-13	18-Dec-23	$ 3,300,000	$ 3,300,000
13		5.54%	$ 10,000,000	09-Aug-04	09-Aug-24	$ 554,000	$ 554,000
14		2.85%	$ 300,000,000	16-Jan-15	18-Jun-25	$ 8,550,000	$ 8,550,000
15		2.85%	$ 300,000,000	30-Jun-15	18-Jun-25	$ 8,550,000	$ 8,550,000
16		2.85%	$ 300,000,000	05-Nov-15	18-Jun-25	$ 8,550,000	$ 8,550,000
17		2.30%	$ 500,000,000	16-Mar-16	18-Jun-26	$ 11,500,000	$ 11,500,000
18		2.30%	$ 200,000,000	12-May-16	18-Jun-26	$ 4,600,000	$ 4,600,000
19		2.30%	$ 150,000,000	27-Jan-17	18-Jun-26	$ 3,450,000	$ 3,450,000
20		2.35%	$ 300,000,000	21-Mar-17	18-Jun-27	$ 7,050,000	$ 7,050,000
21		2.37%	$ 200,000,000	17-Oct-17	18-Jun-27	$ 4,740,000	$ 4,740,000
22		1.83%	$ 200,000,000	17-Oct-17	18-Jun-27	$ 3,660,000	$ 3,660,000
23		1.82%	$ 200,000,000	17-Oct-17	18-Jun-27	$ 3,640,000	$ 3,640,000
24		2.84%	$ 100,000,000	21-Jun-18	18-Jun-27	$ 2,840,000	$ 2,840,000
25		1.84%	$ 200,000,000	15-May-18	18-Dec-28	$ 3,680,000	$ 3,680,000
26		2.87%	$ 100,000,000	21-Jun-18	18-Dec-28	$ 2,870,000	$ 2,870,000
27		2.88%	$ 200,000,000	20-Jul-18	18-Dec-28	$ 5,760,000	$ 5,760,000
28		2.92%	$ 200,000,000	20-Jul-18	18-Dec-28	$ 5,840,000	$ 5,840,000
29		2.16%	$ 300,000,000	18-Sep-18	18-Dec-28	$ 6,480,000	$ 6,480,000
30		2.17%	$ 200,000,000	18-Sep-18	18-Dec-28	$ 4,340,000	$ 4,340,000
31		2.18%	$ 300,000,000	11-Jun-19	18-Dec-28	$ 5,267,836	$ 6,540,000
32		5.70%	$ 300,000,000	13-Jul-06	18-Jun-29	$ 17,100,000	$ 17,100,000
33		5.15%	$ 200,000,000	19-Jun-07	18-Jun-29	$ 10,300,000	$ 10,300,000
34		6.35%	$ 200,000,000	16-Jun-00	18-Jun-31	$ 12,700,000	$ 12,700,000
35		6.35%	$ 100,000,000	15-Nov-01	18-Jun-31	$ 6,350,000	$ 6,350,000
36		6.35%	$ 100,000,000	18-Dec-01	18-Jun-31	$ 6,350,000	$ 6,350,000
37		6.35%	$ 400,000,000	16-Sep-05	18-Jun-31	$ 25,400,000	$ 25,400,000
38		5.00%	$ 100,000,000	10-Apr-12	18-Jun-31	$ 5,000,000	$ 5,000,000
39		5.00%	$ 110,000,000	20-Apr-12	18-Jun-31	$ 5,500,000	$ 5,500,000
40		5.00%	$ 100,000,000	29-Oct-12	18-Jun-31	$ 5,000,000	$ 5,000,000
41		4.95%	$ 150,000,000	08-Dec-08	18-Jun-40	$ 7,425,000	$ 7,425,000
42		4.95%	$ 300,000,000	26-May-09	18-Jun-40	$ 14,850,000	$ 14,850,000
43		4.95%	$ 300,000,000	15-Jul-09	18-Jun-40	$ 14,850,000	$ 14,850,000
44		4.95%	$ 500,000,000	11-Jan-10	18-Jun-40	$ 24,750,000	$ 24,750,000
45		3.54%	$ 70,097,000	08-May-12	08-May-42	$ 2,481,434	$ 2,481,434
46		3.22%	$ 97,715,000	11-Jun-12	11-Jun-42	$ 3,146,423	$ 3,146,423
47		4.30%	$ 100,000,000	08-Sep-10	18-Jun-42	$ 4,300,000	$ 4,300,000
48		4.30%	$ 500,000,000	11-Apr-11	18-Jun-42	$ 21,500,000	$ 21,500,000
49		4.30%	$ 500,000,000	06-Jun-11	18-Jun-42	$ 21,500,000	$ 21,500,000
50		4.30%	$ 300,000,000	27-Oct-11	18-Jun-42	$ 12,900,000	$ 12,900,000
51		4.30%	$ 200,000,000	01-Jun-12	18-Jun-42	$ 8,600,000	$ 8,600,000
52		4.30%	$ 200,000,000	28-Sep-12	18-Jun-42	$ 8,600,000	$ 8,600,000
53		3.29%	$ 54,786,000	10-Jul-12	10-Jul-42	$ 1,802,459	$ 1,802,459
54		3.20%	$ 200,000,000	04-Dec-12	18-Jun-44	$ 6,400,000	$ 6,400,000
55		3.20%	$ 300,000,000	20-Jun-13	18-Jun-44	$ 9,600,000	$ 9,600,000
56		3.20%	$ 300,000,000	02-Aug-13	18-Jun-44	$ 9,600,000	$ 9,600,000
57		3.20%	$ 400,000,000	17-Sep-13	18-Jun-44	$ 12,800,000	$ 12,800,000
58		3.20%	$ 265,000,000	14-Apr-14	18-Jun-44	$ 8,480,000	$ 8,480,000
59		3.20%	$ 500,000,000	20-Jun-14	18-Jun-44	$ 16,000,000	$ 16,000,000
60		3.20%	$ 600,000,000	26-Sep-14	18-Jun-44	$ 19,200,000	$ 19,200,000
61		4.90%	$ 200,000,000	29-Jun-07	18-Jun-48	$ 9,800,000	$ 9,800,000
62		4.90%	$ 170,000,000	19-May-09	18-Jun-48	$ 8,330,000	$ 8,330,000
63		4.90%	$ 50,000,000	30-Sep-11	18-Jun-48	$ 2,450,000	$ 2,450,000
64		2.80%	$ 400,000,000	01-May-15	18-Jun-48	$ 11,200,000	$ 11,200,000
65		2.80%	$ 200,000,000	02-Jun-15	18-Jun-48	$ 5,600,000	$ 5,600,000
66		2.80%	$ 300,000,000	08-Sep-15	18-Jun-48	$ 8,400,000	$ 8,400,000
67		2.80%	$ 300,000,000	18-Jan-16	18-Jun-48	$ 8,400,000	$ 8,400,000
68		3.00%	$ 300,000,000	23-Sep-16	18-Jun-48	$ 9,000,000	$ 9,000,000
69		3.01%	$ 200,000,000	25-Nov-16	18-Jun-48	$ 6,020,000	$ 6,020,000
70		2.87%	$ 200,000,000	21-Jun-17	18-Jun-48	$ 5,740,000	$ 5,740,000
71		2.80%	$ 100,000,000	21-Jun-17	18-Jun-48	$ 2,800,000	$ 2,800,000
72		2.80%	$ 100,000,000	26-Sep-17	18-Jun-48	$ 2,800,000	$ 2,800,000
73		2.27%	$ 200,000,000	26-Sep-17	18-Jun-48	$ 4,540,000	$ 4,540,000
74		2.14%	$ 200,000,000	16-Apr-18	18-Jun-48	$ 4,280,000	$ 4,280,000
75		2.80%	$ 300,000,000	16-Apr-18	18-Jun-48	$ 8,400,000	$ 8,400,000
76		3.36%	$ 200,000,000	20-Jul-18	18-Jun-48	$ 6,720,000	$ 6,720,000

Line	Existing CAD Bonds	Coupon or Hedged Rate	Notional	Issue Date	Maturity Date	Interest Expense Fiscal 2020	Interest Expense Fiscal 2021
77		3.07%	$ 150,000,000	24-Jun-19	18-Jun-48	$ 3,545,219	$ 4,605,000
78		3.35%	$ 100,000,000	24-Aug-18	18-Jun-50	$ 3,350,000	$ 3,350,000
79		3.37%	$ 100,000,000	24-Aug-18	18-Jun-50	$ 3,370,000	$ 3,370,000
80		3.36%	$ 250,000,000	24-Aug-18	18-Jun-50	$ 8,400,000	$ 8,400,000
81		3.16%	$ 50,000,000	07-Jun-19	18-Jun-50	$ 1,289,973	$ 1,580,000
82		2.95%	$ 50,000,000	07-Jun-19	18-Jun-50	$ 1,204,247	$ 1,475,000
83		3.50%	$ 60,000,000	30-Jan-13	18-Jun-55	$ 2,100,000	$ 2,100,000
84		3.30%	$ 50,000,000	27-May-13	18-Jun-62	$ 1,650,000	$ 1,650,000
85	**1) Total Existing CAD Bonds**		**$ 18,438,762,000**			**$ 722,085,825**	**$ 681,717,428**

Line	Existing Euro Bonds (coupons fully hedged to CAD)	Coupon Rate (CAD Swap Rate)	Notional (in CAD)	Issue Date	Maturity Date	Fiscal 2020	Fiscal 2021
86		2.46%	$ 390,750,000	08-Oct-15	08-Oct-25	$ 9,607,370	$ 9,607,370
87		2.39%	$ 200,000,000	20-Jul-16	20-Jul-32	$ 4,772,000	$ 4,772,000
88	**2) Total Existing EUR Bonds in CAD**		**$ 590,750,000**			**$ 14,379,370**	**$ 14,379,370**

Line	Existing USD$ Bonds (coupons not hedged to CAD)	Coupon Rate	Notional (in USD)	Issue Date	Maturity Date	Fiscal 2020	Fiscal 2021
89		6.50%	$ 500,000,000	24-Jan-96	15-Jan-26	$ 32,500,000	$ 32,500,000
90		7.25%	$ 300,000,000	29-Aug-96	01-Sep-36	$ 21,750,000	$ 21,750,000
91	**3) Total Existing USD Bonds in USD**		**$ 800,000,000**			**$ 54,250,000**	**$ 54,250,000**

Line	Existing USD Bonds - Foreign Exchange	Fiscal 2020	Fiscal 2021
92	**4) Foreign Exchange on Existing USD Bonds**	**$ 16,974,829**	**$ 15,537,200**

Line	Forecast Unhedged Long-term Debt - 10 and 30 Year	Weighted Average Forecast Rate	Notional	Issue Date	Maturity Date	Fiscal 2020	Fiscal 2021
93	Remaining Issues Planned for Fiscal 2020	3.76%	$ 425,000,000			$ 8,668,603	$ 15,980,000
94	Issues Planned for Fiscal 2021	4.06%	$ 500,000,000			$ -	$ 13,514,795
95	**5) Total Forecast Unhedged Long-term Debt - 10 and 30 Year**		**$ 925,000,000**			**$ 8,668,603**	**$ 29,494,795**

Line	Future Debt Hedges - 10 and 30 Year	Weighted Average Hedged Rate	Notional	Issue Date	Maturity Date	Fiscal 2020	Fiscal 2021
96	Remaining Issues Planned for Fiscal 2020	2.78%	$ 525,000,000			$ 8,464,100	$ 14,572,625
97	Issues Planned for Fiscal 2021	2.98%	$ 1,800,000,000			$ -	$ 37,719,080
98	**6) Total Future Debt Hedges - 10 and 30 Year**		**$ 2,325,000,000**			**$ 8,464,100**	**$ 52,291,705**

Line	Total Long-Term Debt Costs	Reference	Fiscal 2020	Fiscal 2021
99	1) Total Existing CAD Bonds	L85	$ 722,085,825	$ 681,717,428
100	2) Total Existing EUR Bonds in CAD	L88	14,379,370	14,379,370
101	3) Total Existing USD Bonds in USD	L91	54,250,000	54,250,000
102	4) Foreign Exchange on Existing USD Bonds	L92	16,974,829	15,537,200
103	5) Total Forecast Unhedged Long-term Debt - 10 and 30 Year	L95	8,668,603	29,494,795
104	6) Total Future Debt Hedges - 10 and 30 Year	L98	8,464,100	52,291,705
105	7) Other, including amortization of discount/issue costs and foreign exchange adjustments		(6,481,086)	2,472,463
106	**Total Long-Term Debt Costs**		**$ 818,341,641**	**$ 850,142,961**

Shading reflects revisions to the information provided in Attachment 1 to BC Hydro's response to AMPC IR 2.26.1, as requested.

26.0 Finance Charges

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.4.2.2 and Attachment 1, pdf pp. 45-48

In its response, BC Hydro provides a schedule showing the calculation of long-term debt costs. The table shows Future Debt Hedge interest rates, but excludes the impact of hedging gains and losses. BC Hydro explains that these gains and losses are recorded in the Debt Management Regulatory Account and amortized in accordance with BCUC Order No. G-42-16.

AMPC is seeking clarification of the data provided in the schedule in order to understand BC Hydro's calculation of long-term debt costs.

2.26.2 Please explain why BC Hydro did not include hedged interest rate impacts (as provided in response to AMPC IR 1.4.9) in Schedule 2.2 of Appendix A, Debt Management Regulatory Account, for 2020 and 2021.

RESPONSE:

BC Hydro did not include hedged interest rate impacts in Schedule 2.2 of Appendix A as Schedule 2.2 of Appendix A only summarizes activity related to BC Hydro’s regulatory accounts. In accordance with BCUC Order No. G-42-16, the Debt Management Regulatory account captures the gains and losses on future debt hedges and these have been reflected in Schedule 2.2 of Appendix A.

26.0 Finance Charges

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.4.2.2 and Attachment 1, pdf pp. 45-48

In its response, BC Hydro provides a schedule showing the calculation of long-term debt costs. The table shows Future Debt Hedge interest rates, but excludes the impact of hedging gains and losses. BC Hydro explains that these gains and losses are recorded in the Debt Management Regulatory Account and amortized in accordance with BCUC Order No. G-42-16.

AMPC is seeking clarification of the data provided in the schedule in order to understand BC Hydro's calculation of long-term debt costs.

2.26.3 Please revise the table provided in response to AMPC IR 1.4.2.2 Attachment 1 to reflect those interest rates for planned issues from 2020 and 2021 (from Appendix A, Schedule 8.0, Line 83).

RESPONSE:

The financial information provided in this response has been updated based on the information included in BC Hydro's Evidentiary Update.

Please refer to Attachment 1 to BC Hydro's response to AMPC IR 2.26.1 in conjunction with Attachment 1 of this response. Attachment 1 of this response is the same as Attachment 1 to BC Hydro's response to AMPC IR 2.26.1, except it has been revised to use the "Interest Rate – Planned Issues" rates from Appendix A, Schedule 8.0 (updated based on the information included in BC Hydro's Evidentiary Update) for the "Forecast Unhedged Long-term Debt – 10 and 30-Year" for fiscal years 2020 and 2021. These interest rates are provided by the Treasury Board of the Government of B.C., dated January 2019, and reflect forecast 10-year long-term rates. Lines that have changed from Attachment 1 to BC Hydro's response to AMPC IR 2.26.1 are highlighted with grey shading in Attachment 1 to this response.

It should be noted that while the interest rates for planned long-term debt issues from Appendix A, Schedule 8, line 83 of the Application are 10-year rates, BC Hydro forecasts a 50/50 mix of 10-year and 30-year long-term debt issuance. Please refer to BC Hydro's response to AMPC IR 2.26.4 for additional information on how BC Hydro determines the 30-year interest rate for planned long-term debt issues.

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Line	Existing CAD Bonds	Coupon Rate	Notional	Issue Date	Maturity Date	Interest Expense Fiscal 2020	Interest Expense Fiscal 2021
1		5.30%	$ 175,000,000	03-May-04	17-Jun-19	$ 1,982,055	$ -
2		10.60%	$ 599,825,000	05-Sep-90	05-Sep-20	$ 63,581,450	$ 27,522,929
3		3.70%	$ 500,000,000	23-Aug-10	18-Dec-20	$ 18,500,000	$ 13,279,452
4		9.95%	$ 296,339,000	15-Apr-96	15-May-21	$ 29,485,731	$ 29,485,731
5		4.80%	$ 155,000,000	07-Jun-07	15-Jun-21	$ 7,440,000	$ 7,440,000
6		4.80%	$ 75,000,000	07-Jun-07	15-Jun-21	$ 3,600,000	$ 3,600,000
7		9.50%	$ 100,000,000	09-Jun-92	09-Jun-22	$ 9,500,000	$ 9,500,000
8		8.75%	$ 200,000,000	19-Aug-92	19-Aug-22	$ 17,500,000	$ 17,500,000
9		2.70%	$ 100,000,000	28-Sep-12	18-Dec-22	$ 2,700,000	$ 2,700,000
10		2.70%	$ 100,000,000	14-Jan-13	18-Dec-22	$ 2,700,000	$ 2,700,000
11		8.00%	$ 100,000,000	08-Sep-93	08-Sep-23	$ 8,000,000	$ 8,000,000
12		3.30%	$ 100,000,000	27-Aug-13	18-Dec-23	$ 3,300,000	$ 3,300,000
13		5.54%	$ 10,000,000	09-Aug-04	09-Aug-24	$ 554,000	$ 554,000
14		2.85%	$ 300,000,000	16-Jan-15	18-Jun-25	$ 8,550,000	$ 8,550,000
15		2.85%	$ 300,000,000	30-Jun-15	18-Jun-25	$ 8,550,000	$ 8,550,000
16		2.85%	$ 300,000,000	05-Nov-15	18-Jun-25	$ 8,550,000	$ 8,550,000
17		2.30%	$ 500,000,000	16-Mar-16	18-Jun-26	$ 11,500,000	$ 11,500,000
18		2.30%	$ 200,000,000	12-May-16	18-Jun-26	$ 4,600,000	$ 4,600,000
19		2.30%	$ 150,000,000	27-Jan-17	18-Jun-26	$ 3,450,000	$ 3,450,000
20		2.55%	$ 300,000,000	21-Mar-17	18-Jun-27	$ 7,650,000	$ 7,650,000
21		2.55%	$ 200,000,000	17-Oct-17	18-Jun-27	$ 5,100,000	$ 5,100,000
22		2.55%	$ 200,000,000	17-Oct-17	18-Jun-27	$ 5,100,000	$ 5,100,000
23		2.55%	$ 200,000,000	17-Oct-17	18-Jun-27	$ 5,100,000	$ 5,100,000
24		2.55%	$ 100,000,000	21-Jun-18	18-Jun-27	$ 2,550,000	$ 2,550,000
25		2.95%	$ 200,000,000	15-May-18	18-Dec-28	$ 5,900,000	$ 5,900,000
26		2.95%	$ 100,000,000	21-Jun-18	18-Dec-28	$ 2,950,000	$ 2,950,000
27		2.95%	$ 200,000,000	20-Jul-18	18-Dec-28	$ 5,900,000	$ 5,900,000
28		2.95%	$ 200,000,000	20-Jul-18	18-Dec-28	$ 5,900,000	$ 5,900,000
29		2.95%	$ 300,000,000	18-Sep-18	18-Dec-28	$ 8,850,000	$ 8,850,000
30		2.95%	$ 200,000,000	18-Sep-18	18-Dec-28	$ 5,900,000	$ 5,900,000
31		2.95%	$ 300,000,000	11-Jun-19	18-Dec-28	$ 7,128,493	$ 8,850,000
32		5.70%	$ 300,000,000	13-Jul-06	18-Jun-29	$ 17,100,000	$ 17,100,000
33		5.15%	$ 200,000,000	19-Jun-07	18-Jun-29	$ 10,300,000	$ 10,300,000
34		6.35%	$ 200,000,000	16-Jun-00	18-Jun-31	$ 12,700,000	$ 12,700,000
35		6.35%	$ 100,000,000	15-Nov-01	18-Jun-31	$ 6,350,000	$ 6,350,000
36		6.35%	$ 100,000,000	18-Dec-01	18-Jun-31	$ 6,350,000	$ 6,350,000
37		6.35%	$ 400,000,000	16-Sep-05	18-Jun-31	$ 25,400,000	$ 25,400,000
38		5.00%	$ 100,000,000	10-Apr-12	18-Jun-31	$ 5,000,000	$ 5,000,000
39		5.00%	$ 110,000,000	20-Apr-12	18-Jun-31	$ 5,500,000	$ 5,500,000
40		5.00%	$ 100,000,000	29-Oct-12	18-Jun-31	$ 5,000,000	$ 5,000,000
41		4.95%	$ 150,000,000	08-Dec-08	18-Jun-40	$ 7,425,000	$ 7,425,000
42		4.95%	$ 300,000,000	26-May-09	18-Jun-40	$ 14,850,000	$ 14,850,000
43		4.95%	$ 300,000,000	15-Jul-09	18-Jun-40	$ 14,850,000	$ 14,850,000
44		4.95%	$ 500,000,000	11-Jan-10	18-Jun-40	$ 24,750,000	$ 24,750,000
45		3.54%	$ 70,097,000	08-May-12	08-May-42	$ 2,481,434	$ 2,481,434
46		3.22%	$ 97,715,000	11-Jun-12	11-Jun-42	$ 3,146,423	$ 3,146,423
47		4.30%	$ 100,000,000	08-Sep-10	18-Jun-42	$ 4,300,000	$ 4,300,000
48		4.30%	$ 500,000,000	11-Apr-11	18-Jun-42	$ 21,500,000	$ 21,500,000
49		4.30%	$ 500,000,000	06-Jun-11	18-Jun-42	$ 21,500,000	$ 21,500,000
50		4.30%	$ 300,000,000	27-Oct-11	18-Jun-42	$ 12,900,000	$ 12,900,000
51		4.30%	$ 200,000,000	01-Jun-12	18-Jun-42	$ 8,600,000	$ 8,600,000
52		4.30%	$ 200,000,000	28-Sep-12	18-Jun-42	$ 8,600,000	$ 8,600,000
53		3.29%	$ 54,786,000	10-Jul-12	10-Jul-42	$ 1,802,459	$ 1,802,459
54		3.20%	$ 200,000,000	04-Dec-12	18-Jun-44	$ 6,400,000	$ 6,400,000
55		3.20%	$ 300,000,000	20-Jun-13	18-Jun-44	$ 9,600,000	$ 9,600,000
56		3.20%	$ 300,000,000	02-Aug-13	18-Jun-44	$ 9,600,000	$ 9,600,000
57		3.20%	$ 400,000,000	17-Sep-13	18-Jun-44	$ 12,800,000	$ 12,800,000
58		3.20%	$ 265,000,000	14-Apr-14	18-Jun-44	$ 8,480,000	$ 8,480,000
59		3.20%	$ 500,000,000	20-Jun-14	18-Jun-44	$ 16,000,000	$ 16,000,000
60		3.20%	$ 600,000,000	26-Sep-14	18-Jun-44	$ 19,200,000	$ 19,200,000
61		4.90%	$ 200,000,000	29-Jun-07	18-Jun-48	$ 9,800,000	$ 9,800,000
62		4.90%	$ 170,000,000	19-May-09	18-Jun-48	$ 8,330,000	$ 8,330,000
63		4.90%	$ 50,000,000	30-Sep-11	18-Jun-48	$ 2,450,000	$ 2,450,000
64		2.80%	$ 400,000,000	01-May-15	18-Jun-48	$ 11,200,000	$ 11,200,000
65		2.80%	$ 200,000,000	02-Jun-15	18-Jun-48	$ 5,600,000	$ 5,600,000
66		2.80%	$ 300,000,000	08-Sep-15	18-Jun-48	$ 8,400,000	$ 8,400,000
67		2.80%	$ 300,000,000	18-Jan-16	18-Jun-48	$ 8,400,000	$ 8,400,000
68		2.80%	$ 300,000,000	23-Sep-16	18-Jun-48	$ 8,400,000	$ 8,400,000
69		2.80%	$ 200,000,000	25-Nov-16	18-Jun-48	$ 5,600,000	$ 5,600,000
70		2.80%	$ 200,000,000	21-Jun-17	18-Jun-48	$ 5,600,000	$ 5,600,000
71		2.80%	$ 100,000,000	21-Jun-17	18-Jun-48	$ 2,800,000	$ 2,800,000
72		2.80%	$ 100,000,000	26-Sep-17	18-Jun-48	$ 2,800,000	$ 2,800,000
73		2.80%	$ 200,000,000	26-Sep-17	18-Jun-48	$ 5,600,000	$ 5,600,000
74		2.80%	$ 200,000,000	16-Apr-18	18-Jun-48	$ 5,600,000	$ 5,600,000
75		2.80%	$ 300,000,000	16-Apr-18	18-Jun-48	$ 8,400,000	$ 8,400,000
76		2.80%	$ 200,000,000	20-Jul-18	18-Jun-48	$ 5,600,000	$ 5,600,000
77		2.80%	$ 150,000,000	24-Jun-19	18-Jun-48	$ 3,233,425	$ 4,200,000

Line	Existing CAD Bonds	Coupon Rate	Notional	Issue Date	Maturity Date	Interest Expense Fiscal 2020	Interest Expense Fiscal 2021
78		2.95%	$ 100,000,000	24-Aug-18	18-Jun-50	$ 2,950,000	$ 2,950,000
79		2.95%	$ 100,000,000	24-Aug-18	18-Jun-50	$ 2,950,000	$ 2,950,000
80		2.95%	$ 250,000,000	24-Aug-18	18-Jun-50	$ 7,375,000	$ 7,375,000
81		2.95%	$ 50,000,000	07-Jun-19	18-Jun-50	$ 1,204,247	$ 1,475,000
82		2.95%	$ 50,000,000	07-Jun-19	18-Jun-50	$ 1,204,247	$ 1,475,000
83		3.50%	$ 60,000,000	30-Jan-13	18-Jun-55	$ 2,100,000	$ 2,100,000
84		3.30%	$ 50,000,000	27-May-13	18-Jun-62	$ 1,650,000	$ 1,650,000
85	**1) Total Existing CAD Bonds**		**$ 18,438,762,000**			**$ 731,803,962**	**$ 691,772,428**

Line	Existing Euro Bonds (coupons fully hedged to CAD)	Coupon Rate (CAD Swap Rate)	Notional (in CAD)	Issue Date	Maturity Date	Fiscal 2020	Fiscal 2021
86		2.46%	$ 390,750,000	08-Oct-15	08-Oct-25	$ 9,607,370	$ 9,607,370
87		2.39%	$ 200,000,000	20-Jul-16	20-Jul-32	$ 4,772,000	$ 4,772,000
88	**2) Total Existing EUR Bonds in CAD**		**$ 590,750,000**			**$ 14,379,370**	**$ 14,379,370**

Line	Existing USD$ Bonds (coupons not hedged to CAD)	Coupon Rate	Notional (in USD)	Issue Date	Maturity Date	Fiscal 2020	Fiscal 2021
89		6.50%	$ 500,000,000	24-Jan-96	15-Jan-26	$ 32,500,000	$ 32,500,000
90		7.25%	$ 300,000,000	29-Aug-96	01-Sep-36	$ 21,750,000	$ 21,750,000
91	**3) Total Existing USD Bonds in USD**		**$ 800,000,000**			**$ 54,250,000**	**$ 54,250,000**

Line	Existing USD Bonds - Foreign Exchange	Fiscal 2020	Fiscal 2021
92	**4) Foreign Exchange on Existing USD Bonds**	**$ 16,974,829**	**$ 15,537,200**

Line	Forecast Unhedged Long-term Debt - 10 and 30 Year	Government of B.C. 10-yr Forecast Rate	Notional	Issue Date	Maturity Date	Fiscal 2020	Fiscal 2021
93	Remaining Issues Planned for Fiscal 2020	3.46%	$ 425,000,000			$ 7,976,959	$ 14,705,000
94	Issues Planned for Fiscal 2021	3.76%	$ 500,000,000			$ -	$ 12,516,164
95	**5) Total Forecast Unhedged Long-term Debt - 10 and 30 Year**		**$ 925,000,000**			**$ 7,976,959**	**$ 27,221,164**

Line	Future Debt Hedges - 10 and 30 Year	Weighted Average Forecast Rate	Notional	Issue Date	Maturity Date	Fiscal 2020	Fiscal 2021
96	Remaining Issues Planned for Fiscal 2020	2.47%	$ 525,000,000			$ 7,544,322	$ 12,989,045
97	Issues Planned for Fiscal 2021	2.61%	$ 1,800,000,000				$ 32,914,599
98	**6) Total Future Debt Hedges - 10 and 30 Year**		**$ 2,325,000,000**			**$ 7,544,322**	**$ 45,903,644**

Line	Total Long-Term Debt Costs	Reference	Fiscal 2020	Fiscal 2021
99	1) Total Existing CAD Bonds	L85	$ 731,803,962	$ 691,772,428
100	2) Total Existing EUR Bonds in CAD	L88	14,379,370	14,379,370
101	3) Total Existing USD Bonds in USD	L91	54,250,000	54,250,000
102	4) Foreign Exchange on Existing USD Bonds	L92	16,974,829	15,537,200
103	5) Total Forecast Unhedged Long-term Debt - 10 and 30 Year	L95	7,976,959	27,221,164
104	6) Total Future Debt Hedges - 10 and 30 Year	L98	7,544,322	45,903,644
105	7) Other, including amortization of discount/issue costs and foreign exchange adjustments		(8,298,086)	138,563
106	**Total Long-Term Debt Costs**		**$ 824,631,356**	**$ 849,202,370**

Shading reflects revisions to the information provided in Attachment 1 to BC Hydro's response to AMPC IR 2.26.1, as requested in AMPC IR 2.26.3.

26.0 Finance Charges

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.4.2.2 and Attachment 1, pdf pp. 45-48

In its response, BC Hydro provides a schedule showing the calculation of long-term debt costs. The table shows Future Debt Hedge interest rates, but excludes the impact of hedging gains and losses. BC Hydro explains that these gains and losses are recorded in the Debt Management Regulatory Account and amortized in accordance with BCUC Order No. G-42-16.

AMPC is seeking clarification of the data provided in the schedule in order to understand BC Hydro's calculation of long-term debt costs.

2.26.4 Why do the interest rates provided in the schedule not reconcile to the forecast interest rates for long-term debt included in Table 8-6 of the Application?

RESPONSE:

BC Hydro forecasts unhedged long-term debt issuances to be a 50/50 mix of 10-year and 30-year debt. The interest rates in the “Forecast Unhedged Long-term Debt – 10 and 30 Year” section of Attachment 1 to BC Hydro’s response to AMPC IR 1.4.2.2 reflect this weighting, while the long-term interest rates included in Table 8-6 of Chapter 8 of the Application are 10-year interest rates.

Notwithstanding that Table 8-6 presents 10-year interest rates, BC Hydro also uses forecast 30-year interest rates to forecast unhedged debt issuance costs in preparing the Application. More specifically, for 30-year interest rates, BC Hydro’s forecast uses the 10-year interest rates provided by the Treasury Board of the Government of B.C. (i.e., the Canadian Long-term Interest Rate shown in Table 8-6 of Chapter 8 of the Application), and adds a spread to reflect the five-year historical average interest rate spread between Province of B.C. 10-year and 30-year bond yields.

For hedged long-term debt issuances (Future Debt Hedges), BC Hydro forecasts finance charges using forward swap and bond lock rates with a mix of 10-year and 30-year terms, based on executed and planned hedges. The interest rates in the “Future Debt Hedges – 10 and 30 Year” section of Attachment 1 to BC Hydro’s response to AMPC IR 2.26.1 reflect this weighting and current forward swap and bond lock rates as of the date of the forecast. Forecast interest rates for forward swaps are based on Canadian swap forward rates, plus a spread between the Province of B.C. Bond and Canadian swap curves, plus forecast commissions and fees. Forecast interest rates for bond locks are based on Government of Canada

forward bond yields, plus a spread between the Province of B.C. and Government of Canada Bond yields, plus forecast commissions and fees.

Please also refer to Attachment 1 to BC Hydro's response to AMPC IR 2.26.1, which is an update of the table provided in Attachment 1 to BC Hydro's response to AMPC IR 1.4.2.2. The financial information provided in this response has been updated based on the information included in BC Hydro's Evidentiary Update.

26.0 Finance Charges

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.4.2.2 and Attachment 1, pdf pp. 45-48

In its response, BC Hydro provides a schedule showing the calculation of long-term debt costs. The table shows Future Debt Hedge interest rates, but excludes the impact of hedging gains and losses. BC Hydro explains that these gains and losses are recorded in the Debt Management Regulatory Account and amortized in accordance with BCUC Order No. G-42-16.

AMPC is seeking clarification of the data provided in the schedule in order to understand BC Hydro's calculation of long-term debt costs.

2.26.5 Please revise the table provided in response to AMPC IR 1.4.2.2 Attachment 1 to reflect those interest rates for long term debt included in Table 8 6 of the Application.

RESPONSE:

The financial information provided in this response has been updated based on the information included in BC Hydro's Evidentiary Update.

Please refer to Attachment 1 to BC Hydro's response to AMPC IR 2.26.3, as the rates in Table 8-6 of Chapter 8 of the Application are the same as those shown in Appendix A, Schedule 8.0, line 83 (referred to in BC Hydro's response to AMPC IR 2.26.3).

27.0 Finance Charges

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.4.2.3, pdf p. 49

In its response, BC Hydro provides a table that shows its sinking income fund is 3.5% of the sinking fund balances for both F2020 and F2021.

AMPC is seeking clarification on how these figures were derived and how variances are captured.

2.27.1 Please explain in detail how BC Hydro determined a sinking income fund of 3.5%, including supporting calculations.

RESPONSE:

The 3.5 per cent sinking fund income for fiscal 2020 and fiscal 2021 shown in BC Hydro's response to AMPC IR 1.4.2.3 was calculated solely in response to that question, in the manner requested in that question. There are no further supporting calculations beyond those shown in that response.

BC Hydro forecasts sinking fund income using the forecast U.S. long-term interest rate provided by the Treasury Board of the Government of B.C. (Treasury Board) for the current fiscal year, which was 3.55 per cent in the Application (based on fiscal 2019 using October 2018 Treasury Board assumptions) and updated to 3.85 per cent in the Evidentiary Update (based on fiscal 2020 using January 2019 Treasury Board assumptions). The sinking fund income and year-end balances are translated to Canadian dollars using the USD$/C$ exchange rate assumptions, as provided by Treasury Board, for each respective fiscal year. Please note that all of BC Hydro's sinking funds are denominated in U.S. dollars.

27.0 Finance Charges

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.4.2.3, pdf p. 49

In its response, BC Hydro provides a table that shows its sinking income fund is 3.5% of the sinking fund balances for both F2020 and F2021.

AMPC is seeking clarification on how these figures were derived and how variances are captured.

2.27.2 Are variances between forecast and actual earnings for sinking funds captured in a regulatory and/or deferral account? Please fully explain your response.

RESPONSE:

Yes, variances between forecast and actual earnings for sinking funds are captured in the Total Finance Charges Regulatory Account.

28.0 Finance Charges

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.4.3, pdf p. 50

In its response, BC Hydro states that "[t]o 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."

AMPC is seeking additional information on the data and assumptions that BC Hydro relied on to forecast finance charges.

2.28.1 Please identify the market variables, economic forecasts, and assumptions that BC Hydro relied on to develop its finance charges forecast and provide copies of all relevant documents.

RESPONSE:

The table below provides a list of the market variables, economic forecasts and key assumptions directly used by BC Hydro to forecast finance charges.

Market Variable, Economic Forecast or Key Assumption	Source
Canadian Short-term Interest Rate (%)	Treasury Board of the Government of B.C.
Canadian Long-term Interest Rate (%)	Treasury Board of the Government of B.C.
U.S. Long-term Interest Rate (%)	Treasury Board of the Government of B.C.
USD$/CAD$ Exchange Rate	Treasury Board of the Government of B.C.
Spread between Province of B.C. 10-year and 30-year bond yields	Bloomberg
Canadian Swap Forward Rates	Bloomberg
Government of Canada 30-year Forward Bond Yields	Bloomberg
Spread between Province of B.C. Bond and Canadian Swap Curves (10-year and 30-year)	Bloomberg
Commissions and Fiscal Agency Fees for Province of B.C. Bond issues (10-year and 30-year)	Government of B.C.’s Debt Management Branch - Financing Alternatives Report
Credit spread between the Province of B.C. and Government of Canada Bond yields (10-year and 30-year)	Government of B.C.’s Debt Management Branch - Financing Alternatives Report

Market Variable, Economic Forecast or Key Assumption	Source
Planned unhedged long-term debt issues 50/50 mix between 10-year and 30-year debt	**BC Hydro Treasury. Please refer to BC Hydro's response to AMPC IR 2.26.4 for further information.**
Variable rate debt target	**BC Hydro Treasury. Please refer to BC Hydro's response to AMPC IR 2.25.1 for further information and supporting documents and policies.**

BC Hydro has provided the source document for the interest and foreign exchange rate forecasts from the Treasury Board of the Government of B.C. based on the information included in BC Hydro's Evidentiary Update as Attachment 1 to this response. These forecast interest and foreign exchange rates provided by the Treasury Board of the Government of B.C. in January 2019 were also provided in BC Hydro's response to BCOAPO IR 1.72.1.

Source documents from Bloomberg are from a paid subscription service and have not been provided as Bloomberg has advised that distribution of this information is prohibited under the terms of Bloomberg's service contract with BC Hydro.

The source document for the Government of B.C.'s Debt Management Branch Financing Alternatives Report used in BC Hydro's Evidentiary Update is provided as Attachment 2 to this response.

BC Hydro's F2020 Liability Risk Management Annual Strategic Plan, which outlines BC Hydro's current debt management strategy and provides constraints for the forecast debt, is provided as Attachment 3 to BC Hydro's response to AMPC IR 2.25.1.

Indirectly, the finance charge forecast also relies on other market variables, economic forecasts and assumptions, which underlie internal BC Hydro forecasts, such as the load forecast and capital plan, which impact consolidated borrowing requirements. These internal forecasts and other assumptions are discussed further in the relevant sections of the Application.

Interest and Exchange Rate Forecasts - January 4, 2019

Fiscal Year Ending March 31		F 2019/20	F 2020/21
Short-term Interest Rates			
Canada	3 month T-Bill (1)	2.20%	2.54%
	Credit Spread (2)	0.15%	0.15%
	All-in Rates	**2.35%**	**2.69%**
US	3 month T-Bill (1)	2.91%	3.09%
	Credit Spread (2)	0.25%	0.25%
	All-in Rates	**3.16%**	**3.34%**
Long-term Interest Rates			
Canada	Gov't Treasury Bond (10yr) (1)	2.64%	2.94%
	Credit Spread (2)	0.75%	0.75%
	Issuance Costs and Fiscal Fees (2)	0.07%	0.07%
	All-in Rates	**3.46%**	**3.76%**
US	Long Term Bond (10yr) (1)	3.33%	3.42%
	Credit Spread (2)	0.50%	0.50%
	Issuance Costs and Fiscal Fees (2)	0.02%	0.02%
	All-in Rates	**3.85%**	**3.94%**
US$ Exchange Rates			
CAD/USD (1)		1.3064	1.2864
USD/CAD (1)		0.7655	0.7774

Notes:

(1) FX Rate, 3 month T-Bill and Long Term Bond as per BC Treasury Board Staff January 4, 2019 assumptions.

(2) Credit spreads, issuance costs and fiscal fees confirmed by Provincial Treasury on December 12, 2018.

Financing Alternatives Report
(For Indicative Purposes Only)

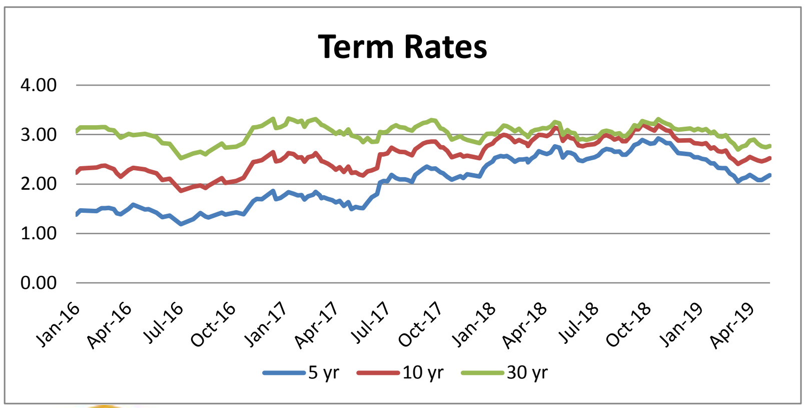
As of: **28-May-19**

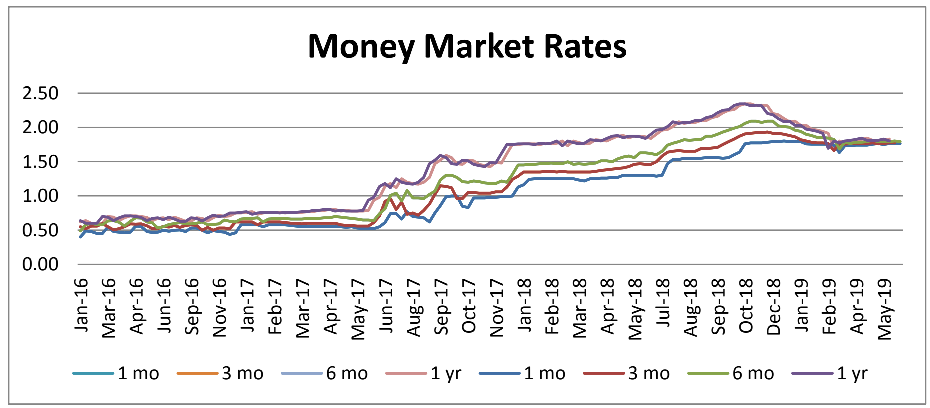
Money Market Rates (%)

Term (Months)	1	2	3	6	9	12
Rate	1.750	1.750	1.760	1.780	1.785	1.790
FAL Fee	0.0125	0.0125	0.0125	0.0125	0.0125	0.0125
Yield to Client	**1.763**	**1.763**	**1.773**	**1.793**	**1.798**	**1.803**

Term Rates (%)

Term (Years)	3	5	7	10	20	30
Canada Benchmark	CAN 0.5 03/01/22	CAN 2.25 03/01/24	CAN 1.5 06/01/26	CAN 2.25 06/01/29	CAN 5 06/01/37	CAN 2.75 12/01/48
Can (Benchmark) Yield	1.505	1.470	1.523	1.577	1.794	1.832
Spread	0.240	0.410	0.540	0.675	0.755	0.735
Yield to Investor	1.745	1.880	2.063	2.252	2.549	2.567
Commission	0.087	0.084	0.069	0.067	0.045	0.034
Yield to BC	1.865	1.964	2.132	2.319	2.594	2.601
FAL Fee	0.0333	0.0333	0.0333	0.0333	0.0333	0.0333
Yield to Client	**1.899**	**1.997**	**2.165**	**2.352**	**2.628**	**2.634**





British Columbia

Spot Rate		CAN Interest Rates		US Interest Rates	
USD per CAD	1.3487	**Overnight Rate**	1.75	**Fed Funds Rate**	2.5
CAD per USD	0.7415	**Prime Rate (Can)**	3.95	**Prime Rate (US)**	5.5

Contact Information: capital.markets@gov.bc.ca; Lynn Hu (Portfolio Manager): 250-419-8887 or Lynn.Hu@gov.bc.ca

29.0 Finance Charges

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.4.3.1, pdf p. 51

In its response, BC Hydro states that "[t]he WACD Adjustment shown in Schedule 8.0, line 50 is the amount required to adjust the gross finance charges to the amount of eligible borrowing costs used by BC Hydro in calculating the weighted average cost of debt … [t]he WACD Adjustment shown in line 46 is the amount required to adjust the debt amount to the amount of net debt used by BC Hydro in calculating the weighted average cost of debt."

AMPC is seeking clarification of how the WACD Adjustments in Schedule 8.0 were determined.

2.29.1 Please provide supporting calculations for the WACD Adjustments shown in Schedule 8.0, line 46 and 50, for each year from F2015 to F2021.

RESPONSE:

The table below provides the details of the components of the WACD adjustment to net debt balance shown on Schedule 8.0 line 46 of Appendix A to the Evidentiary Update.

Line	$ million	F2015 Actual	F2016 Actual	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Update	F2021 Update
	WACD Adjustment Components:							
1	Sinking Funds	155.1	166.6	179.4	181.8	197.3	201.2	205.9
2	Temporary Investments	39.2	44.4	48.9	41.9	83.9	10.0	10.0
3	Unamortized Net Losses on Discontinued Hedges	(51.5)	(47.6)	(44.2)	(39.1)	(35.7)	(31.1)	(27.9)
4	Miscellaneous Adjustments	(9.5)	(4.2)	(4.0)	(5.8)	(13.9)	-	-
5	**WACD Adjustment - Sch 8.0 Line 46**	**133.3**	**159.2**	**180.1**	**178.8**	**231.6**	**180.2**	**188.0**

The WACD calculations are done in accordance with IFRS. All the components of the WACD adjustments mentioned below relate to items which are excluded from the calculation of the WACD as they are not eligible under IFRS.

Significant variances in the table above relate to the following:

- **Line 1 –The balance in sinking funds increases over time as the debt that they relate to matures in 2026 and 2037;**

- **Line 2 –The balances of temporary investments accounts fluctuate depending on cash flow requirements. Due to their unpredictability, BC Hydro forecasts temporary investments to be $10 million at the end of each fiscal year, thus a drop in fiscal 2020 and fiscal 2021 compared to prior year balances;**

- **Line 3 - The balances of "Unamortized net losses on discontinued hedges" relate to accounting hedges that were discontinued in 2007 when BC Hydro moved from Canadian Generally Accepted Accounting Principles to Prescribed Standards. The debt remains and the accumulated hedging gains and losses are deferred and amortized over the remaining term of the associated debt, thus reducing the outstanding balance every year; and**

- **Line 4 – "Miscellaneous Adjustments" includes adjustments for accrued interest on short-term borrowings. The variances in this line item fluctuate from year to year based on short-term interest rates and the volume of short-term borrowings.**

The table below provides the details of the components of the WACD adjustment to finance charges shown on Schedule 8.0 line 50 of Appendix A to the Evidentiary Update.

Line	**$ million**	**F2015 Actual**	**F2016 Actual**	**F2017 Actual**	**F2018 Actual**	**F2019 Actual**	**F2020 Update**	**F2021 Update**
	WACD Adjustment Components:							
1	Translation Gains/(Losses) on Foreign Currency Denominated Debt (Hedged & Unhedged)	(142.1)	(47.9)	(14.7)	(19.1)	6.6	4.7	1.2
2	Sinking Fund Income after Foreign Exchange Revaluation	26.6	11.4	12.8	2.4	15.4	7.8	7.7
3	Miscellaneous Interest Income/(Expense)	3.6	5.0	11.8	14.7	(19.0)	(6.3)	(7.4)
4	Non-current Pension Costs	(55.0)	(56.9)	(66.0)	(62.0)	(55.9)	36.5	42.2
5	Capitalized Interest During Construction	89.3	81.1	81.2	108.9	130.0	181.5	242.6
6	Sundry Interest Expense	(1.1)	(1.4)	(1.3)	(8.6)	1.0	(0.9)	(0.9)
7	Interest Expense on Deferred Revenue (Seattle City Light)	(4.1)	(2.9)	(2.6)	(4.1)	(22.9)	(25.9)	(28.2)
8	Capital Lease Interest Expense & Accretion	(38.3)	(43.4)	(41.9)	(41.2)	(67.2)	(82.9)	(80.2)
9	Reclassification of Deferred (Gains)/ Losses on Cash Flow Hedges from OCI to Finance Charge	127.2	22.5	11.1	29.7	(8.8)	(11.8)	(11.6)
10	Mark-To-Market Gains/(Losses) on Future Debt Hedges	-	-	187.1	(29.3)	(321.0)	(100.9)	-
11	**WACD Adjustment - Sch 8.0 Line 50**	**6.1**	**(32.5)**	**177.6**	**(8.5)**	**(341.8)**	**1.8**	**165.4**

Significant variances in the table above relate to the following:

- **Line 1 - "Translation Gains / (Losses) on Foreign Currency Denominated Debt (Hedged & Unhedged)" represents the exchange rate fluctuations on the foreign currency denominated debt balances. The amounts fluctuate year-over-year driven by the fluctuations in the exchange rates and volumes of foreign currency denominated debt outstanding;**

- **Line 2 - "Sinking fund income after foreign exchange revaluation" represents the US dollar sinking fund income valued in Canadian dollars. Actual and forecast earnings fluctuate primarily based on changes in the US/Canadian dollar foreign exchange rates;**

- **Line 3 - "Miscellaneous Interest Income/(Expense)" mainly includes interest income on loans issued and vendor financing interest expense. In fiscal 2015 to fiscal 2018 the variances in this line item related only to interest income on loans receivable and fluctuated based on the amounts outstanding. In fiscal 2019, interest expense was added for vendor financings related to the completion of the John Hart project, which resulted in a shift in the balance;**

- **Line 4 - "Non-current Pension Costs" are post-employment benefit related costs. The variances in this line item fluctuate from year to year based on discount rates, investment returns and changes in actuarial assumptions;**

- **Line 5 - "Capitalized Interest during Construction" has been growing over the last five years due to an increase in capital expenditures. It is projected to continue growing in fiscal 2020 and fiscal 2021 due to the Site C project;**

- **Line 6 - "Sundry Interest Expense" represents miscellaneous finance charges that include one-time charges for items such as interest on over-payments by customers. The larger than normal variance in fiscal 2018 of $8.6 million was primarily related to a one-time $7 million interest provision related to a contract dispute;**

- **Line 7 - "Interest Expense on Deferred Revenue (Seattle City Light)" relates to imputed interest on funds that Seattle City Light provided to BC Hydro upfront for delivery of electricity in the future. The larger than normal variance in fiscal 2019 was a result of the adoption of the new revenue recognition accounting standard (IFRS 15) that changed the interest rate from a variable rate to the fixed rate at the inception of the Skagit River Agreement which is higher than the variable rates in recent years;**

- **Line 8 - "Capital Lease Interest Expense & Accretion" includes accretion of provisions associated with asset retirement obligations, First Nations costs and IPP capital leases. An increase in the variance amounts in fiscal 2019 to fiscal 2021 was due to the recognition of additional energy purchase**

contracts with individual power producers as capital leases as part of the adoption of the IFRS 16;

- **Line 9 - "Reclassification of Deferred (Gains)/ Losses on Cash Flow Hedges from OCI to Finance Charges" eliminates gains or losses on the revaluation of BC Hydro's US and Euro denominated debt as intended by cash flow hedges. The year-over-year fluctuation is primarily a function of the changes in the foreign exchange rates of US dollar and Euro to Canadian dollar in a given year; and**

- **Line 10 - "Mark-To-Market Gains/ (Losses) on Future Debt Hedges" are related to unrealized gains or losses that fluctuate with changes in market yield curves (e.g., interest rates) and amounts of hedges outstanding.**

29.0 Finance Charges

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.4.3.1, pdf p. 51

In its response, BC Hydro states that "[t]he WACD Adjustment shown in Schedule 8.0, line 50 is the amount required to adjust the gross finance charges to the amount of eligible borrowing costs used by BC Hydro in calculating the weighted average cost of debt … [t]he WACD Adjustment shown in line 46 is the amount required to adjust the debt amount to the amount of net debt used by BC Hydro in calculating the weighted average cost of debt."

AMPC is seeking clarification of how the WACD Adjustments in Schedule 8.0 were determined.

2.29.2 Please explain any year-over-year changes identified in 29.1 above.

RESPONSE:

Please refer to BC Hydro's response to AMPC IR 2.29.1.

30.0 Finance Charges

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.4.6, pdf pp. 56-57

In its response, BC Hydro states:

> Until the end of fiscal 2019, BC Hydro’s policy had been to update the monthly weighted average cost of debt rate to apply to regulatory accounts only if the actual weighted average cost of debt rate changed from the previous update by more than 25 basis points. As a result, the actual rate used to apply interest to regulatory accounts remained at 4.05 per cent throughout the fiscal 2017 to fiscal 2019 period. In February 2019, BC Hydro amended this policy to remove this 25 basis point threshold and as a result, the rate to apply to regulatory accounts is now updated every month to reflect the actual weighted average cost of debt rate.

AMPC is seeking clarification on this change to BC Hydro's policy.

2.30.1 Please provide a copy of the amended policy referred to.

RESPONSE:

BC Hydro’s amended policy referred to in the preamble to the question is BC Hydro’s Management and Accounting Policies and Procedures 3.1.4B.1 “Calculating Interest During Construction (IDC) Rates Procedure”. The amended document is provided as Attachment 1 to this response. In addition, the version of the document prior to the February 2019 amendment is provided as Attachment 2.

Management and Accounting Policies and Procedures (MAPP)

CALCULATING INTEREST DURING CONSTRUCTION(IDC) RATES PROCEDURE

Ref. #: MAPP 3.1.4B.1 **Effective date:** 2011-Apr-01

Intended readers:	Finance Directors; Financial Analysts
Contact:	Accounting Policy
Document owner position:	Internal Controls & Policy (financial_policies@bchydro.com)

PURPOSE

To describe the procedures for calculating the interest during construction (IDC) rates.

GOVERNING POLICY

MAPP 3.1.4A – Interest During Construction Policy

SCOPE

IDC rates for all actual and forecast expenditures.

PROCEDURE

The IDC rate is calculated as:

$$\left(\frac{\text{Monthly Eligible Borrowing Costs x 12}}{\text{Average Net Debt Outstanding}}\right)$$

All calculations are based on the monthly numbers.

Eligible Borrowing Costs consist of interest on long-term debt, income/loss on interest rate swaps, income/loss on currency swaps, and amortization of department issue discount/expense.

Accounts included: 665200, 665100, 665110, 665115, 665130, 655020, 665140, 665030

Net Debt Outstanding consists of long-term debt balances and unamortized discount and issuance costs. It does not include deferred gain on sale of swaps, mark-to-market of long-term debt balances, and interest payable on short-term notes payable.

Accounts included: 220000, 210000, 220010, 210020, 210300, 210310, 220020, 210040

The Average Net Debt Outstanding is calculated each month as a simple average of the current and the prior month's Net Debt Outstanding.

See current IDC rates at the BC Hydro Common Rates website

Rates used in Financial System

For the purposes of input into the system the monthly IDC rate is determined as follows:

$$\left(\left(\text{IDC Rate}+1\right)^{1/12}-1\right) \times 12$$

The financial system rate is updated monthly based on the prior month's eligible borrowing costs and average net debt (assuming the change in rate is reflective of future trends and not an anomaly in the current period as assessed by the Financial Accounting & Compliance Group).

IDC rate changes in the financial system are applied prospectively to the unfinished construction WIP balance, net of CIA, at the end of the month of the rate change. The rate cannot be applied retroactively.

Rates used for planning

For planning purposes, IDC rates for future years are estimated based on the forecast cost of borrowing as outlined in the BC Hydro Service Plan.

These rates are posted on the BC Hydro Common Rates website and are used in forecasting expenditures when preparing an expenditure authorization request (EAR).

Roles and Responsibility

Forecasting, Revenue & Cost of Energy is responsible for ensuring the correct IDC rates for current and future fiscal years are posted to the BC Hydro Common Rates website.

Financial Accounting & Compliance is responsible for calculating the actual monthly IDC rates.

Financial Processes is responsible for ensuring the correct IDC rate is entered into the Financial system.

Impact/Risk

Using the incorrect IDC rate will result in an over or understatement of net income.

Other Supporting Documentation

No.	Title and document number
[1]	MAPP 3.1.4B.2 Applying IDC Procedure

Examples and Guidelines

No.	Title and document number
[1]	MAPP 3.1.4E.1 FAQ for IDC and Interest Deferral

Next Scheduled Review

The next scheduled review date can be found in the document box in MAPP.

Last Revision

Author / date	Description of changes

Author / date	Description of changes
Graham Shank/Darin Hale/Brenda Debelle Feb 2019	Update for new calculation for IDC Rates
Darin Hale / Brenda Debelle Oct 2018	New Branding and minor wording changes.
Darin Hale Dec 2015	Update account numbers to include euro debt accounts and updated organization and role titles.
Darin Hale June 2012	Revised the next scheduled review information.
Darin Hale Dec 2011	Revised effective date to April 1, 2011 and removed account 665210 from eligible borrowing costs.
Wes Gale Feb 10	Updated for IFRS IDC method (monthly calculation)
Jeremy Jarvis	Implementation of new IDC calculation methodology.
Jeremy Jarvis	Update to reflect change in responsibility and added FAQ.

Management and Accounting Policies and Procedures (MAPP)

CALCULATING IDC RATES PROCEDURE

Ref. #: MAPP 3.1.4B.1 **Effective date:** 2011-Apr-01

Intended readers:	Finance Directors; Financial Analysts
Contact:	Accounting Policy
Document owner position:	Internal Controls & Policy (financial_policies@bchydro.com)

PURPOSE

To describe the procedures for calculating the interest during construction (IDC) rates.

GOVERNING POLICY

MAPP 3.1.4A – Interest During Construction Policy

SCOPE

IDC rates for all actual and forecast expenditures.

PROCEDURE

The weighted average cost of debt (WACD) is calculated as:

$$\left(\frac{\text{Eligible Borrowing Costs x 12}}{\text{Average Net Debt Outstanding}}\right)$$

All calculations are based on the monthly numbers.

Eligible Borrowing Costs consist of interest on long-term debt, income/loss on interest rate swaps, income/loss on currency swaps, and amortization of department issue discount/expense.

Accounts included: 665200, 665100, 665110, 665115, 665130, 655020, 665140, 665030

Net Debt Outstanding consists of long-term debt balances and unamortized discount and issuance costs. It does not include deferred gain on sale of swaps, mark-to-market of long-term debt balances, and interest payable on short-term notes payable.

Accounts included: 220000, 210000, 220010, 210020, 210300, 210310, 220020, 210040

The Average Net Debt Outstanding is calculated each month as a simple average of the current and the prior month's Net Debt Outstanding.

See current IDC rates at the BC Hydro Common Rates website

Rates used in Financial System

For the purposes of input into the system The WACD is adjusted as follows:

$$\left(\left(WACD+1\right)^{1/12}-1\right) \times 12$$

The IDC rate calculated above is based on annual compounding. The financial system rate is updated monthly based on the prior month's eligible borrowing costs and average net debt, if an update is required. The requirement to update the rate will be assessed by the Financial Accounting & Compliance Group based on the following factors:

1. The change in rate is reflective of future trends and not an anomaly in the current period.
2. The change in rate is > 25 basis points.

IDC rate changes in the financial system are applied prospectively to the unfinished construction WIP balance, net of CIA, at the end of the month of the rate change. The rate cannot be applied retroactively.

Rates used for planning

For planning purposes, IDC rates for the next four years are estimated based on the forecast cost of borrowing in the BC Hydro service plan.

These rates are posted on the BC Hydro internal website, and used in forecasting expenditures when preparing an expenditure authorization request.

Roles and Responsibility

Finance – Budgeting & Forecasting is responsible for ensuring the correct IDC rates (for current and the next four fiscal years) are posted to BC Hydro web (BC Hydro Common Rates website).

Finance – Financial Accounting & Compliance is responsible for calculating the Weighted Average Cost of Debt to be used in actual IDC calculations.

Finance – Financial Processes is responsible for ensuring that the correct IDC rate is entered into the Financial system.

Impact/Risk

Using the incorrect IDC rate will result in an over or understatement of income.

Other Supporting Documentation

No.	Title and document number
[1]	MAPP 3.1.4B.2 – Applying IDC

Examples and Guidelines

No.	Title and document number
[1]	MAPP 3.1.4E.1 – FAQ for IDC and Interest Deferral

Next Scheduled Review

The next scheduled review date can be found in the document box in MAPP.

LAST REVISION

Author / date	Description of changes
Darin Hale / Brenda Debelle Oct 2018	New Branding and minor wording changes.
Darin Hale Dec 2015	Update account numbers to include euro debt accounts and updated organization and role titles.
Darin Hale June 2012	Revised the next scheduled review information.
Darin Hale Dec 2011	Revised effective date to April 1, 2011 and removed account 665210 from eligible borrowing costs.
Wes Gale Feb 10	Updated for IFRS IDC method (monthly calculation)
Jeremy Jarvis	Implementation of new IDC calculation methodology.
Jeremy Jarvis	Update to reflect change in responsibility and added FAQ.

30.0 Finance Charges

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.4.6, pdf pp. 56-57

In its response, BC Hydro states:

> Until the end of fiscal 2019, BC Hydro's policy had been to update the monthly weighted average cost of debt rate to apply to regulatory accounts only if the actual weighted average cost of debt rate changed from the previous update by more than 25 basis points. As a result, the actual rate used to apply interest to regulatory accounts remained at 4.05 per cent throughout the fiscal 2017 to fiscal 2019 period. In February 2019, BC Hydro amended this policy to remove this 25 basis point threshold and as a result, the rate to apply to regulatory accounts is now updated every month to reflect the actual weighted average cost of debt rate.

AMPC is seeking clarification on this change to BC Hydro's policy.

2.30.2 Please provide a comparison of actual and approved WACD for F2015 to F2019, including the impact to regulatory accounts if the approved WACD was applied to regulatory account balances.

RESPONSE:

BC Hydro interprets "actual WACD" in the question to mean the calculated monthly WACD rate without the application of the 25 basis point threshold, and interprets "approved WACD" to mean the WACD rate used in applying interest to the regulatory accounts subject to the 25 basis point threshold.

In Attachment 1 to this response, BC Hydro has provided a comparison of the actual monthly weighted average cost of debt rates to the approved monthly weighted average cost of debt rates from the beginning of fiscal 2015 to January 2019, when BC Hydro removed the 25 basis point threshold.

BC Hydro estimates that the impact of using the actual weighted average cost of debt rate, from fiscal 2015 to fiscal 2019, to apply interest to regulatory accounts, would change the interest applied on its regulatory accounts (as applicable) by the amounts presented in the table below.

$ million	F2015	F2016	F2017	F2018	F2019	Total
Increase/(Decrease) in Regulatory Accounts Balance	**1.8**	**0.3**	**(1.1)**	**(1.3)**	**(0.8)**	**(1.1)**

Regardless of the method used to allocate interest to regulatory accounts, BC Hydro's ratepayers only pay for actual interest costs incurred by BC Hydro, and will neither be adversely impacted by, nor benefit from, a higher or lower rate used to allocate interest to regulatory accounts. This is because any differences between forecast and actual finance charges are deferred to the Total Finance Charges Regulatory Account.

Weighted average cost of debt rate			
Month	Actual rate (%)	Approved rate (%)	Difference (%)
April 2014	4.23%	4.05%	0.18%
May 2014	4.11%	4.05%	0.06%
June 2014	4.29%	4.05%	0.24%
July 2014	4.06%	4.05%	0.01%
August 2014	4.19%	4.05%	0.14%
September 2014	4.17%	4.05%	0.12%
October 2014	4.03%	4.05%	(0.02%)
November 2014	4.20%	4.05%	0.15%
December 2014	4.09%	4.05%	0.04%
January 2015	4.17%	4.05%	0.12%
February 2015	4.26%	4.05%	0.21%
March 2015	4.09%	4.05%	0.04%
April 2015	4.17%	4.05%	0.12%
May 2015	3.97%	4.05%	(0.08%)
June 2015	4.19%	4.05%	0.14%
July 2015	4.00%	4.05%	(0.05%)
August 2015	4.18%	4.05%	0.13%
September 2015	4.09%	4.05%	0.04%
October 2015	3.94%	4.05%	(0.11%)
November 2015	4.13%	4.05%	0.08%
December 2015	4.05%	4.05%	(0.00%)
January 2016	4.16%	4.05%	0.11%
February 2016	4.14%	4.05%	0.09%
March 2016	3.83%	4.05%	(0.22%)
April 2016	4.13%	4.05%	0.08%
May 2016	4.00%	4.05%	(0.05%)
June 2016	4.16%	4.05%	0.11%
July 2016	3.95%	4.05%	(0.10%)
August 2016	4.01%	4.05%	(0.04%)
September 2016	4.04%	4.05%	(0.01%)
October 2016	3.87%	4.05%	(0.18%)
November 2016	3.93%	4.05%	(0.12%)
December 2016	3.94%	4.05%	(0.11%)
January 2017	3.93%	4.05%	(0.12%)
February 2017	3.92%	4.05%	(0.13%)
March 2017	3.95%	4.05%	(0.10%)
April 2017	3.94%	4.05%	(0.11%)
May 2017	3.91%	4.05%	(0.14%)
June 2017	3.94%	4.05%	(0.11%)
July 2017	3.92%	4.05%	(0.13%)
August 2017	3.94%	4.05%	(0.11%)
September 2017	3.94%	4.05%	(0.11%)
October 2017	3.95%	4.05%	(0.10%)
November 2017	3.99%	4.05%	(0.06%)
December 2017	4.02%	4.05%	(0.03%)
January 2018	4.03%	4.05%	(0.02%)
February 2018	4.02%	4.05%	(0.03%)
March 2018	4.05%	4.05%	(0.00%)
April 2018	4.03%	4.05%	(0.02%)
May 2018	4.04%	4.05%	(0.01%)
June 2018	4.04%	4.05%	(0.01%)
July 2018	3.97%	4.05%	(0.08%)
August 2018	3.90%	4.05%	(0.15%)
September 2018	3.85%	4.05%	(0.20%)
October 2018	3.89%	4.05%	(0.16%)
November 2018	3.95%	4.05%	(0.10%)
December 2018	3.95%	4.05%	(0.10%)
January 2019	3.88%	4.05%	(0.17%)
February 2019	3.87%	3.87%	0.00%
March 2019	3.89%	3.89%	0.00%

31.0 Demand Side Management

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR 1.5.9, pdf p. 80

In its response, BC Hydro states:

> The LRMC is based on an outdated cost assessment for greenfield wind projects in the Peace River region and it includes BC Hydro's cost to integrate and deliver the energy to the load centre in the Lower Mainland. BC Hydro recognizes that the cost of wind energy has continued to decline since the last update, meaning $105/MWh is an outdated estimate that is too high. BC Hydro plans to update the LRMC in the next IRP.

Reference (ii): Exhibit B-5, BC Hydro Response to BCUC IR 1.175.3, pdf pp. 1974-1976

In its response, BC Hydro states:

> A recent preliminary assessment by BC Hydro estimated the range for wind cost between $54/MWh and $80/MWh, including delivery to the Lower Mainland. This range is consistent with the wind cost estimates in the BC context that have been raised in two recent proceedings.

AMPC is seeking long run marginal cost of energy information in order to understand BC Hydro's demand-side management initiatives.

2.31.1 Is BC Hydro continuing to use the LRMC figure of $105/MWh until it files its next IRP in February 2021? If not, please fully explain your response.

RESPONSE:

BC Hydro's internal decisions on demand side measures are based on the utility cost test at market price, not the LRMC.

The levelized energy LRMC of $105/MWh will continue to be used for regulatory purposes when calculating the total resource cost test required for the Demand-Side Measures Regulation until it is updated in the next IRP. As noted in BC Hydro's response to AMPC IR 1.5.9, BC Hydro recognizes that the cost of wind energy has continued to decline, meaning $105/MWh is an outdated estimate that is too high. BC Hydro will also assess the total resource cost test using sensitivities based on new assessments such as the $54/MWh and $80/MWh range based on preliminary information shown in BC Hydro's response to BCUC IR 1.175.3.

32.0 Competitiveness

Reference (i): Exhibit B-6, BC Hydro Response to BCOAPO IR No. 1.3.3, pdf p. 341

In its response to BCOAPO IR No. 1.3.3, BC Hydro provides a table summarizing its performance measure targets and actual results for 2017/2018. The table identifies BC Hydro's target in 2017/2018 to achieve "1st quartile" competitive rates.

Reference (ii): Exhibit B-1, BC Hydro RRA Application, pdf p. 64

On pdf p. 64, BC Hydro states (emphasis added):

> 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.

AMPC is seeking clarification on BC Hydro's performance targets for industrial customers' rates.

2.32.1 Please confirm that BC Hydro does not have performance targets for industrial rates. If not confirmed, please fully explain your response.

RESPONSE:

The Affordable Bills performance measure in BC Hydro's Service Plan uses residential rates as a benchmark to demonstrate that bills for residential customers are affordable and predictable compared to other major North American utilities. While BC Hydro does not have a Service Plan performance target for industrial rates, our mission is to safely provide reliable, affordable, clean electricity throughout British Columbia.

We recognize that many of our commercial and industrial customers face challenging market conditions and are conscious of the impact that any bill increase may have. Accordingly, the Application reflects careful planning and prioritization to achieve the right balance between investment and low rates. Based on the Evidentiary Update, the approvals BC Hydro is seeking would result in a rate decrease of 0.99 per cent in fiscal 2021.

33.0 Rate Smoothing Regulatory Account

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR 1.22.2, pdf p. 280

In its response regarding its continued collection of the $45 million Rate Smoothing Account debt servicing cost for each test year, BC Hydro states that "Section 4(1)(c) of Direction No. 8 provides that the BCUC must not disallow for any reason the recovery in rates of the costs incurred by BC Hydro with respect to debt servicing costs on amounts borrowed related to the Rate Smoothing Regulatory Account approved by Order No. G-48-14."

Reference (ii): Exhibit B-6, BC Hydro Response to BCSEA IR 1.22.2, pdf p. 623

In this IR, BCSEA asked BC Hydro to explain what it meant by "write-off" in the following statement:

> “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 ...”

BC Hydro's response was as follows:

> 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. BC Hydro expensed the entire $1.044 billion Rate Smoothing Regulatory Account balance to operating expenses at December 31, 2018. Further information can be found on pages 2, 10 and 30 of BC Hydro’s 2018/19 Third Quarter Report.
>
> Additionally, as BC Hydro ceased using the Rate Smoothing Regulatory Account at the end of the third quarter of fiscal 2019, $92 million forecast to be transferred to the Rate Smoothing Regulatory Account during the fourth quarter of fiscal 2019 will be recorded as expenses in fiscal 2019.
>
> In the context of the passage included the preamble, “write-off” means that the total amount forecast to be transferred to the Rate Smoothing Regulatory Account by the end of fiscal 2019, which would have been recovered from ratepayers in future periods, is a cost borne by the Government of B.C. as BC Hydro’s shareholder, and will no longer be recovered from ratepayers. This amount totals $1.136 billion ($1.044 billion plus $92 million).

Reference (iii):Exhibit B-5, BC Hydro Response to BCUC IR 1.140.1, pdf pp. 1615-1616

In setting out BC Hydro's calculation of the annual debt servicing costs for fiscal 2020 and fiscal 2021 associated with the write-off of the balance of the Rate Smoothing Regulatory Account, BC Hydro states as follows:

> As a result of the write-off of the balance of the Rate Smoothing Regulatory Account, BC Hydro will collect $1.136 billion less cash from ratepayers than if the total forecast transfers to the account had continued to the end of fiscal 2019 and had been recovered in customer rates in future periods. BC Hydro's debt is therefore $1.136 billion higher than it otherwise would be, all other things equal.
>
> BC Hydro uses its forecast weighted average cost of debt to calculate the annual debt servicing costs associated with this debt.

$ millions	Reference Appendix A	F2020	F2021
Forecast weighted average cost of debt	Sch 8.0, L52	3.88%	3.82%
Debt related to the Rate Smoothing Regulatory Account		$1,136	$1,136
Annual debt servicing costs		$44.1	$43.4

> Please refer to BC Hydro's response to BCUC IR 1.140.5, where we explain that our debt is managed on a portfolio basis and that we do not specifically allocate debt repayments to specific drivers of debt. For the purpose of the calculation above, we are not assuming any repayment of the debt related to the Rate Smoothing Regulatory Account during the fiscal 2020 to fiscal 2021 test period.

Reference (iv):British Columbia Hydro and Power Authority 2018/19 Third Quarter Report, p. 30

At p. 30, BC Hydro describes the writing off of the Rate Smoothing Regulatory Account as follows:

> As at December 31, 2018, the entire balance of the Rate Smoothing Regulatory Account (RSRA) was expensed as BC Hydro determined that collection of the RSRA was no longer probable based on information received from the Province. This resulted in an operating expense of $1.04 billion during the three month and nine month periods ended December 31, 2018. The operating expense was comprised of the $815 million balance in the account as at April 1, 2018 and $229 million

deferred in the account during the nine-month period ended December 31, 2018 prior to the write-off.

AMPC would like to better understand BC Hydro's claims regarding the debt servicing costs for debt related to the Rate Smoothing Regulatory Account.

2.33.1 Please confirm that ratepayers are continuing to pay the carrying cost of the 1.136 billion in debt that has already been paid. Please fully explain.

RESPONSE:

BC Hydro confirms that ratepayers are continuing to pay the carrying cost of the $1.136 billion in debt related to the Rate Smoothing Regulatory Account, but it is not correct that the debt has already been paid. Since the balance of the Rate Smoothing Regulatory Account has been written-off, the balance that was in the account will not be recovered from ratepayers. Instead, the write-off is a cost that was borne by the shareholder through a reduction in actual net income, and there has been no cash payment from the shareholder to cover the debt associated with the Rate Smoothing Regulatory Account.

Please refer to BC Hydro’s response to BCUC IR 1.140.5, where we explain that our debt is managed on a portfolio basis and that we do not specifically allocate debt repayments to specific drivers of debt. The incremental debt associated with the Rate Smoothing Regulatory Account will be repaid over time.

33.0 Rate Smoothing Regulatory Account

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR 1.22.2, pdf p. 280

In its response regarding its continued collection of the $45 million Rate Smoothing Account debt servicing cost for each test year, BC Hydro states that "Section 4(1)(c) of Direction No. 8 provides that the BCUC must not disallow for any reason the recovery in rates of the costs incurred by BC Hydro with respect to debt servicing costs on amounts borrowed related to the Rate Smoothing Regulatory Account approved by Order No. G-48-14."

Reference (ii): Exhibit B-6, BC Hydro Response to BCSEA IR 1.22.2, pdf p. 623

In this IR, BCSEA asked BC Hydro to explain what it meant by "write-off" in the following statement:

> “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 ...”

BC Hydro's response was as follows:

> 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. BC Hydro expensed the entire $1.044 billion Rate Smoothing Regulatory Account balance to operating expenses at December 31, 2018. Further information can be found on pages 2, 10 and 30 of BC Hydro’s 2018/19 Third Quarter Report.
>
> Additionally, as BC Hydro ceased using the Rate Smoothing Regulatory Account at the end of the third quarter of fiscal 2019, $92 million forecast to be transferred to the Rate Smoothing Regulatory Account during the fourth quarter of fiscal 2019 will be recorded as expenses in fiscal 2019.
>
> In the context of the passage included the preamble, “write-off” means that the total amount forecast to be transferred to the Rate Smoothing Regulatory Account by the end of fiscal 2019, which would have been recovered from ratepayers in future periods, is a cost borne by the Government of B.C. as BC Hydro’s shareholder, and will no longer be recovered from ratepayers. This amount totals $1.136 billion ($1.044 billion plus $92 million).

Reference (iii):Exhibit B-5, BC Hydro Response to BCUC IR 1.140.1, pdf pp. 1615-1616

In setting out BC Hydro's calculation of the annual debt servicing costs for fiscal 2020 and fiscal 2021 associated with the write-off of the balance of the Rate Smoothing Regulatory Account, BC Hydro states as follows:

> As a result of the write-off of the balance of the Rate Smoothing Regulatory Account, BC Hydro will collect $1.136 billion less cash from ratepayers than if the total forecast transfers to the account had continued to the end of fiscal 2019 and had been recovered in customer rates in future periods. BC Hydro's debt is therefore $1.136 billion higher than it otherwise would be, all other things equal.
>
> BC Hydro uses its forecast weighted average cost of debt to calculate the annual debt servicing costs associated with this debt.
>
> | $ millions | Reference Appendix A | F2020 | F2021 |
> |---|---|---|---|
> | Forecast weighted average cost of debt | Sch 8.0, L52 | 3.88% | 3.82% |
> | Debt related to the Rate Smoothing Regulatory Account | | $1,136 | $1,136 |
> | Annual debt servicing costs | | $44.1 | $43.4 |
>
> Please refer to BC Hydro's response to BCUC IR 1.140.5, where we explain that our debt is managed on a portfolio basis and that we do not specifically allocate debt repayments to specific drivers of debt. For the purpose of the calculation above, we are not assuming any repayment of the debt related to the Rate Smoothing Regulatory Account during the fiscal 2020 to fiscal 2021 test period.

Reference (iv):British Columbia Hydro and Power Authority 2018/19 Third Quarter Report, p. 30

At p. 30, BC Hydro describes the writing off of the Rate Smoothing Regulatory Account as follows:

> As at December 31, 2018, the entire balance of the Rate Smoothing Regulatory Account (RSRA) was expensed as BC Hydro determined that collection of the RSRA was no longer probable based on information received from the Province. This resulted in an operating expense of $1.04 billion during the three month and nine month periods ended December 31, 2018. The operating expense was comprised of the $815 million balance in the account as at April 1, 2018 and $229 million

deferred in the account during the nine-month period ended December 31, 2018 prior to the write-off.

AMPC would like to better understand BC Hydro's claims regarding the debt servicing costs for debt related to the Rate Smoothing Regulatory Account.

2.33.2 Please confirm that, during 2020 – 2021, BC Hydro will pay down the principal of some of the debt in its portfolio other than the $1.136 billion in debt identified as related to the RSRA.

RESPONSE:

Not confirmed. BC Hydro has some debt maturing in the test period and will repay this debt. However, please refer to BC Hydro’s response to BCUC IR 1.140.5, where we explain that our debt is managed on a portfolio basis and that we do not specifically allocate debt repayments to specific drivers of debt.

It should also be noted that BC Hydro’s total debt is forecast to increase during the test period and therefore any debt repayments made during the test period will be more than offset by new debt issuances.

34.0 Operating Costs

Reference (i): Exhibit B-6, BC Hydro Response to AMPC 1.3.10, pdf p. 35

In its response, BC Hydro attributes higher school taxes to a change to BC Assessment's replacement cost model for transmission and distribution lines.

AMPC is seeking further information on which lines are affected and the impact of those changes to BC Hydro's Application.

2.34.1 When was BC Assessment's updated replacement cost model implemented, and what is the basis for the change? Please provide a copy of the updated replacement cost model, including any relevant documents specifying which transmission and distribution lines were affected.

RESPONSE:

BC Assessment has advised BC Hydro that it intends to implement its updated replacement cost model for the 2021 assessment roll, which will be issued on January 1, 2021 and will impact BC Hydro's school taxes, commencing in fiscal 2021. The new replacement cost model will be used to value all transmission lines and distribution lines owned by BC Hydro as well as those owned by all other electric utilities.

BC Assessment has also advised that the change is part of its overall initiative to review the replacement cost models for the linear assets of all types of companies, including electric power, railway, pipeline and telecommunication companies. BC Assessment has further advised BC Hydro that it reviews its valuation models on a periodic basis in order to ensure that the property assessments reflect current costs and market conditions.

The requested details and documents are the property of BC Assessment, have not yet been implemented and have only been provided to BC Hydro in draft as part of confidential discussions. BC Hydro requested consent to provide the information in confidence to the BCUC. BC Assessment has declined to provide consent at this time, but has advised that they are targeting to have a report available by mid-September 2019.

34.0 Operating Costs

Reference (i): Exhibit B-6, BC Hydro Response to AMPC 1.3.10, pdf p. 35

In its response, BC Hydro attributes higher school taxes to a change to BC Assessment's replacement cost model for transmission and distribution lines.

AMPC is seeking further information on which lines are affected and the impact of those changes to BC Hydro's Application.

2.34.2 Please confirm that BC Assessment consulted or engaged with BC Hydro with regard to the change to BC Assessment’s replacement cost model for transmission and distribution lines, prior to the change. For example, did BC Hydro appeal or challenge the change? Please describe the substance and procedure of the consultation or engagement that occurred and BC Hydro’s position regarding the changes.

RESPONSE:

Confirmed. BC Assessment has consulted with BC Hydro since June 2015, and continues to do so as the process is not yet complete.

BC Hydro was provided with the opportunity to review the changes and we have challenged many of the assumptions, inputs and variables in the replacement cost model via meetings and e-mail exchanges. BC Assessment provided draft copies of engineering reports, spreadsheet analyses, etc. to BC Hydro and also requested cost details for our recently completed transmission line projects from BC Hydro.

BC Assessment has provided evidence and documentation to support its updated assessment valuation rates and BC Hydro is not appealing or challenging the change. In order to minimize the immediate financial impact, we have requested that BC Assessment exercise its discretion to phase in the new rates over three years, which is the maximum period allowed under legislation. The forecast submitted in the Application assumed a three-year phased implementation commencing on January 1, 2021 which will impact our school taxes commencing in fiscal 2021.

34.0 Operating Costs

Reference (i): Exhibit B-6, BC Hydro Response to AMPC 1.3.10, pdf p. 35

In its response, BC Hydro attributes higher school taxes to a change to BC Assessment's replacement cost model for transmission and distribution lines.

AMPC is seeking further information on which lines are affected and the impact of those changes to BC Hydro's Application.

2.34.3 How did the model change? Please explain in detail, and provide any relevant documentation or summaries of the changes.

RESPONSE:

BC Assessment advised that it was necessary to update its replacement cost model, which had not been reviewed for more than 20 years, in order to reflect current market conditions, construction costs and quantities for materials and labour, engineering standards, right-of-way requirements and depreciation rates.

The valuation methodology and assumptions are now more clearly defined and detailed than in the previous model. BC Assessment commissioned an independent engineering firm to provide a detailed report of current replacement cost estimates instead of relying on company-reported replacement costs as was done in the past.

As noted in BC Hydro’s response to AMPC IR 2.34.2, BC Hydro is not able to share any further details on the model at this time.

34.0 Operating Costs

Reference (i): Exhibit B-6, BC Hydro Response to AMPC 1.3.10, pdf p. 35

Reference (ii): Exhibit B-6, BC Hydro Responses to AMPC IRs 1.3.10 & 1.3.11, pdf pp 35-36

BC Hydro states that taxes are forecast to increase during the test years due to the following:

- **General inflationary increases to Provincial tax revenue requirements (for School Taxes) and municipal tax revenue requirements (for Grants in Lieu). The test period forecast assumes that the Government of B.C. and municipalities will continue to implement annual tax increases of approximately 3 per cent to 4 per cent on the assessed values of land, buildings and electric system assets;**
- **Increases in taxes for Metro Vancouver land parcels due to the continuing trend of higher than inflationary increases in assessed values by BC Assessment;**
- **An increased BC Hydro taxable asset base, as new assets are constructed and placed in-service in fiscal 2020 and fiscal 2021. Significant examples include the John Hart Generating Station Replacement, West Kamloops Substation, and the Ruskin Dam and Powerhouse Upgrade;**
- **Increased forecast domestic electricity sales, which will result in a corresponding increase in Grants in Lieu costs, which are paid based on 1 per cent of these sales; and**
- **Higher School Taxes due to significant increases in the assessed values of transmission and distribution lines as a result of BC Assessment's updated replacement cost model for these assets.**

BC Hydro then provides the following individual factor impact assessment forecast for the test years:

Taxes ($ million)

F2019 Forecast	**242.2**
Increased property values & increased taxation rates[1]	6.7
Completion of new capital projects	1.1
Increased domestic electricity sales	1.8
Decrease in IPP capital leases due to change in IFRS accounting treatment	(2.0)
F2020 Forecast	**249.8**
Increased property values & increased taxation rates[1]	5.4
Increase in assessed value of transmission & distribution lines	4.0
Completion of new capital projects	1.2
Increased domestic electricity sales	1.8
F2021 Forecast	**262.2**

Note 1: Property values and increased rates are closely linked, and together result in the general inflationary increases experienced each year.

AMPC would like to better understand the factors that BC Hydro says are leading to higher tax and grant in lieu payments being required.

2.34.4 Please confirm that the amount BC Hydro is permitted to pay in grants in lieu is subject to a cap. If confirmed, please describe the cap and amount that BC Hydro would be permitted to pay in grants in lieu if the cap were not in effect.

RESPONSE:

BC Hydro is authorized by the Government of B.C., through Orders in Council, to pay three different types of grants-in-lieu of taxes. Each of these types is subject to limits that BC Hydro cannot exceed, as follows:

1. **Grants: Land & Buildings – For each taxation year, BC Hydro is authorized to pay grants-in-lieu which do not exceed the amount equal to the general municipal, rural and/or regional district taxes that would have been levied in the previous year in relation to all BC Hydro fee-owned land and building properties;**

2. **Grants: 1 per cent of Revenues – For each taxation year, BC Hydro is authorized to pay grants-in-lieu which do not exceed 1 per cent of gross revenues from electricity sales within all municipal and rural jurisdictions in British Columbia during the previous fiscal year; and**

3. Grants: Generation Facilities – For each taxation year, BC Hydro is authorized to pay grants-in-lieu for our generating facilities to specified municipalities and regional districts in the amounts listed by the Government of B.C. under the prevailing Order In Council.

If the limits were not in effect, BC Hydro would be subject to whatever alternate policy the Government of B.C. enacted in regards to the taxation of BC Hydro. If the Government of B.C. did not enact an alternate policy and there were no limits, then BC Hydro would be similar to other taxpayers in that it would be subject to whatever rates each municipality chose to impose on our taxable property, which is primarily in the Utilities class. It is not possible to know what the amounts would be in this scenario.

34.0 Operating Costs

Reference (i): Exhibit B-6, BC Hydro Response to AMPC 1.3.10, pdf p. 35

Reference (ii): Exhibit B-6, BC Hydro Responses to AMPC IRs 1.3.10 & 1.3.11, pdf pp 35-36

BC Hydro states that taxes are forecast to increase during the test years due to the following:

- **General inflationary increases to Provincial tax revenue requirements (for School Taxes) and municipal tax revenue requirements (for Grants in Lieu). The test period forecast assumes that the Government of B.C. and municipalities will continue to implement annual tax increases of approximately 3 per cent to 4 per cent on the assessed values of land, buildings and electric system assets;**
- **Increases in taxes for Metro Vancouver land parcels due to the continuing trend of higher than inflationary increases in assessed values by BC Assessment;**
- **An increased BC Hydro taxable asset base, as new assets are constructed and placed in-service in fiscal 2020 and fiscal 2021. Significant examples include the John Hart Generating Station Replacement, West Kamloops Substation, and the Ruskin Dam and Powerhouse Upgrade;**
- **Increased forecast domestic electricity sales, which will result in a corresponding increase in Grants in Lieu costs, which are paid based on 1 per cent of these sales; and**
- **Higher School Taxes due to significant increases in the assessed values of transmission and distribution lines as a result of BC Assessment's updated replacement cost model for these assets.**

BC Hydro then provides the following individual factor impact assessment forecast for the test years:

Taxes ($ million)

F2019 Forecast	**242.2**
Increased property values & increased taxation rates[1]	6.7
Completion of new capital projects	1.1
Increased domestic electricity sales	1.8
Decrease in IPP capital leases due to change in IFRS accounting treatment	(2.0)
F2020 Forecast	**249.8**
Increased property values & increased taxation rates[1]	5.4
Increase in assessed value of transmission & distribution lines	4.0
Completion of new capital projects	1.2
Increased domestic electricity sales	1.8
F2021 Forecast	**262.2**

Note 1: Property values and increased rates are closely linked, and together result in the general inflationary increases experienced each year.

AMPC would like to better understand the factors that BC Hydro says are leading to higher tax and grant in lieu payments being required.

2.34.5 Please provide additional details and documents to support BC Hydro's forecast that the Government of BC and municipalities will implement annual tax increases between 3-4% on the assessed values of land, buildings and electric system assets. In your response, please consider and explain the role of municipal mill rates and, for grants in lieu, the cap related to electricity sold.

RESPONSE:

BC Hydro’s forecast that the Government of B.C. and municipalities will implement tax increases of 3 per cent to 4 per cent annually is based on recent actual increases. The table below shows the annual increases in taxation years 2016, 2017 and 2018 for BC Hydro’s payments for school taxes and the grants in lieu for our fee-owned land and buildings. Only these payments are directly impacted by the general inflationary increases for Provincial and municipal tax revenue requirements. The annual percentage increases of BC Hydro’s actual payment expenses for the past three years are consistent with our forecast for future payment expenses.

The table below also shows the actual 2019 taxation year payments which reflect an annual increase of 3.9 per cent, which is consistent with our forecast range of 3 per cent to 4 per cent.

Taxation Year	2019 ($ million)	2018 ($ million)	2017 ($ million)	2016 ($ million)
School taxes	137.4	134.5	130.8	126.3
Grants In Lieu for Land and Buildings	44.9	40.9	36.7	35.0
Total	182.3	175.4	167.5	161.3
% Increase over Prior Year	3.9%	4.7%	3.8%	4.2%

Municipal mill rates are not the key driver of the increases. Grants-in-lieu are directly linked to municipal tax increases which are driven by general inflationary increases for municipal revenue requirements (i.e. municipal budgets) rather than by municipal mill rates. The mill rates for many municipalities have decreased in recent years but the taxes are still increasing as property assessed values have increased. School tax increases are driven by general inflationary increases for Provincial revenue requirements (i.e. the Government of B.C. budget).

The cap related to electricity sold impacts only the Grants-in-Lieu based on 1 per cent of Revenues, and is not linked to municipal and Provincial annual tax increases.

35.0 Capital Expenditures

Reference: Exhibit B-5, BC Hydro Response to BCUC IR 1.115.1, pdf pp. 1282-1284

In its response, BC Hydro identifies the intended CPCN filing date for the following five extension projects:

- Metro North Transmission
- West Kelowna Transmission/Westbank Substation Upgrade
- Northwest Substation Upgrade
- Peace Region to Kelly Lake 500kV Transmission Reinforcement
- Mainwaring Substation Upgrade

BC Hydro provides CPCN filing dates for most of the projects but has not provided the forecast start dates of construction or forecast in-service dates for these five projects.

Reference: Exhibit B-6, BC Hydro Response to BCOAPO IR 1.47.2, pdf p. 525

In its response, BC Hydro explains which of its Key Business Units are responsible for delivering capital projects. It states:

> Other than the Capital Infrastructure Project Delivery Business Group, Power System capital investments (excluding the Site C Project), are delivered by the Operations Business Group, specifically the Program and Contract Management KBU and the Distribution Design and Customer Connections KBU. The Program and Contract Management KBU delivers lower risk and high volume projects and programs. The Distribution Design and Customer Connections KBU delivers lower risk and tariff driven customer connections.

AMPC is seeking additional information on the staffing, timing and processing for system extension requests in order to better understand the steps and timing involved.

2.35.1 Which KBU deals with service extension requests?

RESPONSE:

BC Hydro interprets this question's reference to service extension requests as referring to interconnection requests for new industrial loads. Two KBUs are

responsible for managing a new industrial load request through the interconnection processes:

1. **The Interconnections and Shared Assets KBU (part of the Integrated Planning Business Group), which is responsible for all transmission interconnection requests and major distribution load interconnection requests. The guideline for major distribution load interconnection requests is a new distribution load request that has anticipated demand over 5 MVA or estimated connection costs in excess of $1 million;[1] and**

2. **The Distribution Design and Customer Connections KBU (part of the Operations Business Group) which is responsible for other new distribution load requests (i.e., usually less than 5 MVA and/or less than $1 million in estimated connection costs).**

Capital projects resulting from a new load interconnection request may be implemented by the following KBUs:

- **Project Delivery KBU (Capital Infrastructure Project Delivery Business Group);**
- **Program and Contract Management KBU (Operations Business Group); or**
- **Distribution Design and Customer Connections KBU (Operations Business Group).**

A capital project is allocated to a particular KBU for implementation based on the service voltage (transmission or distribution), the estimated cost of infrastructure required, and project risks and complexity.

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[1] **In section 6.4.15 of the Application, we indicated the dollar threshold as $2 million. This threshold is currently reduced to $1 million.**

35.0 Capital Expenditures

Reference: Exhibit B-5, BC Hydro Response to BCUC IR 1.115.1, pdf pp. 1282-1284

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BC Hydro provides CPCN filing dates for most of the projects but has not provided the forecast start dates of construction or forecast in-service dates for these five projects.

Reference: Exhibit B-6, BC Hydro Response to BCOAPO IR 1.47.2, pdf p. 525

In its response, BC Hydro explains which of its Key Business Units are responsible for delivering capital projects. It states:

> Other than the Capital Infrastructure Project Delivery Business Group, Power System capital investments (excluding the Site C Project), are delivered by the Operations Business Group, specifically the Program and Contract Management KBU and the Distribution Design and Customer Connections KBU. The Program and Contract Management KBU delivers lower risk and high volume projects and programs. The Distribution Design and Customer Connections KBU delivers lower risk and tariff driven customer connections.

AMPC is seeking additional information on the staffing, timing and processing for system extension requests in order to better understand the steps and timing involved.

2.35.2 Does BC Hydro have different Business Groups for service extension requests by large power users compared to smaller users? Please explain how this Business Group operates and which customer classes and sectors are served.

RESPONSE:

BC Hydro interprets this question's reference to service extension requests by large power users as referring to interconnection requests for new industrial loads.

Please refer to BC Hydro's response to AMPC IR 2.35.1 where we explain that the Integrated Planning Business Group and the Operations Business Group manage the interconnection of new load customers, and we also discuss the type of requests managed by KBUs in each of these Business Groups.

35.0 Capital Expenditures

Reference: Exhibit B-5, BC Hydro Response to BCUC IR 1.115.1, pdf pp. 1282-1284

In its response, BC Hydro identifies the intended CPCN filing date for the following five extension projects:

- Metro North Transmission
- West Kelowna Transmission/Westbank Substation Upgrade
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- Mainwaring Substation Upgrade

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Reference: Exhibit B-6, BC Hydro Response to BCOAPO IR 1.47.2, pdf p. 525

In its response, BC Hydro explains which of its Key Business Units are responsible for delivering capital projects. It states:

> Other than the Capital Infrastructure Project Delivery Business Group, Power System capital investments (excluding the Site C Project), are delivered by the Operations Business Group, specifically the Program and Contract Management KBU and the Distribution Design and Customer Connections KBU. The Program and Contract Management KBU delivers lower risk and high volume projects and programs. The Distribution Design and Customer Connections KBU delivers lower risk and tariff driven customer connections.

AMPC is seeking additional information on the staffing, timing and processing for system extension requests in order to better understand the steps and timing involved.

2.35.3 Have there been any staffing changes within the last five years, or proposed for the test years for the KBU that handles large power users’ service extension requests?

RESPONSE:

BC Hydro interprets this question's reference to large power users' service extension requests as referring to interconnection requests for new industrial loads.

Please refer to BC Hydro's response to AMPC IR 2.35.1 where we explain which Business Groups and KBUs manage the interconnection of new load customers and the type of requests each KBU manages.

There have been staffing changes in each of these KBUs over the last five years and changes are expected in the test period. As explained in section 5.6.3 of Chapter 5 of the Application, FTE increases since fiscal 2012 have been driven by BC Hydro's capital plan. Table 5-12 on page 5-43 of the Application shows the FTEs by Business Group in the test period. For details on the staffing levels for fiscal 2017 to fiscal 2021 in the KBUs that support interconnection requests for new industrial loads, please refer to the Application as follows:

- **Table 5A-13 for Interconnections and Shared Assets KBU (Integrated Planning Business Group);**
- **Table 5B-5 for Project Delivery KBU (Capital Infrastructure Project Delivery Business Group); and**
- **Table 5C-5 for Program and Contract Management KBU (Operations Business Group).**

35.0 Capital Expenditures

Reference: Exhibit B-5, BC Hydro Response to BCUC IR 1.115.1, pdf pp. 1282-1284

In its response, BC Hydro identifies the intended CPCN filing date for the following five extension projects:

- Metro North Transmission
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- Mainwaring Substation Upgrade

BC Hydro provides CPCN filing dates for most of the projects but has not provided the forecast start dates of construction or forecast in-service dates for these five projects.

Reference: Exhibit B-6, BC Hydro Response to BCOAPO IR 1.47.2, pdf p. 525

In its response, BC Hydro explains which of its Key Business Units are responsible for delivering capital projects. It states:

> Other than the Capital Infrastructure Project Delivery Business Group, Power System capital investments (excluding the Site C Project), are delivered by the Operations Business Group, specifically the Program and Contract Management KBU and the Distribution Design and Customer Connections KBU. The Program and Contract Management KBU delivers lower risk and high volume projects and programs. The Distribution Design and Customer Connections KBU delivers lower risk and tariff driven customer connections.

AMPC is seeking additional information on the staffing, timing and processing for system extension requests in order to better understand the steps and timing involved.

2.35.4 Please provide copies of any internal policies governing service extension requests and generally explain the steps that BC Hydro undertakes when processing a service extension request, including average timelines to complete each step. If BC Hydro follows different steps or timelines for different types of customers, please fully explain.

RESPONSE:

BC Hydro interprets the reference to service extension requests in the question as referring to interconnection requests for new industrial loads.

Industrial Load interconnections follow either the Large Industrial Connection (Transmission Service) process or the Large Industrial Connection (Distribution Service) process. Details of the steps and typical timelines for each of these processes are described on BC Hydro's website (Industrial Connections webpages) at: https://app.bchydro.com/accounts-billing/electrical-connections/industrial-connections.html.

The main documents governing industrial interconnection requests are Tariff Supplement No. 6 for connections to the transmission system and section 8 of the Electric Tariff for distribution voltage connections.

To support Tariff Supplement No. 6, BC Hydro created a queue management business practice which is used to determine the order for initiating load interconnection studies, cost allocation for infrastructure required to supply a new load, and customer's obligations for remaining in the queue. The queue business practice is available on BC Hydro's website (Business Practice for Load Interconnection Queue Management) at: https://app.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/00-2014-11-18-queue-management-business-practice.pdf .

35.0 Capital Expenditures

Reference: Exhibit B-5, BC Hydro Response to BCUC IR 1.115.1, pdf pp. 1282-1284

In its response, BC Hydro identifies the intended CPCN filing date for the following five extension projects:

- Metro North Transmission
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- Peace Region to Kelly Lake 500kV Transmission Reinforcement
- Mainwaring Substation Upgrade

BC Hydro provides CPCN filing dates for most of the projects but has not provided the forecast start dates of construction or forecast in-service dates for these five projects.

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In its response, BC Hydro explains which of its Key Business Units are responsible for delivering capital projects. It states:

> Other than the Capital Infrastructure Project Delivery Business Group, Power System capital investments (excluding the Site C Project), are delivered by the Operations Business Group, specifically the Program and Contract Management KBU and the Distribution Design and Customer Connections KBU. The Program and Contract Management KBU delivers lower risk and high volume projects and programs. The Distribution Design and Customer Connections KBU delivers lower risk and tariff driven customer connections.

AMPC is seeking additional information on the staffing, timing and processing for system extension requests in order to better understand the steps and timing involved.

2.35.5 How many requests for system extension has BC Hydro received per year from large power users in each of the last five years? Please provide the average request to completion time for system extension requests by large power users by year for the last five years.

RESPONSE:

BC Hydro interprets this question's reference to system extensions from large power users as interconnection requests for new large industrial loads.

As explained in BC Hydro's response to BCUC IR 2.35.4, interconnection requests for new large industrial loads will either follow the Large Industrial Connection (Transmission Service) process or the Large Industrial Connection (Distribution service) process. Data below include only those formal requests that have gone through BC Hydro's interconnection process. In the normal course of business, BC Hydro receives and manages a large number of informal inquiries and/or requests that are discontinued midway; these are not included in the summary below.

Large Industrial Connection (Transmission Service)

BC Hydro does not track the total duration of transmission service load interconnection requests from first contact to in-service date as there are many factors outside of BC Hydro's control that affect the timeline and cause delays, such as changes to customer's requirements and data. However, since 2016 BC Hydro has tracked the number and average duration in days of System Impact Studies and Facilities Studies completed as well as the number of transmission load interconnection request projects that reach in-service in any given year. This information is provided in following table:

	F2017		F2018		F2019		F2020*	
	Total Number	Average Duration	Total Number	Average Duration	Total Number	Average Duration	Total Number	Average Duration
System Impact Studies	10	131	18	84	21	109	9	131
Facilities Studies	3	176	7	215	4	276	0	0
Projects reaching in-service	9	N/A	11	N/A	19	N/A	1	N/A

Notes:

*** Fiscal 2020 data cover the period from April 1, 2019 to July 31, 2019.**

Large Industrial Connection (Distribution Service)

For major distribution interconnection requests, since 2016 BC Hydro has tracked the number and average duration in days of studies in the Identification Study Phase and Definition Detailed Design Phase as well as the number of transmission load interconnection request projects that reach in-service in any given year. This information is provided in the following table:

	F2017		F2018		F2019		F2020*	
	Total Number	Average Duration	Total Number	Average Duration	Total Number	Average Duration	Total Number	Average Duration
Identification Study Phase	14	66	41	60	26	47	16	39
Definition Detailed Design Phase	10	389	6	263	14	387	5	480
Projects reaching in-service	9	N/A	6	N/A	10	N/A	1	N/A

Notes:

*** Fiscal 2020 data cover the period from April 1, 2019 to July 31, 2019.**

Identification Study Phase is from receipt of an acceptable major distribution load connection application to project cost quotation.

Definition Detailed Design Phase is from Definition Funding approval to quotation of Implementation costs.

35.0 Capital Expenditures

Reference: Exhibit B-5, BC Hydro Response to BCUC IR 1.115.1, pdf pp. 1282-1284

In its response, BC Hydro identifies the intended CPCN filing date for the following five extension projects:

- Metro North Transmission
- West Kelowna Transmission/Westbank Substation Upgrade
- Northwest Substation Upgrade
- Peace Region to Kelly Lake 500kV Transmission Reinforcement
- Mainwaring Substation Upgrade

BC Hydro provides CPCN filing dates for most of the projects but has not provided the forecast start dates of construction or forecast in-service dates for these five projects.

Reference: Exhibit B-6, BC Hydro Response to BCOAPO IR 1.47.2, pdf p. 525

In its response, BC Hydro explains which of its Key Business Units are responsible for delivering capital projects. It states:

> Other than the Capital Infrastructure Project Delivery Business Group, Power System capital investments (excluding the Site C Project), are delivered by the Operations Business Group, specifically the Program and Contract Management KBU and the Distribution Design and Customer Connections KBU. The Program and Contract Management KBU delivers lower risk and high volume projects and programs. The Distribution Design and Customer Connections KBU delivers lower risk and tariff driven customer connections.

AMPC is seeking additional information on the staffing, timing and processing for system extension requests in order to better understand the steps and timing involved.

2.35.6 How does the current waiting time for completion of system extension requests to compare to (i) the 2000 – 2015 period; and (ii) any neighbouring or other jurisdictions BC Hydro benchmarks its performance to.

RESPONSE:

BC Hydro interprets "waiting times for completion of the extension request" in the question to refer to the total duration of the interconnection process for transmission interconnection load requests.

BC Hydro does not track the total duration of the transmission load interconnection process from first contact to in-service date. BC Hydro began tracking the average duration of completed System Impact Studies and Facilities Studies in 2016. As a result, BC Hydro does not have the data available to provide the requested comparison of current waiting times to those in the 2000 to 2015 period. Please refer to BC Hydro's response to AMPC IR 2.35.5 for details of the statistics available for interconnection activities that BC Hydro tracks, as well as factors that impact the timeline of requests.

Benchmarking the total duration of interconnection related activities and timelines is challenging because interconnection processes differ between jurisdictions. Common practice across comparable utilities is to publish targets or average timelines for the key interconnection process activities. It is important to note that utilities define the stages of transmission load interconnection in different ways and with different terms. A comparison of target / average timelines across utilities and BC Hydro is summarized below.

Interconnection Activity	BC Hydro	AESO	Sask Power	Hydro One
System Impact Studies or equivalent	6 to 9 months	37 weeks (9 months)	4 to 12 months	4 to 7 months
Facilities Studies or equivalent	6 to 9 months	52 weeks (12 months)	6 to 18 months	5 to 8+ months
Implementation	No target set	No target set	6 to 18 months	1 to 2+ years

35.0 Capital Expenditures

Reference: Exhibit B-5, BC Hydro Response to BCUC IR 1.115.1, pdf pp. 1282-1284

In its response, BC Hydro identifies the intended CPCN filing date for the following five extension projects:

- Metro North Transmission
- West Kelowna Transmission/Westbank Substation Upgrade
- Northwest Substation Upgrade
- Peace Region to Kelly Lake 500kV Transmission Reinforcement
- Mainwaring Substation Upgrade

BC Hydro provides CPCN filing dates for most of the projects but has not provided the forecast start dates of construction or forecast in-service dates for these five projects.

Reference: Exhibit B-6, BC Hydro Response to BCOAPO IR 1.47.2, pdf p. 525

In its response, BC Hydro explains which of its Key Business Units are responsible for delivering capital projects. It states:

> Other than the Capital Infrastructure Project Delivery Business Group, Power System capital investments (excluding the Site C Project), are delivered by the Operations Business Group, specifically the Program and Contract Management KBU and the Distribution Design and Customer Connections KBU. The Program and Contract Management KBU delivers lower risk and high volume projects and programs. The Distribution Design and Customer Connections KBU delivers lower risk and tariff driven customer connections.

AMPC is seeking additional information on the staffing, timing and processing for system extension requests in order to better understand the steps and timing involved.

2.35.7 Does BC Hydro have any internal targets for timing related to customer service requests? If not, why not? If so, please provide details.

RESPONSE:

BC Hydro interprets the reference to customer service requests in the question as referring to interconnection requests for new industrial loads. As noted in BC Hydro's response to BCUC IR 2.35.4, large industrial connections will either follow the Large Industrial Connection (Transmission Service) or the Large Industrial Connection (Distribution service) process.

BC Hydro sets internal targets each year for:

- **System Impact Studies and Facilities Studies related to new transmission load interconnection requests**

  These targets are based on the average duration of the studies, as timelines for each type of study vary significantly depending on the size, location, type of load, type of interconnection, and the complexity of the system upgrades required to serve the new transmission load interconnection request. The targeted average duration for System Impact Studies is 150 days and the targeted average duration for Facilities Studies is 180 days.

- **Planning Studies and Facilities Studies (definition detailed design) related to new major distribution load interconnection requests**

  These targets are based on the average duration of the studies, as timelines for each type of study vary significantly depending on the size, location, type of load, type of interconnection, and the complexity of the system upgrades required to serve the new major distribution load interconnection request. The targeted average duration for Planning Studies is 60 days and the targeted average duration for Facilities Studies is 365 days.

We do not set targets for the duration of the implementation phase of new interconnection requests, as the infrastructure required to connect and serve each new load request is unique to that request.

35.0 Capital Expenditures

Reference: Exhibit B-5, BC Hydro Response to BCUC IR 1.115.1, pdf pp. 1282-1284

In its response, BC Hydro identifies the intended CPCN filing date for the following five extension projects:

- Metro North Transmission
- West Kelowna Transmission/Westbank Substation Upgrade
- Northwest Substation Upgrade
- Peace Region to Kelly Lake 500kV Transmission Reinforcement
- Mainwaring Substation Upgrade

BC Hydro provides CPCN filing dates for most of the projects but has not provided the forecast start dates of construction or forecast in-service dates for these five projects.

Reference: Exhibit B-6, BC Hydro Response to BCOAPO IR 1.47.2, pdf p. 525

In its response, BC Hydro explains which of its Key Business Units are responsible for delivering capital projects. It states:

> Other than the Capital Infrastructure Project Delivery Business Group, Power System capital investments (excluding the Site C Project), are delivered by the Operations Business Group, specifically the Program and Contract Management KBU and the Distribution Design and Customer Connections KBU. The Program and Contract Management KBU delivers lower risk and high volume projects and programs. The Distribution Design and Customer Connections KBU delivers lower risk and tariff driven customer connections.

AMPC is seeking additional information on the staffing, timing and processing for system extension requests in order to better understand the steps and timing involved.

2.35.8 Has BC Hydro taken or planned to take any steps to reduce waiting times for system extension requests for large power users? Please fully explain your response.

RESPONSE:

BC Hydro interprets the reference to system extension requests for large power users in the question as referring to interconnection requests for new industrial loads.

Please refer to BC Hydro's response to AMPC IR 2.35.6 where we provide a comparison of our average timelines for transmission load interconnection to target / average timelines for other utilities. BC Hydro has taken several steps to improve interconnection timelines for new industrial load interconnection requests. Specifically we have:

- **Engaged in WorkSmart initiatives based on lean principles to:**
  - **Streamline the project hand over process from the Integrated Planning Business Group to the Capital Infrastructure Project Delivery Business Group; and**
  - **Implement an expedited transmission interconnection process for new load requests at existing sites that meet the following conditions: the site already has transmission service, there is capacity available, and no system reinforcements are required;**
- **Implemented a process allowing customers to design and build transmission taps on BC Hydro's behalf in order to give the customer more control over the project schedule and costs;**
- **Restructured the Capital Infrastructure Project Delivery Business Group to create a project delivery team that focuses on interconnection projects and scaling the delivery process;**
- **Developed performance metrics for interconnection study timelines to track performance against targets, to identify trends and to evaluate the effectiveness of interconnection process improvement; and**
- **Initiated three ex-plan projects to ensure that BC Hydro is able to provide transmission services in the timeline required for customer need and desire to electrify their operations. Please refer to BC Hydro's response to BCUC IR 2.254.2 for additional information on these projects.**

BC Hydro continues to look for interconnection process improvement opportunities and is open to feedback and ideas from industry, so that we can continue to advance initiatives that will improve the process for both new load customers and BC Hydro.

36.0 Capital Expenditures

Reference: Exhibit B-5, BC Hydro Response to BCUC IR 107.1, Attachment 1, pdf p. 1056

In its response, BC Hydro provides an updated table that identifies 28 projects that were placed in-service from March 1, 2018 to March 31, 2019 inclusive with an Expected Cost of $5 million or greater. The table identifies the following projects with cost variances over 5%:

- Kamloops Substation (17%)
- Arnott Capacity Upgrade (15%)
- Campbell River Substation Capacity Upgrade (29%)
- Fernie – Substation Upgrade (19%)
- 37-60/138kV CB Replacement F14/F15 (58%)
- 60 kV CB Replacement - F16/17 (8%)

AMPC is seeking additional information on the reasons for and recovery of cost variances on these projects.

2.36.1 For each of the projects listed above, please confirm that the cost variances on these projects were added to rate base and recovered on the basis they were prudently incurred costs. If not confirmed, please fully explain your response.

RESPONSE:

BC Hydro confirms that actual costs of capital projects were added to rate base and recovered in rates, on the basis that they were prudently incurred.

As noted in section 6.2.1.2 of Chapter 6 in the Application, 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. 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. These underspend variances reduce the actual rate base compared to what was planned.

36.0 Capital Expenditures

Reference: Exhibit B-5, BC Hydro Response to BCUC IR 107.1, Attachment 1, pdf p. 1056

In its response, BC Hydro provides an updated table that identifies 28 projects that were placed in-service from March 1, 2018 to March 31, 2019 inclusive with an Expected Cost of $5 million or greater. The table identifies the following projects with cost variances over 5%:

- Kamloops Substation (17%)
- Arnott Capacity Upgrade (15%)
- Campbell River Substation Capacity Upgrade (29%)
- Fernie – Substation Upgrade (19%)
- 37-60/138kV CB Replacement F14/F15 (58%)
- 60 kV CB Replacement - F16/17 (8%)

AMPC is seeking additional information on the reasons for and recovery of cost variances on these projects.

2.36.2 For each of the projects listed above, explain why the actual cost exceeded the expected cost, including what modifications were required to the project and the date when BC Hydro first knew or reasonably could have known of the need for modifications.

RESPONSE:

Kamloops Substation

The actual cost of $51.6 million exceeds the expected cost of $44.1 million for this project for the following reasons:

- **There was an increase in the construction costs compared to plan, due to underestimated construction market rates;**
- **Actual ground conditions differed from expected conditions resulting in changes to the detailed design of the retaining walls;**
- **There was a change from wood H-Frame structures to steel monopoles in Kenna Cartwright Park to minimize the right-of-way width in the park;**
- **The proposed microwave tower in Kenna Cartwright Park needed to be relocated to minimize a new road in the park. The new microwave tower**

location was further up the mountain requiring taller towers and larger foundations than planned; and

- **There were equipment and material cost increases due to design specification changes and price and currency exchange rate increases.**

All of these modifications were identified during Implementation Phase.

<u>Arnott Capacity Upgrade</u>

The actual cost of $39.5 million exceeded the expected cost of $34.3 million for this project for the following reasons:

- **Higher than estimated engineering, construction management and construction costs as the final designs were more complex than estimated; and**
- **Higher than estimated equipment and material costs due to market conditions.**

All of these modifications were identified during Implementation Phase.

<u>Campbell River Substation Capacity Upgrade</u>

The forecasted actual cost of $32.7 million exceeds the expected cost of $25.4 million for this project for the following reasons:

- **Unforeseen geotechnical issues: a liquefiable layer was not identified until the geotechnical investigations were undertaken in the Implementation phase. This led to design changes that resulted in additional costs and schedule delay. BC Hydro's practice is now to undertake geotechnical investigations during the Definition Phase;**
- **Underestimated resources and duration of staging and construction: additional civil work was required to accommodate physical constraints caused by working in an operating substation. These additional complexities added to quantities and effort required to perform the work adding about six months to the construction schedule. This was identified in the Implementation phase; and**
- **Additional scope: including distribution scope (which reduced the overall costs on a future/planned project), a new retaining wall (to improve maintenance access to the new transformer), two replacement station transformers (as the existing ones were at the end of their lives), and telecom scope (which added wireless telephone connection).**

All of these modifications were identified during Implementation Phase.

Fernie Substation Upgrade Project

The actual cost of $28.0 million exceeded the expected cost of $23.5 million for this project for the following reasons:

- **Higher than estimated engineering, construction management, and construction costs. The approved costs were based on the preliminary designs completed during the Definition phase of the project. However, the detailed designs completed during the Implementation phase were more complex and required additional design efforts as well as longer construction periods; and**
- **Equipment and material costs were higher due to market conditions as well as change in the currency exchange rates.**

All of these modifications were identified during Implementation Phase.

37 60/138kV CB Replacement Fiscal 2014/2015

The actual cost of $16.8 million exceeds the expected cost of $10.6 million for this project for the following reasons:

- **Construction costs were higher due to market conditions: the construction cost estimate was based on historical data from similar past projects; due to changing market conditions this cost estimate was not achievable based on a competitively bid construction contract; and**
- **Contrary to plan, all existing cables could not be reused, PCB contamination was found within each Circuit Breaker or surrounding soils, and not all footings could be reused.**

All of these modifications were identified during Implementation Phase.

60 kV CB Replacement - Fiscal 2016/2017

The actual cost of $6.1 million exceeds the expected cost of $5.7 million for this project due to construction delays at all four substations (Walters, Canreed, Lake Buntzen #1, and Steeples) that were part of this project. These delays occurred during construction which spanned 2017 to 2018. The reasons for the delays are as follows:

- **Walters substation feeds a key account/customer. A power outage to all customers fed from Walters was required to perform the work. To avoid significantly impacting the operations of the key account/customer, the**

project delayed the construction to coordinate the required power outage with a scheduled plant outage at the key account, resulting in additional project costs

- **At Canreed, there was a schedule delay due to Construction Services resource constraints and complex staging due to the compact structure (limits of approach issue). Real Time Operations (RTO) outage constraints further delayed the construction schedule. In addition, this site had cables that did not match cable routing diagrams. For safety reasons, a more costly hydro-vac truck had to be used for excavations;**

- **At Lake Buntzen No. 1, construction of the last circuit breaker was delayed to coordinate with the shutdown of two key accounts/customers. This caused additional mobilization and demobilization costs; and**

- **At Steeples, there was a construction delay due to outage constraints from Real Time Operations. In addition, there was a minor scope change which involved the relocation of two existing Voltage Transformers to improve the functionality and maintainability of the existing substation.**

37.0 Capital Expenditures

Reference: Exhibit B-5, BC Hydro Response to BCUC IR 107.2, pdf pp. 1058-1062

In its response to BCUC IR 107.2, BC Hydro identifies the factors that contributed to the cost variances on the following projects:

- Dawson Creek/Chetwynd Area Transmission
- Interior to Lower Mainland Transmission
- Northwest Transmission Line
- Hugh Keenleyside Spillway Gate Upgrade
- Big Bend Substation

BC Hydro attributes the cost variances to multiple factors, including:

- Late design and scope changes, in some cases post contract award;
- Underestimating the resources required, time required and work scope;
- Unexpected geotechnical conditions;
- Challenges with achieving competitive tender processes; and
- Delays and extended project duration.

AMPC is seeking additional information on the recovery of cost variances on these projects.

2.37.1 For each of the projects listed above, please confirm that cost variances on these projects were added to rate base and recovered on the basis they were prudently incurred costs. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed.

38.0 Capital Expenditures

Reference: Exhibit B-5, BC Hydro Response to BCUC IR 161.6, pdf p. 1817

On p. 1817, BC Hydro identifies project write-offs of $27.3 million in F2018. It identifies a $13.6 million write-off for the Terrace to Kitimat Transmission Project and a $13.7 million write-off for other project/partial write-offs.

AMPC is seeking additional information to assess the reasonableness of these project write-offs.

2.38.1 For the Terrace to Kitimat Transmission project, please provide a list of:

(a) the costs that have already been incurred in the Terrace to Kitimat Transmission project. In this list, please identify any measures taken by BC Hydro to redirect costs already incurred towards other projects (e.g., repurposing materials already purchased or redirecting contractors/labour already engaged); and
(b) the costs to refurbish the existing line. Please also provide the associated business case.

RESPONSE:

The costs already incurred on the Terrace to Kitimat Transmission project are set out in the table below.

Item	Cost ($ millions)
Design (transmission line, access roads, and vegetation clearing design)	**4.9**
Environment (wildlife, fish, and vegetation assessments)	**4.2**
Project Management (general management, scheduling, cost control, estimating, and other)	**2.2**
Indigenous Relations (First Nations consultation and engagement)	**1.7**
Permits, Properties, and Stakeholder Engagement (Crown Land application, property and access agreements, municipal governments and public stakeholder meetings)	**0.4**
Centerline Survey, Helipad Installation, and Road Upgrades	**0.4**

The work associated with the costs incurred for this project could not be applied to the refurbishment of the existing line because the project would have been a new line, in a new corridor. As a result, the amount redirected to refurbishment of the existing line was limited to $0.2 million.

Refurbishment of the existing line is being undertaken as part of the Wood Structure Replacement Program, which involves standard replacements using standard BC Hydro methods and equipment. Accordingly, the refurbishment work for this line does not have its own business case. The cost is expected to be approximately $15 million to $20 million.

38.0 Capital Expenditures

Reference: Exhibit B-5, BC Hydro Response to BCUC IR 161.6, pdf p. 1817

On p. 1817, BC Hydro identifies project write-offs of $27.3 million in F2018. It identifies a $13.6 million write-off for the Terrace to Kitimat Transmission Project and a $13.7 million write-off for other project/partial write-offs.

AMPC is seeking additional information to assess the reasonableness of these project write-offs.

2.38.2 For the remaining $13.7 million write-off, please provide a list of the other project write-offs and partial write-offs that occurred and identify any measures taken by BC Hydro to redirect costs already incurred towards other projects (e.g., repurposing materials already purchased or redirecting contractors/labour already engaged).

RESPONSE:

The table below provides a breakdown of the project write-offs and partial project write-offs over $100,000 that are included in the remaining $13.7 million write-off amount referenced in the question.

The amounts shown in the table are the net expenditures that no longer have future value. Before amounts are written off, there is a thorough review of the expenditures incurred to determine whether any of the expenditures can be carried forward with a new project alternative or used on an alternate project. In addition, if any materials have been acquired, they are either returned to the vendor or disposed at market values.

Name of Project	F2018 Actual ($M)
Peace Canyon Flood Discharge Gates Reliability Improvement	3.9
Schedule Dispatch Mobility	2.9
2L90 Thermal Upgrade (See Note 1)	1.2
Takla Landing (NI-NEW-287)	1.0
Copper Conductor Replacements F17 (See Note 2)	0.5
60L285/288/292 Rating Restore & Refurbish	0.4
MIN Junction Box Replacements	0.4
60L344 Rating Restoration and Refurbishment	0.4
LMS Parking Lot & Entrance	0.3
Catalyst Powell River G13	0.3
Chetwynd Mechanical Pulp	0.3
NI-NEW-116r DAW 25F53 Relocate MVA	0.2
NI-NEW-104 CWD 25F61 U/G Heavily Treed	0.2
NI-NC-151 CHF: New CHF UG feeder egress	0.2
PCM Program w VVO - 7a - WHY	0.2
PCM Upgrade Program w/VVO - 6g - RBW	0.2
11 projects with write-offs of $100,000 or less	1.1
Total	**13.7**

Notes

1. **$109,000 of costs (i.e., portions of design, planning, estimating, safety, environment, survey and properties documents) were transferred to the Bridge River Transmission project. Purchased materials that could be re-stocked were returned for credit.**
2. **$259,000 of design costs associated with a PLS-CADD model used to identify circuit deficiencies were transferred to the F2019 Copper Conductor Replacement project.**

39.0 Other Revenue Requirement Items – Voltage Conversion Projects

Reference: Exhibit B-5, BC Hydro Response to BCUC IR 1.158.1, pdf p. 1768

In its response, BC Hydro confirms that BC Hydro incurred costs related to infrastructure rights prior to F2019, these customer-owned equipment upgrades did not commonly occur and were not material.

AMPC is seeking additional information on these voltage conversion projects in order to assess the reasonableness of the projects and understand what customer contributions BC Hydro is seeking.

2.39.1 Please explain why these voltage conversion projects are being undertaken now despite "not commonly occur[ring]" in the past and being "not material".

RESPONSE:

To clarify, BC Hydro's response to BCUC IR 1.158.1 states that customer-owned equipment upgrades (infrastructure rights) did not commonly occur and were not material prior to fiscal 2019.

Please refer to BC Hydro's response to BCUC IR 2.260.1 which shows an increase in the number of active voltage conversion projects from fiscal 2014 to fiscal 2019. These projects are being undertaken increasingly in the dense urban areas where there is often no available space along the street corridors to place utility equipment. When there is no space for utility equipment, BC Hydro works with customers to identify opportunities to upgrade customer-owned equipment (which incur costs related to infrastructure rights) to avoid more costly utility infrastructure upgrades along the street corridor.

Please refer to BC Hydro's response to BCOAPO IR 2.146.1 which describes the primary reasons for undertaking voltage conversion and how it is cost effective as it utilizes existing infrastructure as an alternative to building more costly new feeders and civil infrastructure.

Please refer to BC Hydro's response to CEC IR 1.75.4 which states when the primary voltage needs to be converted to a higher voltage (e.g., 12 kV to 25 kV), all equipment and all customer service connections must be able to operate at the higher voltage.

Please refer to BC Hydro's response to CEC IR 1.75.6 which describes the impacts of not upgrading customer equipment.

39.0 Other Revenue Requirement Items – Voltage Conversion Projects

Reference: Exhibit B-5, BC Hydro Response to BCUC IR 1.158.1, pdf p. 1768

In its response, BC Hydro confirms that BC Hydro incurred costs related to infrastructure rights prior to F2019, these customer-owned equipment upgrades did not commonly occur and were not material.

AMPC is seeking additional information on these voltage conversion projects in order to assess the reasonableness of the projects and understand what customer contributions BC Hydro is seeking.

2.39.2 Please provide BC Hydro's estimated customer contributions for these projects for F2020-F2021.

RESPONSE:

Please refer to Table 8-4 on page 8-7 of Chapter 8 of the Application. The estimated customer contributions for fiscal 2020 to fiscal 2021 are the amounts shown as Infrastructure Rights. The amounts are provided in the table below.

($ million)	F2020 Plan	F2021 Plan
C11650 Infrastructure Rights	**20.5**	**12.8**

40.0 Biomass

Reference: **Exhibit B-5, BC Hydro Response to BCUC IR No. 1.15.2, pdf p. 230**

In its response, BC Hydro stated:

> 80 per cent, in aggregate of historical energy volumes and 100 per cent of the aggregate capacity volumes are renewed for the Biomass EPA. BC Hydro also states that "BC Hydro assumes that 100 per cent of the capacity will be available to serve winter peak demand because the reductions in energy, where applicable, are expected to come in other months of the year (e.g., freshet)."

AMPC is seeking clarification on the effects of renewing the Biomass EPA on customers.

2.40.1 How are customers compensated for the reduction in energy purchases if BC Hydro still uses 100% of the capacity of the Biomass EPAs?

RESPONSE:

BC Hydro customers are not compensated for a "reduction in energy purchases" under the Biomass Energy Program. BC Hydro will pay an energy price to IPPs in accordance with the terms of each EPA; there will be no separate payment for capacity. Please refer to BC Hydro's response to BCSEA IR 1.11.6 for a discussion of how costs for EPAs under the Biomass Energy Program will result in lower costs relative to the original agreements.

Please refer to Rate Schedule 1828[1] which provides the rates applicable, including the demand charge and energy charge, to BC Hydro customers who have entered into a contract with BC Hydro under the Biomass Energy Program.

[1] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/electric-tariff/bchydro-electric-tariff.pdf

41.0 Depreciation

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR No. 1.23.1, pdf p. 288; BC Hydro Response to AMPC IR No. 1.23.7, pdf p. 313; BC Hydro Response to AMPC IR No. 1.23.7.1, pdf p. 314

On pdf p. 288, BC Hydro states as follows:

> BC Hydro currently has no indication that asset life expectations have changed in a significant way that would have a material impact on depreciation expense. Therefore, we believe that the cost and effort of performing the study would outweigh the benefits.

AMPC seeks to understand BC Hydro's response.

2.41.1 How much did the 2005 depreciation study cost to conduct?

RESPONSE:

BC Hydro paid $161,025 to Gannett Fleming for conducting the depreciation study plus internal effort by BC Hydro to support its preparation.

41.0 Depreciation

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR No. 1.23.1, pdf p. 288; BC Hydro Response to AMPC IR No. 1.23.7, pdf p. 313; BC Hydro Response to AMPC IR No. 1.23.7.1, pdf p. 314

On pdf p. 288, BC Hydro states as follows:

BC Hydro currently has no indication that asset life expectations have changed in a significant way that would have a material impact on depreciation expense. Therefore, we believe that the cost and effort of performing the study would outweigh the benefits.

AMPC seeks to understand BC Hydro's response.

2.41.2 Did BC Hydro assess at any point whether asset life expectancies from the 2005 depreciation study remain valid? If not, why not? If yes, please (i) confirm the investigation was done on an asset class specific basis, and (ii) provide details of the asset class life expectancy assessment analysis.

RESPONSE:

In fiscal 2010, BC Hydro conducted a review of asset class useful lives as part of the pending adoption of the Prescribed Standards. The depreciation review was conducted at the same time as the preparation of the Gannett Fleming Report on IFRS Componentization included in Appendix G of the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application.

Asset classes with net book value balances greater than $20 million at December 31, 2009 and information technology asset classes with net book values of greater than $5 million were included in the review. The review consisted of discussions with business group representatives and Gannett Fleming to identify whether there were indications that the useful lives of asset classes differed from the lives determined in the previous study.

Attachment 1 to this response provides a summary of the asset classes reviewed, the current useful life, the potential revised life based on the review and review comments for each asset class.

Potential useful life changes were identified for some asset classes. BC Hydro performed a recalculation of fiscal 2011 depreciation expense based on the current and the potential revised useful lives to determine whether there would be

a material change in BC Hydro depreciation expense. The net change in depreciation expense was a reduction of less than $1 million as shown in Attachment 2 to this response. As the net change was less than $1 million and the potential changes were not definitive as they were based only on a review (and not substantiated by a study, which would be needed to make changes), BC Hydro's depreciation expense was considered to be appropriately stated.

Depreciation Useful Life Review

February/March 2010

Profile ID	Profile ID Descriptions	Catalogue section	BG Response	Asset Type	Average Useful Life (Current)	Salvage % (Current)	Average Useful Life (Revised)	Salvage (Revised)	Depreciation Review Comments
C25203	C25203 - Tower, Lattice / Asthetic	Transmission/Distribution	BCTC	M	65	0	75	0	Implemented a new program to apply a coating to towers. Planning to implement cathodic protection (prevents/slows future rusting) around bases of towers to protect the steel in the ground. New actuals data that wasn't previously available. 75-year average life makes sense based on BCTC experience and new protection programs.
C55303	C55303 – Cable,Submarine > 60 kV	Transmission/Distribution	BCTC	I	45	0	45	0	Low likelihood of environmental legislation that would require the line to be removed Low likelihood that an event (such as an anchor strike) would damage the cable enough to require the replacement of the cable. Low volume of assets (15 submarine cables). Sim model cannot forecast accurately due to low volume of units. No indicators suggesting a life change.
C55101	C55101 - Conductor, Overhead > 60 kV	Transmission/Distribution	BCTC	M	60	0	60	0	No indicators suggesting a life change.
C65001	C65001 – Panels/Cubicles, P&C	Switchyard Equipment	BCTC	M	20	0	20	0	No indicators suggesting a life change.
C25202	C25202 – Pole Structures > 60 kV	Transmission/Distribution	BCTC	M	50	0	60	0	Waterloo study suggests longer life than 50 years. Historical data is suggesting that the life is longer than 50 years. Historical data does not reflect that there is some backlog of pole replacements due to financial constraints. Cross-arms have been pulled out as separate components. Newer poles are second and third generation growth which will lead to shorter life than first growth poles. Transmission poles are all cedar poles versus Distribution poles that are pine and cedar. Lives are impacted by location – shorter lives in coastal/rainforest areas, longer lives in drier/desert areas.
C54104	C54104 – Breaker,Gas(Sf6), 69 To 500 kV	Switchyard Equipment	BCTC	I	45	0	45	0	No indication that life needs to change.

Profile ID	Profile ID Descriptions	Catalogue section	BG Response	Asset Type	Average Useful Life (Current)	Salvage % (Current)	Average Useful Life (Revised)	Salvage (Revised)	Depreciation Review Comments
C55401	C55401 – Buswork & Station Conductor	Switchyard Equipment	BCTC	M	60	0	60	0	No indication that life needs to change.
C25301	C25301 – Foundations	Site /Structures/Improvements	BCTC	M	40	0	40	0	No indication that life needs to change.
C25101	C25101 – Structure, Support, Steel	Site /Structures/Improvements	BCTC	M	65	0	65	0	No indication that life needs to change.
C52104	C52104 – Transformer, Power - < 100Mva	Switchyard Equipment	BCTC	I	45	0	55	0	PCB issue not causing early retirement, can drain the oil and continue to use the transformer body. Larry is seeing lives in industry moving higher. Larry's clients are not using greater than 45 years. Based on BCTC model data Larry agreed that 55 years would be appropriate. All transformers are redundant so they are only being used at 50 per cent capacity maximum, mainly at 33 per cent of capacity. Physical deterioration tends to occur when transformers are used at high capacity. Load growth/increased capacity is a factor in early retirements rather than physical deterioration Some owned by Generation, Generation transformers tend to have shorter lives because they are used at a high percentage of capacity
C52106	C52106 – Transformer, Power, Comp Pool	Switchyard Equipment	BCTC	I	45	0	55	0	PCB issue not causing early retirement. Oil can be drained and transformer body can be re-used. Larry is seeing lives in industry moving higher. Make the same 55-year life as C52104. Some owned by Generation, Generation transformers tend to have shorter lives because they are used at a high percentage of capacity
C56001	C56001 – Insulators	Switchyard Equipment	BCTC	M	55	0	55	0	No indication that life needs to change.
C52103	C52103 – Transformer, Power - > 100Mva	Switchyard Equipment	BCTC	I	40	0	50	0	PCB issue not causing early retirement. Oil can be drained and transformer body can be re-used. Larger transformers have different load characteristics than lower voltage transformers. The higher voltage run at higher loads and will deteriorate faster. Larry is seeing lives in industry moving higher. BCTC data suggests a longer life.
C55302	C55302 – Cable,Underground >60 kV	Transmission/Distribution	BCTC	I	40	0	45	0	Manufacturers suggest a life of 40 years Historical data suggests average life of greater than 40 years. More appropriate life is 45 years.

Profile ID	Profile ID Descriptions	Catalogue section	BG Response	Asset Type	Average Useful Life (Current)	Salvage % (Current)	Average Useful Life (Revised)	Salvage (Revised)	Depreciation Review Comments
C52101	C52101 - Transformer,Generator,Stepup	Switchyard Equipment	EARG	I	40	0	40	0	No indication that life needs to change.
C54201	C54201 - Use Individual Disconnect Caus	Switchyard Equipment	BCTC	M	40	0	40	0	No indication that life needs to change
C54102	C54102 - Breaker,Gas(Sf6)12 / 25 kV	Switchyard Equipment	BCTC	I	30	0	30	0	No indication that life needs to change.
C62001	C62001 - Fire Protection System	Switchyard Equipment	BCTC	M	25	0	25	0	No indication that life needs to change.
C55501	C55501 - Grounding Systems	Switchyard Equipment	BCTC	M	40	0	40	0	No indication that life needs to change.
C52302	C52302 - Reactor, Dry Type	Switchyard Equipment	BCTC	I	40	0	40	0	No indication that life needs to change.
C25502	C25502 - Ductbanks > 60 kV	Transmission/Distribution	BCTC	I	50	0	45	0	Ductbanks for transmission are having to be replaced due to changes in transmission size cables (oil filled cables are smaller in diameter than new types of cables). Ductbank life should be the same as the underground cables. Life should be changed to 45 years.
C68302	C68302 - Radio,Microwave, Digital	Communication	BCTC	I	35	0	25	0	Three components of electronic equipment – channel bank, radio and multiplex. Primarily radios in this profile ID. Radio and multiplex should have a similar life. A life of 25 years would be reasonable
C57001	C57001 - Arrestor, Surge	Switchyard Equipment	BCTC	M	30	0	30	0	Per BCTC 30 year life is reasonable.
C53101	C53101 - Capacitor, Shunt	Switchyard Equipment	BCTC	I	30	0	30	0	No indication that life needs to change.
C52301	C52301 - Reactor, Oil	Switchyard Equipment	BCTC	I	25	0	35	0	BCTC suggests life should be higher. Reactors run at full load all of the time. Until 10 years ago, there were a high number of failures but the failures have decreased. The life of reactors should be similar to generator transformers. A 35 year life is a more appropriate life.
C25401	C25401 - Ducts & Trenches	Site /Structures/Improvements	BCTC	M	50	0	50	0	No indication that life needs to change.

Profile ID	Profile ID Descriptions	Catalogue section	BG Response	Asset Type	Average Useful Life (Current)	Salvage % (Current)	Average Useful Life (Revised)	Salvage (Revised)	Depreciation Review Comments
C22005	C22005 - Building, Composite Pool	Site /Structures/Improvements	Corp	I	60	0	60	0	Move to install geothermal systems in new buildings. From Larry's experience, the life of these systems is 20 years. Move to installing green roofs on new buildings. Life of green roofs is uncertain at this time as they are quite a new concept. Larry suggested that the new green roofs be classified within the existing roof Profile ID. The life will be re-assessed during next depreciation study. No indication that life of buildings needs to change.
C22002	C22002 – Commercial, Concrete Or Steel	Site /Structures/Improvements	Corp	I	50	0	50	0	See comments above for Building Composite pool. No indication that life of buildings needs to change.
C80302	C80302 - Software, Mainframe	Computers	Corp	I	10	0	10	0	No indication that life needs to change.
C80303	C80303 - Software, Mid-Range Systems	Computers	Corp	I	5	0	5	0	No indication that life needs to change.
C21001	C21001 - Dam, Embankment / Concrete	Site /Structures/Improvements	EARG	I	100	0	100	0	No indicators that a life change is required.
C22003	C22003 - Powerhouse, Integral With Dam	Site /Structures/Improvements	EARG	I	100	0	100	0	No indicators that a life change is required.
C41007	C41007 - Turbine, Hydro, Comp. Pool	Generating Equipment	EARG	I	50	0	50	0	No indicators that a life change is required.
C42003	C42003 - Generator, Composite Pool	Generating Equipment	EARG	I	50	0	50	0	No indicators that a life change is required.
C23001	C23001 - Spillway, Separate From Dam	Site /Structures/Improvements	EARG	I	75	0	75	0	No indicators that a life change is required.
C42001	C42001 - Coils, Stator	Generating Equipment	EARG	I	30	0	30	0	No indicators that a life change is required.
C23201	C23201 - Penstock, Steel	Site /Structures/Improvements	EARG	I	75	0	75	0	No indicators that a life change is required.
C42002	C42002 - Rotor, Generator	Generating Equipment	EARG	I	50	0	50	0	No indicators that a life change is required.
C23202	C23202 - Penstock, Concrete	Site /Structures/Improvements	EARG	I	100	0	100	0	No indicators that a life change is required.
C23101	C23101 - Intake Structure, Power	Site /Structures/Improvements	EARG	I	100	0	100	0	No indicators that a life change is required.

Profile ID	Profile ID Descriptions	Catalogue section	BG Response	Asset Type	Average Useful Life (Current)	Salvage % (Current)	Average Useful Life (Revised)	Salvage (Revised)	Depreciation Review Comments
C23401	C23401 - Tailrace	Site /Structures/Improvements	EARG	I	100	0	100	0	No indicators that a life change is required.
C24201	C24201 - Tunnels	Site /Structures/Improvements	EARG	I	100	0	100	0	No indicators that a life change is required.
C23604	C23604 - Gate	Site /Structures/Improvements	EARG	I	40	0	40	0	No indicators that a life change is required.
C41001	C41001 - Runner / Water Wheel	Generating Equipment	EARG	I	50	0	50	0	No indicators that a life change is required.
C22001	C22001 - Plant, Concrete Or Steel	Site /Structures/Improvements	EARG	I	50	0	50	0	No indicators that a life change is required.
C23603	C23603 - Hoist, Gate	Site /Structures/Improvements	EARG	I	55	0	55	0	No indicators that a life change is required.
C24101	C24101 - Sluiceway, Separate From Dam	Site /Structures/Improvements	EARG	I	100	0	100	0	No indicators that a life change is required.
C23801	C23801 - Cranes	Site /Structures/Improvements	EARG	I	60	0	60	0	No indicators that a life change is required.
C82550	C82550 - Tools/Work Equipment, Misc	Vehicles/Work Equipment	EARG	M	15	0	15	0	No indicators that a life change is required.
C24001	C24001 - Navigation Locks	Site /Structures/Improvements	EARG	I	100	0	100	0	No indicators that a life change is required.
C24301	C24301 - Slope Stabilization	Site /Structures/Improvements	EARG	M	100	0	100	0	No indicators that a life change is required.
C23605	C23605 - Gates, Embedded Components	Site /Structures/Improvements	EARG	I	40	0	40	0	No indicators that a life change is required.
C30607	C30607 - Asbestos Abatement	Generating Equipment	EARG	M	30	0	N/A	N/A	Most of the book value is at Burrard, asbestos has been removed from Burrard not encapsulated. Life is being shortened to remaining life of Burrard facility (ending 2020). Book values of asbestos assets to be combined with the building asset by March 31, 2010. The asbestos abatement is a betterment to the building and should be depreciated over the remaining life of the building.
C41002	C41002 - Governor System, Turbine	Generating Equipment	EARG	I	50	0	50 (pre-1991) 25 (post 1990)	0	Old governors lasted 50 years, but new governors are only lasting approximately half the life.
C12005	C12005 - Roads & Trails, Composite Pool	Site /Structures/Improvements	EARG	M	50	0	50	0	No indicators that a life change is required.

Profile ID	Profile ID Descriptions	Catalogue section	BG Response	Asset Type	Average Useful Life (Current)	Salvage % (Current)	Average Useful Life (Revised)	Salvage (Revised)	Depreciation Review Comments
C42102	C42102 - Exciter, Static	Generating Equipment	EARG	I	40	0	40 (pre-1991) 20 (post 1990)	0	Old analog exciters lasted 50 years, but new digital exciters likely have a shorter life (20 years approximately).
C12002	C12002 - Road, Paved / Gravel	Site /Structures/Improvements	EARG	M	50	0	50	0	No indicators that a life change is required.
C25201	C25201 - Pole Structures < 60 kV	Transmission/Distribution	FO	M	50	0	45	0	Poles – two peaks in retirement curve. First peak is at 25 years. Non-cedar poles are deteriorating more rapidly than cedar poles. There are 60 thousand poles greater than 50 years old. About 7 per cent of poles are greater than 50 years old. Recent work by BCH suggests an average useful life less than 50 years. A lot of road widening, requests for city undergrounding leading to earlier retirements Transmission poles are not subject to system expansion, infrastructure projects and motor vehicle accidents. Very few poles are reused. Last 5 to 10 years, shorter and milder winters are allowing greater populations of bugs. Last 2 years system resiliency program for lines at risk of storms. May reduce the number of storm damaged poles. Per Larry Kennedy, the distribution pole lives for other utilities range from 42 to 45 years. Since 2006, performing more inspections. As a result of increased inspections, more poles are being identified as needing to be replaced. The accuracy and completeness of pole management data has improved from last study. Subsequent to previous study, found that there was a backlog of pole removals that was not reflected in the data. Analysis performed by Larry in F09 on actual Pole Mgmt data to end of calendar 2007, suggests a life of 45 years. Based on recent analysis performed by SAM suggesting life of less than 50 years, range of lives for other utilities of 42 – 45 and updated statistical analysis by Larry, agreed that life should be changed to 45 years.
C52201	C52201 - Transformer, Distribution	Transmission/Distribution	FO	M	35	0	35	0	Includes both overhead and underground transformers. All of the underground transformers with PCBs > 50ppm have been removed from service. The PCB issue is not causing early retirements from an accounting perspective. Transformers at risk are all pre-1984. No significant impacts on retirements from Olympic activity. No indication that life change required.

Profile ID	Profile ID Descriptions	Catalogue section	BG Response	Asset Type	Average Useful Life (Current)	Salvage % (Current)	Average Useful Life (Revised)	Salvage (Revised)	Depreciation Review Comments
C55301	C55301 - Cable, Underground < 60 kV	Transmission/Distribution	FO	M	40	0	40	0	Plastic cable is the majority of the cable. Plastic cable is shorter than the life of the lead cable. Early vintage of plastic covered cable have shown some issues. Newer versions of the cable are lasting longer. No indication that life change required.
C25501	C25501 - Ductbanks < 60 kV	Transmission/Distribution	FO	M	50	0	50	0	Rarely ever rebuild ductbanks for Distribution. The ductbanks can accommodate newer cables. No indication that life change required.
C55102	C55102 - Conductor, Overhead < 60 kV	Transmission/Distribution	FO	M	45	0	45	0	Conductors are transferred when poles are replaced. The life of the conductors is longer than the poles. No indication that life change required.
C55201	C55201 - Oh Conductor Services < 60 kV	Transmission/Distribution	FO	M	45	0	45	0	No indication that life change required.
C59401	C59401 - Meters, Billing, Distribution	Transmission/Distribution	FO	M	25	0	25	0	Poorer quality meters had been acquired in the 1990s, shortened the useful life of this vintage of mechanical meters. All new meters are electric meters. When a decision is made to proceed with SMI, a mass retirement of existing meters will be required. When SMI is implemented, should separate all SMI assets as they may be recovered through a separate rate rider. The IT (software) assets and the physical infrastructure should be separate as lives will be different. No indication that life change required.
C55202	C55202 - Ug Conductor Services < 60 kV	Transmission/Distribution	FO	M	45	0	45	0	No indication that life change required.
C81401	C81401 - Trucks >= 1 Ton 4 Wheel Drive	Vehicles/Work Equipment	FO	I	13	25	13	25	2005 implemented reliability centered mtce. Approx 420 assets in Profile ID C81401 There is a large range of vehicles in term of GVW that can be included in this Profile ID. There may be a need to establish a separate Profile ID for larger vehicles in this category in the future. Implementing a new Profile ID will be explored as part of the next depreciation study. Only seeing significant losses on disposal when a vehicle is in an accident or otherwise damaged. Otherwise, the proceeds on disposal are insignificantly different than the NBV of the vehicle. Although there may be differences in lives and salvages of vehicles in this Profile ID; life differences are being offset by salvage percentage differences; therefore, annual depreciation is reasonable for the assets in this Profile ID. No changes to life or salvage required.
C59501	C59501 - Street Lights,Dist. , Owned	Transmission/Distribution	FO	M	40	0	40	0	No indication that life change required.

Profile ID	Profile ID Descriptions	Catalogue section	BG Response	Asset Type	Average Useful Life (Current)	Salvage % (Current)	Average Useful Life (Revised)	Salvage (Revised)	Depreciation Review Comments
C48004	C48004 - Generator, Diesel	Generating Equipment	FO	I	30	0	30	0	Diesel generating units alone are 15 to 25 year lives. When the infrastructure (powerhouse, fuel supply) is included, the life is closer to 25 to 30 years. Due to technological change, there may be a need to decrease the life. No indication that life change required.
	IT Assets >$5M NBV								
C80304	C80304 - Pc Software	Computers	Corp	M	4	0	4	0	Licensing agreement with Microsoft is 4 years. No indication that life change required.
C80504	C80504 - Servers	Computers	Corp	M	5	0	5	0	No indication of a life change for physical servers. Refresh period is still 5 years.
C80305	C80305 - Software Upgrd,Mid-Range Sys	Computers	Corp	I	2	0	2	0	No indication that life change required.
C80508	C80508 - Misc. Network Equipment	Computers	Corp	M	4	0	4	0	Trend to move to virtual storage may impact the life and classification may change to intangibles. No indication of a life change for physical servers.

Depreciation Useful Life Review February/March 2010
Potential Life Change Impacts

PROFILE_ID	PROFILE_DESCR	F11_DEPN_CURRENT_ASLs	F11_DEPN_REVISED_ASLs	F11_DIFFERENCE	Current remaining life	Revised remaining life
C11501	Land, Owned In Fee Simple	-	-	0	1200	1200
C11601	Land Rights, Conversion Only	-	-	0	1200	1200
C11602	Easement / Right-Of-Way	-	-	0	1200	1200
C11604	Land Rights, Other	-	-	0	1200	1200
C11626	Land Rights,Finite Life, 20Yrs	241,954	241,954	0	240	240
C11701	Clearing - Transmission	1,704,016	1,704,016	0	1200	1200
C11801	Recreation Facilities	487,060	487,060	0	240	240
C11901	Surfacing, Yard	944,506	944,506	0	420	420
C12001	Trail, Caterpillar	4,072	4,072	0	600	600
C12002	Road, Paved / Gravel	559,283	559,283	0	600	600
C12005	Roads & Trails, Composite Pool	1,322,840	1,322,840	0	600	600
C12101	Tracks, Railway	2,121	2,121	0	480	480
C12201	Bridge, Wood	210,953	210,953	0	300	300
C12202	Bridge, Steel	346,121	346,121	0	552	552
C12203	Bridge, Concrete	91,224	91,224	0	900	900
C12301	Pad, Helicopter	132,086	132,086	0	300	300
C12401	Drainage System, Yard	333,525	333,525	0	600	600
C12402	Landscaping	34,270	34,270	0	300	300
C12501	Wall, Retaining, Steel	9,907	9,907	0	600	600
C12502	Wall, Retaining, Concrete	107,319	107,319	0	1200	1200
C21001	Dam, Embankment / Concrete	18,979,800	18,979,800	0	1200	1200
C21002	Dam, Crib, Wooden	47,465	47,465	0	420	420
C21101	Dike, Protective	45,149	45,149	0	1200	1200
C21102	Erosion Donut/Bank Protection	258,164	258,164	0	300	300
C21103	Debris/Avalance Deflector	52,058	52,058	0	300	300
C21901	Roofs	643,464	643,464	0	360	360
C22001	Plant, Concrete Or Steel	1,399,041	1,399,041	0	600	600
C22002	Commercial, Concrete Or Steel	4,551,416	4,551,416	0	600	600
C22003	Powerhouse, Integral With Dam	7,940,542	7,940,542	0	1200	1200
C22004	Building, Wood	284,384	284,384	0	180	180
C22005	Building, Composite Pool	6,502,745	6,502,745	0	720	720
C22006	Equipment Shelter	834,954	834,954	0	120	120
C22101	Office Trailer/Mobile Home	406,769	406,769	0	276	276
C22201	Leasehold Improvements	301,558	301,558	0	60	60
C22202	Leasehold Improvements	452,641	452,641	0	120	120
C23001	Spillway, Separate From Dam	2,656,022	2,656,022	0	900	900
C23101	Intake Structure, Power	1,156,626	1,156,626	0	1200	1200
C23201	Penstock, Steel	2,147,151	2,147,151	0	900	900
C23202	Penstock, Concrete	1,297,951	1,297,951	0	1200	1200
C23203	Penstock, Wood	33,293	33,293	0	600	600
C23302	Tank, Surge, Steel	384,559	384,559	0	600	600
C23401	Tailrace	944,662	944,662	0	1200	1200
C23501	Canal	25,397	25,397	0	1200	1200
C23601	Stoplogs, Steel	161,729	161,729	0	720	720
C23602	Stoplogs, Wood	5,671	5,671	0	300	300
C23603	Hoist, Gate	1,368,794	1,368,794	0	660	660

PROFILE_ID	PROFILE_DESCR	F11_DEPN_CURRENT_ASLs	F11_DEPN_REVISED_ASLs	F11_DIFFERENCE	Current remaining life	Revised remaining life
C23604	Gate	2,991,227	2,991,227	0	480	480
C23605	Gates, Embedded Components	719,501	719,501	0	480	480
C23606	Inlet Valves, Penstock & Turbi	63,531	63,531	0	600	600
C23701	Trash Racks	525,355	525,355	0	600	600
C23801	Cranes	1,375,413	1,375,413	0	720	720
C23901	Fishways, Steel	196,628	196,628	0	600	600
C23902	Fishways, Concrete	2,977	2,977	0	1200	1200
C24001	Navigation Locks	415,968	415,968	0	1200	1200
C24002	Controls	107,691	107,691	0	240	240
C24003	Motor	5,000	5,000	0	240	240
C24101	Sluiceway, Separate From Dam	730,080	730,080	0	1200	1200
C24201	Tunnels	946,806	946,806	0	1200	1200
C24301	Slope Stabilization	297,648	297,648	0	1200	1200
C24401	Dock / Wharf	41,872	41,872	0	300	300
C24402	Ramp, Boat/Barge	38,777	38,777	0	240	240
C25101	Structure, Support, Steel	1,811,321	1,811,321	0	780	780
C25102	Structure, Support, Wood	143,099	143,099	0	360	360
C25201	Pole Structures < 60Kv	15,759,956	18,654,090	2,894,133.89	600	540
C25202	Pole Structures > 60Kv	3,418,454	2,638,186	(780,268.01)	600	720
C25203	Tower, Lattice / Asthetic	9,782,971	7,759,205	(2,023,765.78)	780	900
C25301	Foundations	3,154,151	3,154,151	0	480	480
C25401	Ducts & Trenches	618,166	618,166	0	600	600
C25501	Ductbanks < 60Kv	10,426,927	10,426,927	0	600	600
C25502	Ductbanks > 60Kv	660,753	809,729	148,975.71	600	540
C25601	Barriers & Enclosures	138,203	138,203	0	600	600
C25701	Capacitor, <60 Kv	126,642	126,642	0	360	360
C30101	Casing, Boiler	-	-	0	360	360
C30102	Insulation, Boiler	651,118	651,118	0	360	360
C30103	Roof, Boiler	10,350	10,350	0	360	360
C30201	Waterwall, Boiler	-	-	0	360	360
C30203	Superheater, High Temp	-	-	0	360	360
C30204	Superheater, Low Temp	-	-	0	360	360
C30205	Reheater, Boiler	106,782	106,782	0	360	360
C30206	Desuperheater/Attemperator	97,859	97,859	0	120	120
C30301	Header / Drum	173,531	173,531	0	420	420
C30401	Valves, Safety	13,794	13,794	0	360	360
C30501	Piping, High Pressure	162,918	162,918	0	540	540
C30601	Fan, Forced Draft	24,345	24,345	0	480	480
C30602	Breaching / Flue System	263,027	263,027	0	360	360
C30603	Stack, Flue Gases	22,261	22,261	0	360	360
C30604	Preheater, Air	-	-	0	360	360
C30605	Burner, Fuel	345,702	345,702	0	240	240
C30606	Instrumentation, Boiler	171,200	171,200	0	240	240
C30607	Asbestos Abatement	1,591,943	1,591,943	0	360	360
C30608	Control System, Feedwater	-	-	0	240	240
C30609	Seals, Crown	-	-	0	240	240
C30610	Control System, Fuel	-	-	0	240	240
C30611	Desuperheater System	8,510	8,510	0	240	240
C30612	Refractory, Boiler	-	-	0	240	240

PROFILE_ID	PROFILE_DESCR	F11_DEPN_CURRENT_ASLs	F11_DEPN_REVISED_ASLs	F11_DIFFERENCE	Current remaining life	Revised remaining life
C30613	Boiler, Package	81,667	81,667	0	360	360
C30701	Equipment, Water Treatment	626,085	626,085	0	480	480
C30801	Transfer System, Ammonia	36,688	36,688	0	240	240
C30802	Water Deluge System, Ammonia	25,901	25,901	0	240	240
C30803	Vapouriser, Ammonia	37,347	37,347	0	240	240
C30804	Compressor, Vapour, Ammonia	20,196	20,196	0	240	240
C30805	Piping System, Ammonia	31,541	31,541	0	360	360
C30901	Monitoring Equip., Cem	51,092	51,092	0	120	120
C30902	Reporting System, Cem	-	-	0	120	120
C30903	Delivery System,Ammonia,Scr	146,597	146,597	0	240	240
C30904	Catalyst, Scr	110,185	110,185	0	180	180
C31001	Water Intake/Discharge Struct	667,341	667,341	0	600	600
C31002	Protection, Cathodic	38,423	38,423	0	240	240
C31003	Gates, Inlet/Outlet	7,418	7,418	0	360	360
C31004	Screens, Intake	57,447	57,447	0	240	240
C31005	Conduit, Intake/Discharge	4,742	4,742	0	600	600
C31006	Valves	201,138	201,138	0	360	360
C31007	Turbine/Penstock Inlet Valves	99,545	99,545	0	600	600
C33001	Heat Exchanger, Shell & Tube	64,056	64,056	0	360	360
C33002	Pump And Motor	439,272	439,272	0	480	480
C33004	Condenser, Boiler	-	-	0	360	360
C33005	Condenser Air Removal System	1,948	1,948	0	180	180
C34002	Casing, Cylinder	-	-	0	360	360
C34004	Turbine, Composite Pool	74,398	74,398	0	360	360
C34005	Coils, Stator	457,578	457,578	0	240	240
C34006	Rotor, Generator	339,472	339,472	0	360	360
C34007	Generator, Composite Pool	140,230	140,230	0	480	480
C34008	Supervisory System, Turbine	88,403	88,403	0	240	240
C34009	Cooling System, Hydrogen	223,856	223,856	0	480	480
C34013	Generator Oil Coolers	2,040	2,040	0	180	180
C34015	Turbine Blades Sets	55,684	55,684	0	180	180
C41001	Runner / Water Wheel	1,297,978	1,297,978	0	600	600
C41002	Governor System, Turbine	279,674	279,674	0	600	600
C41002B	Governor System, Turbine	474,815	1,323,716	848,901.39	600	300
C41003	Casing, Embedded/Spiral Case	414,027	414,027	0	600	600
C41004	Shaft, Turbine	115,058	115,058	0	600	600
C41005	Gates, Wicket	249,619	249,619	0	600	600
C41006	Cover, Head	290,606	290,606	0	600	600
C41007	Turbine, Hydro, Comp. Pool	5,476,400	5,476,400	0	600	600
C41008	Bearings For Wicket Gate	129,936	129,936	0	300	300
C41501	Draft Tube Water Depression Sy	63,100	63,100	0	300	300
C41601	Unwatering System	236,150	236,150	0	300	300
C41701	Turbine Air Injection Blower	21,211	21,211	0	300	300
C42001	Coils, Stator	3,561,606	3,561,606	0	360	360
C42002	Rotor, Generator	2,581,626	2,581,626	0	600	600
C42003	Generator, Composite Pool	3,990,637	3,990,637	0	600	600
C42101	Exciter, Rotary	562,467	562,467	0	480	480
C42102	Exciter, Static	3,644	3,644	0	480	480
C42102B	Exciter, Static	540,291	1,870,608	1,330,317.06	480	240

PROFILE_ID	PROFILE_DESCR	F11_DEPN_CURRENT_ASLs	F11_DEPN_REVISED_ASLs	F11_DIFFERENCE	Current remaining life	Revised remaining life
C42104	Exciter, Composite Pool	236,041	236,041	0	480	480
C42201	Resistor, Load-Breaking	71,642	71,642	0	300	300
C42501	Piping, Water Cooling System	306,040	306,040	0	480	480
C42502	Monitoring System, Cooling	49,008	49,008	0	240	240
C46501	Cooling System, Water	56,323	56,323	0	180	180
C46502	Engine, Internal Combustion	637,601	637,601	0	300	300
C46701	Heat Exchanger	326,632	326,632	0	360	360
C47001	Intake, Air	46,443	46,443	0	240	240
C47101	Exhaust Structure	274	274	0	300	300
C47201	Turbine, Gas	1,191,514	1,191,514	0	300	300
C47401	Fuel System	84,426	84,426	0	480	480
C48001	Coils, Stator	6,270	6,270	0	480	480
C48002	Rotor, Generator	3,845	3,845	0	480	480
C48003	Generator, Composite Pool	427,508	427,508	0	360	360
C48004	Generator, Diesel	445,571	445,571	0	360	360
C49001	Pump	192,759	192,759	0	240	240
C49002	Motor	34,628	34,628	0	360	360
C49101	Fan & Motor	993	993	0	360	360
C49201	Vacuum System	2,679	2,679	0	300	300
C51001	Condensor,Synchronous,Rotary	19,461	19,461	0	600	600
C51002	Condensor,Synchronous,Static	488,170	488,170	0	480	480
C52101	Transformer,Generator,Stepup	1,399,157	1,399,157	0	480	480
C52102	Transformer, Auto, Bulk Sys	462,147	462,147	0	540	540
C52103	Transformer, Power - > 100Mva	1,848,903	1,311,371	(537,532.27)	480	600
C52104	Transformer, Power - < 100Mva	1,861,715	1,452,125	(409,590.22)	540	660
C52105	Transformer, Station Service	641,409	641,409	0	480	480
C52106	Transformer, Power, Comp Pool	3,697,995	2,274,340	(1,423,655.07)	540	660
C52201	Transformer, Distribution	26,270,193	26,270,193	0	420	420
C52301	Reactor, Oil	1,686,005	831,975	(854,030.26)	300	420
C52302	Reactor, Dry Type	900,303	900,303	0	480	480
C52303	Reactor, Composite Pool	1,324,365	1,324,365	0	480	480
C52401	Oil, 69 Kv & Above	84,361	84,361	0	480	480
C52402	Gas, Sf6, 69 Kv & Above	318,799	318,799	0	480	480
C52403	Oil, < 69 Kv	2,346	2,346	0	420	420
C52404	Transformer,Current,Encaps.	34,756	34,756	0	540	540
C52405	Transformer,Current,Comp. Pool	432,244	432,244	0	600	600
C52406	Comb Ct & Vt Transformer	14,351	14,351	0	480	480
C52501	Transformer,Voltage,Capacitor	331,808	331,808	0	420	420
C52502	Transformer,Voltage,Oil-Fill	79,789	79,789	0	480	480
C52503	Transformer,Voltage,Gas-Fill	27,079	27,079	0	600	600
C52504	Transformer,Voltage,Encaps.	108,727	108,727	0	540	540
C52505	Transformer,Volt,Comp. Pool	259,455	259,455	0	480	480
C52601	Mobile Substations	96,930	96,930	0	300	300
C53101	Capacitor, Shunt	1,656,478	1,656,478	0	360	360
C53201	Capacitor, Series	639,986	639,986	0	420	420
C53202	Metal Oxide Varister (Mov)	174,100	174,100	0	420	420
C53301	Capacitor, Coupling	711,645	711,645	0	420	420
C54101	Breaker,Air/Magnetic	95,644	95,644	0	240	240
C54102	Breaker,Gas(Sf6)12 / 25 Kv	1,303,705	1,303,705	0	360	360

PROFILE_ID	PROFILE_DESCR	F11_DEPN_CURRENT_ASLs	F11_DEPN_REVISED_ASLs	F11_DIFFERENCE	Current remaining life	Revised remaining life
C54103	Breaker,Bulk/Min Oil/Air Blast	296,272	296,272	0	540	540
C54104	Breaker,Gas(Sf6), 69 To 500 Kv	3,284,390	3,284,390	0	540	540
C54105	Breakers, Composite Pool	1,203,914	1,203,914	0	420	420
C54201	Use Individual Disconnect Caus	3,804,854	3,804,854	0	480	480
C54202	Disconnect, 1 Phase, Hookstick	27,755	27,755	0	360	360
C54203	Disconnect, 3 Phase, 12/25Kv	534,413	534,413	0	420	420
C54204	Disconnect, 3 Phase, 69-230Kv	385,609	385,609	0	420	420
C54205	Disconnect, 3 Phase, 500Kv	82,496	82,496	0	420	420
C54401	Switchgear, Metalclad	677,711	677,711	0	360	360
C54501	Circuit Recloser	93,989	93,989	0	480	480
C54601	Circuit Switcher	52,979	52,979	0	360	360
C55101	Conductor, Overhead > 60 Kv	8,540,136	8,540,136	0	720	720
C55102	Conductor, Overhead < 60 Kv	15,196,440	15,196,440	0	540	540
C55103	Line Disconnect Switches	133,257	133,257	0	300	300
C55201	Oh Conductor Services < 60 Kv	5,318,532	5,318,532	0	540	540
C55202	Ug Conductor Services < 60 Kv	504,199	504,199	0	540	540
C55301	Cable, Underground < 60 Kv	15,552,718	15,552,718	0	480	480
C55302	Cable,Underground >60Kv	2,476,489	1,939,954	(536,535.69)	480	540
C55303	Cable,Submarine > 60 Kv	14,346,453	14,346,453	0	540	540
C55304	Cable, Submarine < 60 Kv	127,398	127,398	0	420	420
C55401	Buswork & Station Conductor	2,397,397	2,397,397	0	720	720
C55501	Grounding Systems	957,546	957,546	0	480	480
C56001	Insulators	1,294,625	1,294,625	0	660	660
C57001	Arrestor, Surge	1,164,755	1,164,755	0	360	360
C58001	Converter	5,140	5,140	0	360	360
C58002	Inverter	20,879	20,879	0	360	360
C58101	Var Compensator, Static	421,005	421,005	0	480	480
C58201	Resistor, Anode Damping	19,981	19,981	0	300	300
C58901	Power Supply, Solar Panel	16,934	16,934	0	120	120
C59001	Power Supply, Uninterruptible	887,420	887,420	0	180	180
C59101	Regulator, Feeder Circuit	198,164	198,164	0	360	360
C59201	Charger System, Battery	619,088	619,088	0	240	240
C59301	Storage Batteries, Bank	419,439	419,439	0	240	240
C59401	Meters, Billing, Distribution	8,652,706	8,652,706	0	300	300
C59402	Meters, Transmission	13,758	13,758	0	360	360
C59501	Street Lights,Dist. , Owned	915,368	915,368	0	480	480
C59502	Street Lights,Dist. , Leased	27,747	27,747	0	480	480
C59601	Metering, Dcp, Trolleys	106,070	106,070	0	420	420
C61001	Fencing	808,678	808,678	0	300	300
C61101	Alarm/Security System	633,213	633,213	0	240	240
C61201	Booms, Floating	157,097	157,097	0	180	180
C61202	Booms, Floating Cedar	119,693	119,693	0	300	300
C61203	Booms, Oil Containmnet	9,819	9,819	0	180	180
C62001	Fire Protection System	1,445,548	1,445,548	0	300	300
C62501	Firefighting Equipment	25,712	25,712	0	300	300
C63001	Exercise Equipment	21,788	21,788	0	60	60
C65001	Panels/Cubicles, P & C	13,869,703	13,869,703	0	240	240
C65101	Fault Locating& Reporting	100,126	100,126	0	240	240
C67001	Liner, Pvc, Spill Containment	26,370	26,370	0	420	420

PROFILE_ID	PROFILE_DESCR	F11_DEPN_CURRENT_ASLs	F11_DEPN_REVISED_ASLs	F11_DIFFERENCE	Current remaining life	Revised remaining life
C67003	Containment Facility, Concrete	271,093	271,093	0	600	600
C67004	Spill Pond, Natural	6,711	6,711	0	300	300
C67005	Oil Spill Containment	308,476	308,476	0	420	420
C67006	Containment System, Oil Spill	403,384	403,384	0	420	420
C68001	Carrier System, Power Line	773,449	773,449	0	180	180
C68101	Antennae & Waveguide,Microwave	545,207	545,207	0	240	240
C68201	Control Centre (Master Equip)	226,234	226,234	0	144	144
C68202	Terminal Unit,Remote (Slave)	931,883	931,883	0	240	240
C68203	Integrated Control/Data(Icda)	44,166	44,166	0	60	60
C68204	Distributed Control System	893,185	893,185	0	240	240
C68205	Global Positioning Equipment	16,412	16,412	0	120	120
C68301	Radio,Microwave,Analog	56,463	56,463	0	420	420
C68302	Radio,Microwave,Digital	825,777	1,257,279	431,501.81	420	300
C68303	Microwave, Conversion Only	66,942	66,942	0	240	240
C68401	Multiplex Device, Analog	-	-	0	60	60
C68402	Multiplex Device, Digital	776,205	776,205	0	240	240
C68501	Radio Systems, Uhf/Vhff	132,984	132,984	0	420	420
C68502	Mobile Dispatch System	303,929	303,929	0	60	60
C68503	Radio Equipment, Protection	1,332	1,332	0	300	300
C68601	Protection Tone System	589,646	589,646	0	240	240
C68602	Digital Teleprotection System	156,429	156,429	0	240	240
C68701	Wave Trap / Line Trap	54,603	54,603	0	240	240
C68801	Fibre Optic System	794,772	794,772	0	240	240
C68901	Telephone Equipment, Pbx/Pax	404,495	404,495	0	240	240
C68902	Telephone Systems, Conv. Only	-	-	0	120	120
C68903	Tel Equip, Monitoring System	91,426	91,426	0	60	60
C68904	Telephone System, Cellular	15,968	15,968	0	60	60
C70001	Cable, Entrance Protection	211,632	211,632	0	240	240
C70101	Hydrometeorological Equipment	181,052	181,052	0	180	180
C70102	Accelerometers	21,300	21,300	0	240	240
C70103	Seismic Monitoring Equipment	123,599	123,599	0	240	240
C73001	Cooling System, Air	185,942	185,942	0	300	300
C74001	Motor-Generator Sets	138,345	138,345	0	420	420
C75101	Drier, Air	89,796	89,796	0	300	300
C75102	Piping/Valving, Steel	22,098	22,098	0	240	240
C75103	Piping, Stainless Steel	53,339	53,339	0	480	480
C75104	Compressor, Air	275,915	275,915	0	300	300
C75201	Tanks, Steel, Air/Fuel	305,700	305,700	0	360	360
C75202	Tank,Fibrglas,Dbl Bottom,Fuel	35,230	35,230	0	360	360
C75203	Tank,Air-Stainless/Oil-Steel	124,687	124,687	0	360	360
C75204	Tanks, Concrete	93,804	93,804	0	360	360
C75205	Tanks, Wood	12,349	12,349	0	300	300
C75301	Water Supply System	349,758	349,758	0	480	480
C80101	Computer,Hardware,Micro (Pc)	898,645	898,645	0	48	48
C80102	Computer,Hardware,Mini	20,570	20,570	0	60	60
C80103	Computer,Hardware,Input/Output	484,026	484,026	0	60	60
C80104	Computer,H/Ware,Comp. Pool,Pcs	7,641	7,641	0	60	60
C80105	Laptops	619,803	619,803	0	36	36
C80201	Computer,Mainframe, Cpu	11,584	11,584	0	60	60

PROFILE_ID	PROFILE_DESCR	F11_DEPN_CURRENT_ASLs	F11_DEPN_REVISED_ASLs	F11_DIFFERENCE	Current remaining life	Revised remaining life
C80202	Computer Memory, Mainframe	135,761	135,761	0	60	60
C80203	SAN, Controllers, Disks/Tapes	56,144	56,144	0	60	60
C80204	Storage Device, Disc/Tape	424,294	424,294	0	60	60
C80205	Workstation, Dumb Terminal	-	-	0	180	180
C80208	Printer,Mainframe,Laser	15,089	15,089	0	120	120
C80209	Plotter,Mainframe,Colour	7,723	7,723	0	120	120
C80211	Controller, Telecom, Master	191	191	0	240	240
C80213	Burster/Post-Process Device	10,087	10,087	0	120	120
C80214	Terminal,Meter Reading,Handhld	28,047	28,047	0	60	60
C80302	Software, Mainframe	13,173,356	13,173,356	0	120	120
C80303	Software, Mid-Range Systems	8,970,575	8,970,575	0	60	60
C80304	Pc Software	868,708	868,708	0	48	48
C80305	Software Upgrd,Mid-Range Sys	2,204,347	2,204,347	0	24	24
C80306	Network Software	630,037	630,037	0	60	60
C80307	Network Software Upgrades	100,277	100,277	0	24	24
C80401	Stimulator, Training	40,182	40,182	0	60	60
C80501	Premise Cabling	55,328	55,328	0	84	84
C80502	Routers	35,154	35,154	0	60	60
C80503	Switches	223,249	223,249	0	60	60
C80504	Servers	2,484,506	2,484,506	0	60	60
C80505	Servers	545,122	545,122	0	60	60
C80508	Misc. Network Equipment	2,592,793	2,592,793	0	48	48
C81001	Automobiles	236,442	236,442	0	96	96
C81101	Trucks < 1 Ton 2 Wheel Drive	437,234	437,234	0	96	96
C81201	Trucks < 1 Ton 4 Wheel Drive	1,699,182	1,699,182	0	96	96
C81301	Trucks >= 1 Ton 2 Wheel Drive	966,905	966,905	0	156	156
C81302	Truck >= 1 Ton 2 Wheel Drive	52,056	52,056	0	156	156
C81401	Trucks >= 1 Ton 4 Wheel Drive	1,341,940	1,341,940	0	156	156
C81501	Trucks >= 1 Ton 6 Wheel Drive	139,057	139,057	0	144	144
C81601	Tractor, Highway	42,825	42,825	0	108	108
C81701	Aerial Device	801,681	801,681	0	156	156
C81702	Line / Service / Van Body	481,318	481,318	0	180	180
C81703	Derricks / Diggers	347,958	347,958	0	180	180
C81704	Ride-A-Rails	(1,141)	(1,141)	0	300	300
C81799	Misc Access, Conversion Only	(4,468)	(4,468)	0	120	120
C82501	Forklift / Pallet Jack	131,508	131,508	0	240	240
C82502	Snow Vehicle	(30,484)	(30,484)	0	240	240
C82503	Sweeper	8,066	8,066	0	180	180
C82504	Loader / Backhoe	6,382	6,382	0	204	204
C82505	Trailer, Reel/Pole/Utility	140,252	140,252	0	240	240
C82506	Welder, Mobile, Self-Powered	-	-	0	180	180
C82507	Compressor,Mobile,Self-Powered	4,310	4,310	0	180	180
C82508	Chipper	-	-	0	180	180
C82509	Tractor	21,810	21,810	0	120	120
C82510	Railcars	9,764	9,764	0	420	420
C82512	Regen Plan, Xformer Oil	10,466	10,466	0	180	180
C82513	Manlift	66,661	66,661	0	180	180
C82514	All Terrain Vehicle	10,081	10,081	0	96	96
C82550	Tools/Work Equipment, Misc	2,329,616	2,329,616	0	180	180

PROFILE_ID	PROFILE_DESCR	F11_DEPN_CURRENT_ASLs	F11_DEPN_REVISED_ASLs	F11_DIFFERENCE	Current remaining life	Revised remaining life
C82551	Tools/Work Equipment, Misc	1,271,759	1,271,759	0	180	180
C82601	Test/Calibration Equipment	349,084	349,084	0	180	180
C82603	Manufacturing/Test Equipment	156,805	156,805	0	180	180
C82604	Equipment, Line Construction	31,813	31,813	0	60	60
C83001	Boat	49,796	49,796	0	180	180
C83002	Boat, Tugboat	9,084	9,084	0	240	240
C85001	Office Furniture	1,195,759	1,195,759	0	180	180
C85002	Office Equipment	62,633	62,633	0	180	180
C85003	Signs/Plaques	24,800	24,800	0	360	360
C85004	Carpet	69,853	69,853	0	180	180
C87001	Pcb Solids Destruction Plant	13,394	13,394	0	60	60
C88001	Lab Equipment, Hi-Pwr Lab	47,330	47,330	0	240	240
C88002	Lab Equipment, Misc	11,284	11,284	0	180	180
C88003	Lab Equipment, Hi-Pwr Lab	14,271	14,271	0	180	180
C89001	Intangible/Franchise/Consent	474,855	474,855	0	120	120
C89501	Animal Preventative Equipment	303,914	303,914	0	240	240
C90003	Asset Retirement Cost Assets	163,250	163,250	0	120	120
C90004	Water User Plans	2,836,585	2,836,585	0	120	120
	Total	**362,957,491.07**	**362,045,943.63**	**(911,547.44)**		

Note: C41002B and **C42102B** are assets within each of these profile IDs that were acquired after 1990.
These "B" profile IDs were created for them because assets acquired 1990 should be depreciated over half the original effective life

41.0 Depreciation

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR No. 1.23.1, pdf p. 288; BC Hydro Response to AMPC IR No. 1.23.7, pdf p. 313; BC Hydro Response to AMPC IR No. 1.23.7.1, pdf p. 314

On pdf p. 288, BC Hydro states as follows:

BC Hydro currently has no indication that asset life expectations have changed in a significant way that would have a material impact on depreciation expense. Therefore, we believe that the cost and effort of performing the study would outweigh the benefits.

AMPC seeks to understand BC Hydro's response.

2.41.3 Please provide all management notes, asset condition assessments and working papers produced since the last approved depreciation study that provide justification for continuing to apply the estimated life expectancies determined by that last depreciation study, on the basis of current life characteristics.

RESPONSE:

BC Hydro complies with International Accounting Standard 16 which outlines the requirements for annual reviews of residual values and useful lives as discussed in BC Hydro's response to AMPC IR 2.41.9.

BC Hydro considers factors that could materially impact depreciation expense when reviewing the useful lives of asset classes. For example, the useful lives of analog meters were reduced as approved by BCUC Order No. G-115-11 because the useful lives were shortened as a result of the meters being replaced prior to end of life as a result of the Smart Metering Initiative. In addition, as identified in section 8.2.1 of Chapter 8 of the Application, the useful lives of Burrard assets were reduced due to changes in the expected useful life of the facility.

In BC Hydro's response to AMPC IR 2.41.2, BC Hydro provides documentation regarding a depreciation review conducted in fiscal 2010. In addition, the Gannett Fleming Report on IFRS Componentization was submitted as Appendix G to the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application.

41.0 Depreciation

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR No. 1.23.1, pdf p. 288; BC Hydro Response to AMPC IR No. 1.23.7, pdf p. 313; BC Hydro Response to AMPC IR No. 1.23.7.1, pdf p. 314

On pdf p. 288, BC Hydro states as follows:

BC Hydro currently has no indication that asset life expectations have changed in a significant way that would have a material impact on depreciation expense. Therefore, we believe that the cost and effort of performing the study would outweigh the benefits.

AMPC seeks to understand BC Hydro's response.

2.41.4 Please confirm that BC Hydro has an obligation to periodically test the assumptions that feed into the assessment of its material expenses, to avoid a material misstatement. If confirmed, please identify what BC Hydro understands this obligation to consist of. If not confirmed, please fully explain your answer.

RESPONSE:

BC Hydro must ensure that the financial statements are free from material misstatement as evidenced by the following statement in the auditor's opinion on BC Hydro's fiscal 2019 financial statements:

> **"Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error".**

In order to ensure that the financial statements are free from material misstatement, BC Hydro must review assumptions that feed into the assessment of its material expenses to ensure that they continue to be reasonable. The requirement to review assumptions in respect of Property, Plant and Equipment is per International Accounting Standard 16 paragraph 51 guidance:

> **"The residual value and the useful life of an asset shall be reviewed at least at each financial year-end and, if expectations differ from previous estimates, the change(s)**

shall be accounted for as a change in an accounting estimate in accordance with IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors".

There is no requirement that the assumptions be tested periodically.

41.0 Depreciation

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR No. 1.23.1, pdf p. 288; BC Hydro Response to AMPC IR No. 1.23.7, pdf p. 313; BC Hydro Response to AMPC IR No. 1.23.7.1, pdf p. 314

On pdf p. 288, BC Hydro states as follows:

BC Hydro currently has no indication that asset life expectations have changed in a significant way that would have a material impact on depreciation expense. Therefore, we believe that the cost and effort of performing the study would outweigh the benefits.

AMPC seeks to understand BC Hydro’s response.

2.41.5 Please identify all material asset retirements, if any, that occurred prior to the service life estimate for the particular asset(s), as set out in the last depreciation study. For each such retirement, please fully explain:

(a) Why the retirement occurred;
(b) How far in advance of the applicable estimated service life the asset was retired; and
(c) Why, in BC Hydro's view, the retirement did not amount to an indication that the estimated life for that asset class had changed.

RESPONSE:

For purposes of BC Hydro’s response to this request, the materiality threshold used was assets with an original cost of $10 million or higher, which had asset retirements from fiscal 2017 to fiscal 2019. BC Hydro reviewed asset retirements for the fiscal 2017 to fiscal 2019 period and did not identify any individual specific asset with a cost of $10 million or higher which was fully retired prior to the end of the expected useful life of the asset.

This review excluded mass asset retirements, as they are recorded on a pooled basis and individual assets within the pools are not material.

41.0 Depreciation

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR No. 1.23.1, pdf p. 288; BC Hydro Response to AMPC IR No. 1.23.7, pdf p. 313; BC Hydro Response to AMPC IR No. 1.23.7.1, pdf p. 314

On pdf p. 288, BC Hydro states as follows:

BC Hydro currently has no indication that asset life expectations have changed in a significant way that would have a material impact on depreciation expense. Therefore, we believe that the cost and effort of performing the study would outweigh the benefits.

AMPC seeks to understand BC Hydro’s response.

2.41.6 Please identify any material assets that exceeded their estimated service life for the particular assets, as set out in the last depreciation study. For each such retirement, please fully explain:

(a) Why the asset, in BC Hydro's view, has exceeded its estimated service life;
(b) How far past the applicable estimated service life the asset remained in service (also noting if the asset is still in service); and
(c) Why, in BC Hydro's view, the retirement did not amount to an indication that the estimated life for that asset class had changed.

RESPONSE:

For purposes of BC Hydro’s response to this request, the materiality threshold used was assets with an original cost of $10 million or higher, which had a net book value of zero at March 31, 2019, representing assets that were fully depreciated and had not been retired. BC Hydro reviewed the assets meeting the threshold and did not identify any individual specific assets that were still in use.

41.0 Depreciation

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR No. 1.23.1, pdf p. 288; BC Hydro Response to AMPC IR No. 1.23.7, pdf p. 313; BC Hydro Response to AMPC IR No. 1.23.7.1, pdf p. 314

Reference (iii): Exhibit B-6, BC Hydro Response to AMPC IR No. 1.23.8 and 1.23.8.1, pdf pp. 315-316

At pdf pp. 315-316, BC Hydro states that its applied for depreciation rate for the Burrard synchronous condense facility is as such to ensure that the assets are depreciated by no later than the end of fiscal 2025. BC Hydro states that "this date was selected based on a conservative estimate of the remaining useful life of the generators, which are the most significant component of the remaining assets at the facility." At pdf p. 319, BC Hydro acknowledges that “the depreciation rates [of these assets] are based on fully depreciating all asset classes by no later than fiscal 2025 and not on the assets’ useful life”.

AMPC wishes to better understand the basis for BC Hydro’s depreciation rate for the Burrard synchronous condense asset.

2.41.7 Please explain why it is appropriate to (i) depreciate <u>all</u> of the Burrard synchronous condense facility assets to coincide with the remaining useful life of the generators, and (ii) use a <u>conservative</u> estimate of the remaining useful life of the generators.

RESPONSE:

BC Hydro currently plans to replace the existing Burrard synchronous condenser capacity at the end of fiscal 2025. As BC Hydro plans to replace the existing capacity at Burrard, the economic benefits of the existing Burrard assets will cease in fiscal 2025.

IAS 16 paragraph 57 provides the following guidance regarding the useful life of an asset.

> **57 The useful life of an asset is defined in terms of the asset's expected utility to the entity. The asset management policy of the entity may involve the disposal of assets after a specified time or after consumption of a specified proportion of the future economic benefits embodied in the asset. Therefore, the useful life of an asset may be shorter than its economic life. The estimation of the useful life of the asset is**

a matter of judgement based on the experience of the entity with similar assets.

Paragraph 57 identifies that the useful life of an asset is its expected utility to the entity and that the useful life of an asset may be shorter than its economic life. The expected utility to BC Hydro of the Burrard assets will cease in fiscal 2025. Although some of the generators may physically be able to generate beyond fiscal 2025, they are not expected to be used beyond fiscal 2025. Therefore, it is appropriate to depreciate all of the Burrard assets over the period ending in fiscal 2025, which coincides with a conservative estimate of the remaining useful lives of the generators.

41.0 Depreciation

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR No. 1.23.1, pdf p. 288; BC Hydro Response to AMPC IR No. 1.23.7, pdf p. 313; BC Hydro Response to AMPC IR No. 1.23.7.1, pdf p. 314

Reference (iii): Exhibit B-6, BC Hydro Response to AMPC IR No. 1.23.8 and 1.23.8.1, pdf pp. 315-316

At pdf pp. 315-316, BC Hydro states that its applied for depreciation rate for the Burrard synchronous condense facility is as such to ensure that the assets are depreciated by no later than the end of fiscal 2025. BC Hydro states that "this date was selected based on a conservative estimate of the remaining useful life of the generators, which are the most significant component of the remaining assets at the facility." At pdf p. 319, BC Hydro acknowledges that “the depreciation rates [of these assets] are based on fully depreciating all asset classes by no later than fiscal 2025 and not on the assets’ useful life”.

AMPC wishes to better understand the basis for BC Hydro’s depreciation rate for the Burrard synchronous condense asset.

2.41.8 Please provide a non-conservative (i.e., best) estimate for the remaining useful life of the synchronous condense facility.

RESPONSE:

Please refer to pages 84 to 85 of Attachment 1 of Appendix J of the Application and to page 58 of Attachment 1 of Appendix K of the Application, where BC Hydro states that the Burrard Synchronous Condenser units are at, or near, the end of their useful life.

Recent performance of the four Burrard Synchronous Condenser units has been declining with a number of significant forced outages including:

- **Unit 2 Synchronous Condenser has been forced out of service since 2016.**
- **Unit 3 Synchronous Condenser is of similar vintage to Unit 2, and a similar forced outage to that experienced on Unit 2 is becoming increasingly likely. Stator and rotor re-winding is required to avoid a similar outage.**

As discussed in BC Hydro’s response to AMPC IR 2.41.7, BC Hydro currently plans to replace the existing Burrard synchronous condenser capacity at the end of fiscal 2025 and therefore any economic benefits of the existing Burrard assets will cease at that time.

41.0 Depreciation

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR No. 1.23.1, pdf p. 288; BC Hydro Response to AMPC IR No. 1.23.7, pdf p. 313; BC Hydro Response to AMPC IR No. 1.23.7.1, pdf p. 314

Reference (iv): International Accounting Standards, IAS 16 (attached as Appendix B)

IAS 16.51 states as follows:

> 51. The residual value and the useful life of an asset shall be reviewed at least at each financial year‐end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors.

AMPC would like to understand how BC Hydro understands and has followed IAS 16.

2.41.9 Please confirm that IAS 16 specifies that the residual value and the useful life of an asset should be reviewed at least each financial year-end.

RESPONSE:

Confirmed. International Accounting Standard 16 (IAS 16) paragraph 51 specifies that the residual value and the useful life of an asset should be reviewed at least each financial year-end. IAS 16 states the following:

> **51 The residual value and the useful life of an asset shall be reviewed at least at each financial year-end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors.**

BC Hydro complies with IAS 16 paragraph 51 by considering whether there have been any changes in the factors that affect the useful lives of asset classes that are expected to have a material impact on BC Hydro’s depreciation expense. Management annually considers whether there are any impaired assets, assets that are no longer being used or significant write-offs of assets in-service that have been recorded.

When BC Hydro identifies that assets will be removed from service prior to the end of their expected useful lives and they have a material book value, the remaining useful life of the asset is reduced to reflect the change in expected life.

41.0 Depreciation

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR No. 1.23.1, pdf p. 288; BC Hydro Response to AMPC IR No. 1.23.7, pdf p. 313; BC Hydro Response to AMPC IR No. 1.23.7.1, pdf p. 314

Reference (iv): International Accounting Standards, IAS 16 (attached as Appendix B)

IAS 16.51 states as follows:

> 51. The residual value and the useful life of an asset shall be reviewed at least at each financial year‑end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors.

AMPC would like to understand how BC Hydro understands and has followed IAS 16.

2.41.10 Please confirm that BC Hydro has not reviewed the residual value and the useful life of its assets each financial year-end (or more frequently) as required by IAS 16. If not confirmed, please fully explain.

RESPONSE:

Not confirmed. Please refer to BC Hydro's response to AMPC IR 2.41.9, where we explain that BC Hydro complies with International Accounting Standard 16 by considering whether there have been any changes in the factors that affect the useful lives of asset classes that are expected to have a material impact on BC Hydro's depreciation expense and considering whether there are any impaired assets, assets that are no longer being used or significant write-offs of assets in-service that have been recorded.

42.0 Fiscal 2007 to Fiscal 2008 Revenue Requirements Application Depreciation Study

Reference (i): F07/F08 Revenue Requirements Application Depreciation Studies Appendix F, as referred to in BC Hydro Response to AMPC IR 1.23.4, pp. 25 – 27 and Tables 1 and 2 at pp. 31 – 38.

At pp. 25 – 27 of the F07/F08 Revenue Requirements Application Depreciation Studies, BC Hydro described two methodologies it used to determine the average service lives for various asset classes as follows:

> Survivor Curve Judgments. The survivor curve estimates were based on judgment which considered a number of factors. The primary factors were the statistical analysis of data; current policies and outlook as determined during conversations with management personnel; and average service life estimates of this Company and other electric companies.
>
> In the circumstances of number of Profile ID's, BC Hydro provided a detailed database that included the aged surviving balances as at March 31, 2003, representing the plant providing utility service sorted by the year in which it was installed. The annual aged retirements were determined using one of three methods as follows:
>
> - The aged retirement information was available for a number of transaction years from the companies' current accounting and operational systems;
> - The annual unaged retirement transactions were available from the companies' current accounting and operational systems. The annual retirement transactions were then aged using the computed mortality method as previously described; or
> - The annual retirements of plant physically removed were determined on a unit basis from various operational systems within the company. The physical retirements (on a number of units basis) were costed using standardized costs which were aged using the computed mortality method as previously described.
>
> This information provided at least a 10 year experience band that was analyzed using the retirement rate method of survivor curve estimation. Additionally, in a number of circumstances experience bands representing many decades were available. In circumstances where multiple Profile ID's represented similar assets and the combination of the multiple Profile ID's would still result in a group of homogenous assets, the retirement rate analysis was made over the combined group. The average service lives determined from use of the retirement rate method of analysis are summarized on Table 1 at pages III-4 through III-6 of this report.

In the circumstances of the remaining Profile ID's the retirement rate method could not be used in the development of the average service lives. In these circumstances the average service lives were developed on judgment of Gannett Fleming that considered the current policies and outlook as determined during conversations with management personnel; and average service life estimates of previous studies of this Company and other electric companies. A number of these Profile ID's represented accounts that contained the least amount of investment in the system. 109 Profile ID's comprised over 95% of the BC Hydro investment (Primary Profile ID's). Approximately 250 Profile ID's comprise the investment of the remaining 5% of company investment. In a limited number of cases, the use of judgment served as the primary basis for the survivor curve estimate for the primary Profile ID's as sufficient information did not exist for use of the retirement rate method of average service life analysis. The average service lives determined based on the judgment of Gannett Fleming is summarized on Table 2 at pages III-8 through III-9 of this report.

AMPC wants to better understand the methodologies used to develop the last full depreciation study, to better assess its accuracy.

2.42.1 Please confirm that, where possible, BC Hydro used the retirement rate method to estimate asset average service lives for the F07/F08 Revenue Requirements Application Depreciation Studies.

RESPONSE:

Confirmed.

42.0 Fiscal 2007 to Fiscal 2008 Revenue Requirements Application Depreciation Study

Reference (i): F07/F08 Revenue Requirements Application Depreciation Studies Appendix F, as referred to in BC Hydro Response to AMPC IR 1.23.4, pp. 25 – 27 and Tables 1 and 2 at pp. 31 – 38.

At pp. 25 – 27 of the F07/F08 Revenue Requirements Application Depreciation Studies, BC Hydro described two methodologies it used to determine the average service lives for various asset classes as follows:

> Survivor Curve Judgments. The survivor curve estimates were based on judgment which considered a number of factors. The primary factors were the statistical analysis of data; current policies and outlook as determined during conversations with management personnel; and average service life estimates of this Company and other electric companies.
>
> In the circumstances of number of Profile ID's, BC Hydro provided a detailed database that included the aged surviving balances as at March 31, 2003, representing the plant providing utility service sorted by the year in which it was installed. The annual aged retirements were determined using one of three methods as follows:
>
> - The aged retirement information was available for a number of transaction years from the companies' current accounting and operational systems;
> - The annual unaged retirement transactions were available from the companies' current accounting and operational systems. The annual retirement transactions were then aged using the computed mortality method as previously described; or
> - The annual retirements of plant physically removed were determined on a unit basis from various operational systems within the company. The physical retirements (on a number of units basis) were costed using standardized costs which were aged using the computed mortality method as previously described.
>
> This information provided at least a 10 year experience band that was analyzed using the retirement rate method of survivor curve estimation. Additionally, in a number of circumstances experience bands representing many decades were available. In circumstances where multiple Profile ID's represented similar assets and the combination of the multiple Profile ID's would still result in a group of homogenous assets, the retirement rate analysis was made over the combined group. The average service lives determined from use of the retirement rate method of analysis are summarized on Table 1 at pages III-4 through III-6 of this report.

In the circumstances of the remaining Profile ID's the retirement rate method could not be used in the development of the average service lives. In these circumstances the average service lives were developed on judgment of Gannett Fleming that considered the current policies and outlook as determined during conversations with management personnel; and average service life estimates of previous studies of this Company and other electric companies. A number of these Profile ID's represented accounts that contained the least amount of investment in the system. 109 Profile ID's comprised over 95% of the BC Hydro investment (Primary Profile ID's). Approximately 250 Profile ID's comprise the investment of the remaining 5% of company investment. In a limited number of cases, the use of judgment served as the primary basis for the survivor curve estimate for the primary Profile ID's as sufficient information did not exist for use of the retirement rate method of average service life analysis. The average service lives determined based on the judgment of Gannett Fleming is summarized on Table 2 at pages III-8 through III-9 of this report.

AMPC wants to better understand the methodologies used to develop the last full depreciation study, to better assess its accuracy.

2.42.2 Please confirm that, given the passage of time since the F07/F08 Revenue Requirements Application Depreciation Studies, it would now be possible to assess the asset classes that could not be assessed using the retirement rate method in the creation of the F07/F08 Revenue Requirements Application Depreciation Studies (and were estimated by the professional judgment of Gannet Fleming instead).

RESPONSE:

Not confirmed. The passage of time alone would not make it possible to assess the asset classes using the retirement rate method for those classes that were assessed using professional judgement by Gannett Fleming. Many of the constraints identified in the previous study for using the retirement rate method continue to exist.

The useful life was not assessed using the retirement rate method for many of the Profile IDs (Asset Classes). BC Hydro records many assets in the financial system on a pooled basis and does not track the number of asset units in the financial system.

In many cases, there may be a record of the number of units in-service in operational systems but there is no information available on the components (i.e., additions and retirements) or changes in the number of outstanding units. Also, there may be limited or no data on the year the assets were installed (i.e., vintage data).

42.0 Fiscal 2007 to Fiscal 2008 Revenue Requirements Application Depreciation Study

Reference (i): F07/F08 Revenue Requirements Application Depreciation Studies Appendix F, as referred to in BC Hydro Response to AMPC IR 1.23.4, pp. 25 – 27 and Tables 1 and 2 at pp. 31 – 38.

At pp. 25 – 27 of the F07/F08 Revenue Requirements Application Depreciation Studies, BC Hydro described two methodologies it used to determine the average service lives for various asset classes as follows:

> Survivor Curve Judgments. The survivor curve estimates were based on judgment which considered a number of factors. The primary factors were the statistical analysis of data; current policies and outlook as determined during conversations with management personnel; and average service life estimates of this Company and other electric companies.
>
> In the circumstances of number of Profile ID's, BC Hydro provided a detailed database that included the aged surviving balances as at March 31, 2003, representing the plant providing utility service sorted by the year in which it was installed. The annual aged retirements were determined using one of three methods as follows:
>
> - The aged retirement information was available for a number of transaction years from the companies' current accounting and operational systems;
> - The annual unaged retirement transactions were available from the companies' current accounting and operational systems. The annual retirement transactions were then aged using the computed mortality method as previously described; or
> - The annual retirements of plant physically removed were determined on a unit basis from various operational systems within the company. The physical retirements (on a number of units basis) were costed using standardized costs which were aged using the computed mortality method as previously described.
>
> This information provided at least a 10 year experience band that was analyzed using the retirement rate method of survivor curve estimation. Additionally, in a number of circumstances experience bands representing many decades were available. In circumstances where multiple Profile ID's represented similar assets and the combination of the multiple Profile ID's would still result in a group of homogenous assets, the retirement rate analysis was made over the combined group. The average service lives determined from use of the retirement rate method of analysis are summarized on Table 1 at pages III-4 through III-6 of this report.

> In the circumstances of the remaining Profile ID's the retirement rate method could not be used in the development of the average service lives. In these circumstances the average service lives were developed on judgment of Gannett Fleming that considered the current policies and outlook as determined during conversations with management personnel; and average service life estimates of previous studies of this Company and other electric companies. A number of these Profile ID's represented accounts that contained the least amount of investment in the system. 109 Profile ID's comprised over 95% of the BC Hydro investment (Primary Profile ID's). Approximately 250 Profile ID's comprise the investment of the remaining 5% of company investment. In a limited number of cases, the use of judgment served as the primary basis for the survivor curve estimate for the primary Profile ID's as sufficient information did not exist for use of the retirement rate method of average service life analysis. The average service lives determined based on the judgment of Gannett Fleming is summarized on Table 2 at pages III-8 through III-9 of this report.

AMPC wants to better understand the methodologies used to develop the last full depreciation study, to better assess its accuracy.

2.42.3 Please confirm that the retirement rate method was preferred in the F07/F08 Revenue Requirements Application Depreciation Studies over the professional judgment method because it was considered more accurate. If not confirmed, please fully explain your answer.

RESPONSE:

Confirmed. The retirement rate method was preferred. The method was used by BC Hydro in the study where possible and the lives determined in the study continue to be used.

42.0 Fiscal 2007 to Fiscal 2008 Revenue Requirements Application Depreciation Study

Reference (i): F07/F08 Revenue Requirements Application Depreciation Studies Appendix F, as referred to in BC Hydro Response to AMPC IR 1.23.4, pp. 25 – 27 and Tables 1 and 2 at pp. 31 – 38.

At pp. 25 – 27 of the F07/F08 Revenue Requirements Application Depreciation Studies, BC Hydro described two methodologies it used to determine the average service lives for various asset classes as follows:

> Survivor Curve Judgments. The survivor curve estimates were based on judgment which considered a number of factors. The primary factors were the statistical analysis of data; current policies and outlook as determined during conversations with management personnel; and average service life estimates of this Company and other electric companies.
>
> In the circumstances of number of Profile ID's, BC Hydro provided a detailed database that included the aged surviving balances as at March 31, 2003, representing the plant providing utility service sorted by the year in which it was installed. The annual aged retirements were determined using one of three methods as follows:
>
> - The aged retirement information was available for a number of transaction years from the companies' current accounting and operational systems;
> - The annual unaged retirement transactions were available from the companies' current accounting and operational systems. The annual retirement transactions were then aged using the computed mortality method as previously described; or
> - The annual retirements of plant physically removed were determined on a unit basis from various operational systems within the company. The physical retirements (on a number of units basis) were costed using standardized costs which were aged using the computed mortality method as previously described.
>
> This information provided at least a 10 year experience band that was analyzed using the retirement rate method of survivor curve estimation. Additionally, in a number of circumstances experience bands representing many decades were available. In circumstances where multiple Profile ID's represented similar assets and the combination of the multiple Profile ID's would still result in a group of homogenous assets, the retirement rate analysis was made over the combined group. The average service lives determined from use of the retirement rate method of analysis are summarized on Table 1 at pages III-4 through III-6 of this report.

In the circumstances of the remaining Profile ID's the retirement rate method could not be used in the development of the average service lives. In these circumstances the average service lives were developed on judgment of Gannett Fleming that considered the current policies and outlook as determined during conversations with management personnel; and average service life estimates of previous studies of this Company and other electric companies. A number of these Profile ID's represented accounts that contained the least amount of investment in the system. 109 Profile ID's comprised over 95% of the BC Hydro investment (Primary Profile ID's). Approximately 250 Profile ID's comprise the investment of the remaining 5% of company investment. In a limited number of cases, the use of judgment served as the primary basis for the survivor curve estimate for the primary Profile ID's as sufficient information did not exist for use of the retirement rate method of average service life analysis. The average service lives determined based on the judgment of Gannett Fleming is summarized on Table 2 at pages III-8 through III-9 of this report.

AMPC wants to better understand the methodologies used to develop the last full depreciation study, to better assess its accuracy.

2.42.4 Specifically for accounts 25203 – Towers and 55101 - Overhead Conductors > 60 kV, as those accounts are identified in Table 2, please provide a current spreadsheet, in Excel format, that includes original costs of all material assets recorded in the accounts and vintage year. Please also provide in the spreadsheet the same information regarding assets that have retired from that account, including for each vintage the retirement that has occurred along with the year of retirement and asset age at retirement.

RESPONSE:

Attachment 1 to this response provides the requested information. The excel attachment includes the following three schedules with tab names as follows:

1. **Material assets_Mar31_19;**
2. **Material assets_Mar31_18; and**
3. **Retirements by yr and vintage.**

The two material assets schedules provide the asset class number and name, the asset number and description, the asset vintage (i.e., year of installation) and the original costs, accumulated depreciation and net book value for all assets with an

original cost greater than $10 million. A schedule is provided for March 31, 2019 that reflects current values restated for the fiscal 2019 adoption of IFRS. The March 31, 2018 schedule provides the balances as at March 31, 2018, prior to the IFRS adoption restatement.

The retirements schedule provides the requested information for the accounting retirements recognized since fiscal 2013 as shown in Attachment 1 to BC Hydro's response to AMPC IR 1.23.5. Prior to the adoption of the Prescribed Standards in fiscal 2013, BC Hydro did not record retirements on these asset classes in the accounting records.

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(Accessible by opening the Attachments Tab in Adobe)

42.0 Fiscal 2007 to Fiscal 2008 Revenue Requirements Application Depreciation Study

Reference (i): F07/F08 Revenue Requirements Application Depreciation Studies Appendix F, as referred to in BC Hydro Response to AMPC IR 1.23.4, pp. 25 – 27 and Tables 1 and 2 at pp. 31 – 38.

Reference (ii): Exhibit B-6, Attachment 1 to BC Hydro Response to AMPC IR 1.23.5 and F07/F08 Revenue Requirements Application Depreciation Studies Appendix F, as referred to in BC Hydro Response to AMPC IR 1.23.4 at p. 60

At p. 60 of the F07/F08 Revenue Requirements Application Depreciation Studies, BC Hydro recorded the following data for Account 22003, Powerhouse Integral with Dam: $747 million of exposures and less than $1 million of retirements in the history of the Account.

AMPC wants to better understand how the depreciation of this asset class has unfolded.

2.42.5 Please confirm the statement in the preamble for this IR, that at p. 60 of the F07/F08 Revenue Requirements Application Depreciation Studies, BC Hydro recorded the following data for Account 22003, Powerhouse Integral with Dam: $747 million of exposures and less than $1 million of retirements in the history of the Account. If not confirmed, please fully explain and provide an update of all recorded retirements in the history of this account.

RESPONSE:

Confirmed.

42.0 Fiscal 2007 to Fiscal 2008 Revenue Requirements Application Depreciation Study

Reference (i): F07/F08 Revenue Requirements Application Depreciation Studies Appendix F, as referred to in BC Hydro Response to AMPC IR 1.23.4, pp. 25 – 27 and Tables 1 and 2 at pp. 31 – 38.

Reference (ii): Exhibit B-6, Attachment 1 to BC Hydro Response to AMPC IR 1.23.5 and F07/F08 Revenue Requirements Application Depreciation Studies Appendix F, as referred to in BC Hydro Response to AMPC IR 1.23.4 at p. 60

At p. 60 of the F07/F08 Revenue Requirements Application Depreciation Studies, BC Hydro recorded the following data for Account 22003, Powerhouse Integral with Dam: $747 million of exposures and less than $1 million of retirements in the history of the Account.

AMPC wants to better understand how the depreciation of this asset class has unfolded.

2.42.5.1 With regard to the information set out in Attachment 1 to BC Hydro's response to AMPC IR 1.23.5, please confirm that over the eight year period 2011-2018, the total retirements from this account were $7,400, in 2013. If not confirmed, please fully explain and provide all recorded retirements from this account over this timeframe.

RESPONSE:

Confirmed.

42.0 Fiscal 2007 to Fiscal 2008 Revenue Requirements Application Depreciation Study

Reference (i): F07/F08 Revenue Requirements Application Depreciation Studies Appendix F, as referred to in BC Hydro Response to AMPC IR 1.23.4, pp. 25 – 27 and Tables 1 and 2 at pp. 31 – 38.

Reference (ii): Exhibit B-6, Attachment 1 to BC Hydro Response to AMPC IR 1.23.5 and F07/F08 Revenue Requirements Application Depreciation Studies Appendix F, as referred to in BC Hydro Response to AMPC IR 1.23.4 at p. 60

At p. 60 of the F07/F08 Revenue Requirements Application Depreciation Studies, BC Hydro recorded the following data for Account 22003, Powerhouse Integral with Dam: $747 million of exposures and less than $1 million of retirements in the history of the Account.

AMPC wants to better understand how the depreciation of this asset class has unfolded.

2.42.5.2 For account 22003, please provide the expected retirements that would occur over the period 2011-2018 based on the application of an Iowa 80-R4 based on the vintage of assets in service over this period 2011-2018, by year.

RESPONSE:

The calculated expected retirements based on an IOWA 80-R4 that would occur for asset class 22003 for the fiscal 2011 to fiscal 2018 balances provided in Attachment 1 to BC Hydro's response to AMPC IR 1.23.5 are included in the working Excel provided as Attachment 1 to this response.

The calculated expected retirements of original cost and net book value summarized by year from columns I and J of Attachment 1 are provided in the following table.

($ million)		
Fiscal Year	Theoretical Cost Retirements by Vintage	Theoretical NBV Retirements by Vintage
2011	(0.7)	(0.5)
2012	(1.3)	(0.9)
2013	(0.7)	(0.7)
2014	(0.7)	(0.6)
2015	(0.7)	(0.7)
2016	(1.3)	(1.2)
2017	(1.0)	(0.9)
2018	(1.0)	(0.8)

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(Accessible by opening the Attachments Tab in Adobe)

42.0 Fiscal 2007 to Fiscal 2008 Revenue Requirements Application Depreciation Study

Reference (i): F07/F08 Revenue Requirements Application Depreciation Studies Appendix F, as referred to in BC Hydro Response to AMPC IR 1.23.4, pp. 25 – 27 and Tables 1 and 2 at pp. 31 – 38.

Reference (ii): Exhibit B-6, Attachment 1 to BC Hydro Response to AMPC IR 1.23.5 and F07/F08 Revenue Requirements Application Depreciation Studies Appendix F, as referred to in BC Hydro Response to AMPC IR 1.23.4 at p. 60

At p. 60 of the F07/F08 Revenue Requirements Application Depreciation Studies, BC Hydro recorded the following data for Account 22003, Powerhouse Integral with Dam: $747 million of exposures and less than $1 million of retirements in the history of the Account.

AMPC wants to better understand how the depreciation of this asset class has unfolded.

2.42.6 Please provide an updated version of Attachment 1 to BC Hydro's response to AMPC IR 1.23.5 that splits accounts by type of asset (hydro-electric generator, thermal generation, transmission, distribution, etc.). Please include in this updated version approved additional asset componentization that occurred as a result of BC Hydro's proposal in the F12/F14 RRA, Appendix G (referenced in response to AMPC IR 1.23.4.4).

RESPONSE:

BC Hydro provides at the following link an update of Attachment 1 to BC Hydro's response to AMPC IR 1.23.5 that identifies the type of asset (function). The asset function (type of asset) is provided under the column heading "Function (type of asset)" (column C in each spreadsheet).

The list of asset classes (column A in each spreadsheet) includes the asset componentization that occurred as a result of BC Hydro's adoption of the Prescribed Standards as identified in the Fiscal 2012 to Fiscal 2014 Amended Revenue Requirements Application. The component asset classes added on adoption of the Prescribed Standards are provided below.

C22007	**Buildings - envelope**
C22009	**Building-HVAC Sys&Cp**
C23204	**Penstock -coatings**
C25206	**Pole str.crossarm>60**
C42004	**Major Maint.-Rewedge**
C47202	**Major Maint.-Gas Tur**
C52202	**Transf Distri-cutout**
C55305	**Cable, submarine,pum**
C55307	**Cable, Submarine >60**
C70104	**Instrumentation-Digi**
C70105	**Instrumentation-Anal**

These component asset classes were included in Attachment 1 to BC Hydro's response to AMPC IR 1.23.5.

43.0 Rate Forecast

Reference (i): Exhibit B-5, Attachment 2 to BC Hydro's Response to BCUC IR 1.5.1, pdf pp. 57-58

In this Attachment 2, at pdf pp. 57-58, BC Hydro sets out various forecasts for residential and commercial economic drivers, for F2019 - F2024.

Reference (ii): BCH ~ Application for the Review of the 2006 Integrated Electricity Plan and the Approval of the 2006 Long-Term Acquisition Plan - G-29-07 - 2007-03-15 - G-General

At p. 154 of this 2007 order, the Commission ordered that BC Hydro file a report showing "a financial forecast of BC Hydro’s rates in both real and nominal terms, for a minimum of ten years, but preferably 20 years. Input assumptions should be summarized in a concise, but comprehensive manner."

AMPC requires the same information in this proceeding, to allow the Commission to consider factors relevant to the Commission's exercise of its discretion in setting just and reasonable rates.

2.43.1 Please provide a report, as ordered by the Commission in 2007, that provides a forecast of BC Hydro's rates, in real and nominal terms, for the next 10 years. Please concisely identify and explain all input assumptions made.

RESPONSE:

The reference to the BCUC Order requiring BC Hydro to provide a long-term rate forecast relates to the May 11, 2007 BCUC Decision on BC Hydro’s 2006 Integrated Electricity Plan and 2006 Long Term Acquisition Plan, and does not relate to ongoing revenue requirement applications.

BC Hydro is unable to provide a 10-year rate forecast, as we currently do not have a financial forecast extending beyond fiscal 2024.

Please refer to Figure 1 on page 1 of the Evidentiary Update, which shows BC Hydro’s annual forecast bill increases and decreases for the five-year period ending in fiscal 2024. These annual nominal rate increases, and the real increases (adjusting for forecast inflation), are shown in the table below.

Per cent change to prior year	F2020	F2021	F2022	F2023	F2024
Annual bill increases / (decrease) - nominal	1.8	(1.0)	2.7	(0.3)	3.0
Annual bill increases / (decrease) - real	(0.4)	(3.0)	0.7	(2.2)	0.9

43.0 Rate Forecast

Reference (i): Exhibit B-5, Attachment 2 to BC Hydro's Response to BCUC IR 1.5.1, pdf pp. 57-58

Reference (iii): Exhibit B-1, Appendix C, Phase I Comprehensive Review of BC Hydro at p. 34 of the report

At pdf p. 1274, BC Hydro provides a five year rate forecast as follows:

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%

AMPC seeks to better understand BC Hydro's five year rate forecast.

2.43.2 Please provide an illustrative example of the necessary revenue increase (in total dollars) required to generate 40% equity in Site C (at current capital estimates and including the Site C regulatory account collection) within the long-term timeframe proposed to achieve the debt-to-equity target. Please provide the annual rate increase required for each year to achieve 40% equity of proposed Site C costs. Please provide the annual rate increase required to achieve 40% equity in Site C within (i) 10 years, and (ii) within 20 years.

RESPONSE:

BC Hydro considers its consolidated balance sheet when examining our debt:equity ratio and capital structure. As part of improving this capital structure, under current regulations, BC Hydro will not be paying a dividend to the Government of B.C. starting in fiscal 2020 and will not resume doing so until its debt:equity ratio is 60:40. As BC Hydro's current debt:equity ratio is approximately 82:18, it is not expected that dividends will resume until sometime

in the 2030s. The cessation of dividends enables BC Hydro to retain more cash to fund its cashflow requirements, which are largely driven by capital expenditures – this helps keep debt levels lower than they otherwise would be. BC Hydro's equity is built up over time through retained earnings.

BC Hydro does not consider debt or equity on a project by project basis; both are managed on an overall portfolio basis.

As a result of the above, BC Hydro is unable to provide the information requested in the question.

44.0 IFRS Conversion Impacts

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.23.6, pdf p. 311

At pdf p. 311, BC Hydro states as follows with regard to IFRS conversion impacts:

BC Hydro's IFRS conversion impacts are not finalized as they are subject to audit by BC Hydro's external auditor. Therefore, BC Hydro's response in the following table identifies the types of impacts resulting from the IFRS conversion but does not provide the amount of the impacts.

AMPC would like to better understand the potential IFRS conversion impacts and BC Hydro's process with regard to them.

2.44.1 When does BC Hydro anticipate its external auditor to finalize its audit?

RESPONSE:

The audit of BC Hydro's fiscal 2019 financial statements was finalized on June 12, 2019. BC Hydro's fiscal 2019 financial statements are included as part of BC Hydro's Annual Service Plan Report. The fiscal 2019 report can be found at the following link:

https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/BCHydro-Annual-Service-Plan-Report-2018-2019.pdf

44.0 IFRS Conversion Impacts

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.23.6, pdf p. 311

At pdf p. 311, BC Hydro states as follows with regard to IFRS conversion impacts:

> BC Hydro's IFRS conversion impacts are not finalized as they are subject to audit by BC Hydro's external auditor. Therefore, BC Hydro's response in the following table identifies the types of impacts resulting from the IFRS conversion but does not provide the amount of the impacts.

AMPC would like to better understand the potential IFRS conversion impacts and BC Hydro's process with regard to them.

2.44.2 Please provide a timeline for when BC Hydro anticipates finalization of IFRS conversion impacts and its proposed approach to review and approval before the BCUC for potential impact on rates.

RESPONSE:

BC Hydro finalized its conversion to IFRS in its fiscal 2019 financial statements. Please refer to BC Hydro's response to AMPC IR 2.44.1 for more information.

The IFRS conversion impacts and the timing of including such impacts in future rates is addressed in BC Hydro's response to AMPC IR 2.44.3.

44.0 IFRS Conversion Impacts

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.23.6, pdf p. 311

At pdf p. 311, BC Hydro states as follows with regard to IFRS conversion impacts:

> BC Hydro's IFRS conversion impacts are not finalized as they are subject to audit by BC Hydro's external auditor. Therefore, BC Hydro's response in the following table identifies the types of impacts resulting from the IFRS conversion but does not provide the amount of the impacts.

AMPC would like to better understand the potential IFRS conversion impacts and BC Hydro's process with regard to them.

2.44.3 Specifically what years will be impacted by IFRS conversion (including year of impact and years BC Hydro proposes to defer costs to)?

RESPONSE:

The impacts of BC Hydro's adoption of IFRS are stated in Note 24 of BC Hydro's fiscal 2019 financial statements, the link to which was provided in BC Hydro's response to AMPC IR 2.44.1.

As shown in Note 24, the specific years impacted by the adoption of IFRS are fiscal 2018 and fiscal 2019.

The adoption of IFRS resulted in a reduction of equity of $9 million which was attributed to the shareholder. In addition, as shown in Note 24 (g) net regulatory balances decreased by $315 million due to the adoption of IFRS 15 Revenue from Contract with Customers as part of the overall adoption of IFRS.

The $315 million reduction was recorded in the Cost of Energy Variance Accounts as discussed in section 8.13.2 of Chapter 8 of the Application. BC Hydro's proposed timing for recovery of the Cost of Energy Variance Accounts balances is discussed in section 7.7.1.1 of Chapter 7 of the Application.

45.0 Gains and Losses on Retirement

Reference (i): Exhibit B-5, BC Hydro Response to BCUC IR 1.161.7, pdf p. 1820

At pdf p. 1820, BC Hydro provides a variance comparison between 2018 and 2019 RRA forecast and actuals for Provision and Other:

$ million	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Dismantling costs	30.9	33.7	35.7	67.5	30.6	44.5	67.0	43.0
Gains/losses on mass asset retirements	31.0	33.5	33.1	34.0	33.6	33.6	35.9	38.7
Capital asset write-offs	7.9	13.5	7.0	9.7	6.1	6.1	8.0	8.1
Project write-offs	-	14.8	-	27.3	-	-	9.9	9.7
Non-cash provision expenses [1]	(5.3)	(31.3)	-	(3.1)	-	(2.0)	-	-
Other costs [2]	1.5	(0.7)	(14.8)	16.9	(18.6)	0.1	(12.6)	(12.5)
Total (Schedule 5.0 Line 110)	66.0	63.6	61.0	152.3	51.7	82.3	108.2	87.0

Reference (ii): Exhibit B-6, Attachment 1 to BC Hydro Response to AMPC IR 1.23.5

In Attachment 1 to this IR, BC Hydro provides additions/transfer, retirements and changes to Net Book Value from 2011 to 2018.

AMPC would like to better understand how additions/transfer and retirements are accounted for by BC Hydro, both theoretically and practically.

2.45.1 Please indicate if BC Hydro's approach to mass asset depreciation permits gains on retirement in addition to losses on retirement. If this is possible, please provide a detailed numerical example of how a gain on retirement of mass assets can arise (including transactions by year for the example asset in question).

RESPONSE:

Confirmed.

An example of how a gain may arise would be if the net book value of distribution transformers was $1,000 and they were sold for $1,200, a gain of $200 would be recognized in the income statement.

However, in substantially all cases, mass assets are retired with little or no proceeds and a loss on retirement is recognized unless the asset is fully depreciated.

45.0 Gains and Losses on Retirement

Reference (i): Exhibit B-5, BC Hydro Response to BCUC IR 1.161.7, pdf p. 1820

At pdf p. 1820, BC Hydro provides a variance comparison between 2018 and 2019 RRA forecast and actuals for Provision and Other:

$ million	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Dismantling costs	30.9	33.7	35.7	67.5	30.6	44.5	67.0	43.0
Gains/losses on mass asset retirements	31.0	33.5	33.1	34.0	33.6	33.6	35.9	38.7
Capital asset write-offs	7.9	13.5	7.0	9.7	6.1	6.1	8.0	8.1
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Reference (ii): Exhibit B-6, Attachment 1 to BC Hydro Response to AMPC IR 1.23.5

In Attachment 1 to this IR, BC Hydro provides additions/transfer, retirements and changes to Net Book Value from 2011 to 2018.

AMPC would like to better understand how additions/transfer and retirements are accounted for by BC Hydro, both theoretically and practically.

2.45.2 With reference to Excel file AMPC-1.23.5 Attachment 1, please confirm that the only instances where a retirement from Original Cost exceeded the retirement from Accumulated depreciation was where the retirement from gross cost was a reversal or other negative transaction (value added to original cost due to retirement, not subtracted), for example in account C34004 for F13. Please provide a description of the events that give rise to this type of transaction.

RESPONSE:

Not confirmed. Where a retirement is shown as a negative in the "retirements" column in the Original Cost section of the schedules, there is a partial or full retirement of the asset. Value is only added to the original cost of the asset in the following two circumstances:

- **There is a positive amount shown in the "additions/transfers" column indicating that there have been additional costs capitalized or there have been transfers of costs from another asset; or**

- **There is a positive amount shown in the "Prescribed Standards adjustments" column. The increases to the original cost of the asset are described below.**

The increase of $159.9 million in the original cost shown in the Prescribed Standards column for account C34004 is due to the recognition of an Electricity Purchase Agreement as a capital lease on adoption of the Prescribed Standards in fiscal 2013. Prior to the adoption of the Prescribed Standards, the Electricity Purchase Agreement was treated as an operating lease. The original cost of the capital lease recorded on adoption of the Prescribed Standards was $163.5 million. In the absence of the recognition of the capital lease, the original cost of account C34004 would have decreased by $3.6 million.

The increases to the original cost shown in the Prescribed Standards column for the asset classes in the table below are due to componentization adjustments on adoption of the Prescribed Standards. The componentization adjustments transfer balances from other "parent" asset classes to these component asset classes.

C22007	Buildings - envelope
C22009	Building-HVAC Sys&Cp
C23204	Penstock -coatings
C25206	Pole str.crossarm>60
C42004	Major Maint.-Rewedge
C47202	Major Maint.-Gas Tur
C52202	Transf Distri-cutout
C55305	Cable, submarine,pum
C55307	Cable, Submarine >60
C70104	Instrumentation-Digi
C70105	Instrumentation-Anal

45.0 Gains and Losses on Retirement

Reference (i): Exhibit B-5, BC Hydro Response to BCUC IR 1.161.7, pdf p. 1820

At pdf p. 1820, BC Hydro provides a variance comparison between 2018 and 2019 RRA forecast and actuals for Provision and Other:

$ million	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Dismantling costs	30.9	33.7	35.7	67.5	30.6	44.5	67.0	43.0
Gains/losses on mass asset retirements	31.0	33.5	33.1	34.0	33.6	33.6	35.9	38.7
Capital asset write-offs	7.9	13.5	7.0	9.7	6.1	6.1	8.0	8.1
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Non-cash provision expenses [1]	(5.3)	(31.3)	-	(3.1)	-	(2.0)	-	-
Other costs [2]	1.5	(0.7)	(14.8)	16.9	(18.6)	0.1	(12.6)	(12.5)
Total (Schedule 5.0 Line 110)	66.0	63.6	61.0	152.3	51.7	82.3	108.2	87.0

Reference (ii): Exhibit B-6, Attachment 1 to BC Hydro Response to AMPC IR 1.23.5

In Attachment 1 to this IR, BC Hydro provides additions/transfer, retirements and changes to Net Book Value from 2011 to 2018.

AMPC would like to better understand how additions/transfer and retirements are accounted for by BC Hydro, both theoretically and practically.

2.45.3 Please provide BC Hydro's definition of "mass asset" and indicate which, if any, of BC Hydro's assets are not included in this definition. If there are assets not included, please provide a description of the approach to depreciation and disposal for non-mass-asset property.

RESPONSE:

BC Hydro classifies assets as either individual ("I assets") or mass ("M assets") type. The definition for each type is provided below:

I assets: I assets are monitored individually and detailed records are maintained for each asset. These assets are low volume, high value items.

M Assets: M assets are tracked on a pool basis per vintage year by value only. These assets are typically high volume, low value items.

Both I and M assets are depreciated using the straight-line method based on average service lives. For I assets, on disposal or retirement, the net book value of a capital asset is expensed to gain/loss on disposal.

Please refer to Attachment 1 to this response for a listing of asset classes which identifies the asset type (i.e., I or M) for each class.

Numeric Listing of Asset Class Catalogue
Updated March 31, 2019

Asset Class	Asset Class Group	Asset Class Description	Asset Type	IFRS Est.Life (yrs.)	Dep'n Method	Salvage Rate (%)	Catalogue Section
C11501	115	LAND, OWNED IN FEE SIMPLE	I	0	S	0	Site /Structures/Improvements
C11602	116	EASEMENT / RIGHT-OF-WAY	I	0	S	0	Site /Structures/Improvements
C11604	116	LAND RIGHTS, OTHER	I	0	S	0	Site /Structures/Improvements
C11636	116	LAND RIGHTS,FINITE LIFE, 20YRS	I	20	S	0	Site /Structures/Improvements
C11640	116	WATER RIGHTS,FINITE LIFE, 40YRS	I	40	S	0	Site /Structures/Improvements
C11650	116	INFRASTRUCTURE RIGHTS (CONTRIBUTION)	I	35	S	0	Site /Structures/Improvements
C11801	118	RECREATION FACILITIES	M	20	S	0	Site /Structures/Improvements
C11901	119	SURFACING, YARD	M	35	S	0	Site /Structures/Improvements
C12001	120	TRAIL, CATERPILLAR	M	50	S	0	Site /Structures/Improvements
C12002	120	ROAD, PAVED / GRAVEL	M	50	S	0	Site /Structures/Improvements
C12005	120	ROADS & TRAILS, COMPOSITE POOL	M	50	S	0	Site /Structures/Improvements
C12101	121	TRACKS, RAILWAY	M	40	S	0	Site /Structures/Improvements
C12201	122	BRIDGE, WOOD	I	25	S	0	Site /Structures/Improvements
C12202	122	BRIDGE, STEEL	I	46	S	0	Site /Structures/Improvements
C12203	122	BRIDGE, CONCRETE	I	75	S	0	Site /Structures/Improvements
C12301	123	PAD, HELICOPTER	M	25	S	0	Site /Structures/Improvements
C12401	124	DRAINAGE SYSTEM, YARD	M	50	S	0	Site /Structures/Improvements
C12402	124	LANDSCAPING	M	25	S	0	Site /Structures/Improvements
C12501	125	WALL, RETAINING, STEEL	M	50	S	0	Site /Structures/Improvements
C12502	125	WALL, RETAINING, CONCRETE	M	100	S	0	Site /Structures/Improvements
C21001	210	DAM, EMBANKMENT / CONCRETE	I	100	S	0	Site /Structures/Improvements
C21002	210	DAM, CRIB, WOODEN	I	35	S	0	Site /Structures/Improvements
C21101	211	DIKE, PROTECTIVE	I	100	S	0	Site /Structures/Improvements
C21102	211	EROSION DONUT AND/OR BANK PROTECTION	I	25	S	0	Site /Structures/Improvements
C21103	211	DEBRIS/AVALANCHE DEFLECTOR	I	25	S	0	Site /Structures/Improvements
C21901	219	ROOFS	I	30	S	0	Site /Structures/Improvements
C22001	220	PLANT, CONCRETE OR STEEL	I	50	S	0	Site /Structures/Improvements
C22002	220	COMMERCIAL, CONCRETE OR STEEL	I	50	S	0	Site /Structures/Improvements
C22003	220	POWERHOUSE, INTEGRAL WITH DAM	I	100	S	0	Site /Structures/Improvements
C22004	220	BUILDING, WOOD	I	15	S	0	Site /Structures/Improvements
C22005	220	BUILDING, COMPOSITE POOL	I	60	S	0	Site /Structures/Improvements
C22006	220	EQUIPMENT SHELTER	I	10	S	0	Site /Structures/Improvements
C22007	220	BUILDINGS - ENVELOPE	I	30	S	0	Site /Structures/Improvements
C22009	220	BUILDINGS - HVAC SYSTEMS & COMPONENTS	I	15	S	0	Site /Structures/Improvements
C22101	221	OFFICE TRAILER/MOBILE HOME	I	23	S	0	Site /Structures/Improvements
C22211	222	LEASEHOLD IMPROVEMENTS	I	5	S	0	Site /Structures/Improvements
C22212	222	TENANT IMPROVEMENTS-10 YRS	I	10	S	0	Site /Structures/Improvements
C23001	230	SPILLWAY, SEPARATE FROM DAM	I	75	S	0	Site /Structures/Improvements
C23101	231	INTAKE STRUCTURE, POWER	I	100	S	0	Site /Structures/Improvements
C23201	232	PENSTOCK, STEEL	I	75	S	0	Site /Structures/Improvements
C23202	232	PENSTOCK, CONCRETE	I	100	S	0	Site /Structures/Improvements
C23203	232	PENSTOCK, WOOD	I	50	S	0	Site /Structures/Improvements
C23204	232	PENSTOCK - COATINGS	I	25	S	0	Site /Structures/Improvements
C23302	233	TANK, SURGE, STEEL	I	50	S	0	Site /Structures/Improvements
C23401	234	TAILRACE	I	100	S	0	Site /Structures/Improvements
C23501	235	CANAL	I	100	S	0	Site /Structures/Improvements
C23601	236	STOPLOGS, STEEL	I	60	S	0	Site /Structures/Improvements
C23602	236	STOPLOGS, WOOD	I	25	S	0	Site /Structures/Improvements
C23603	236	HOIST, GATE	I	55	S	0	Site /Structures/Improvements
C23604	236	GATE	I	40	S	0	Site /Structures/Improvements
C23605	236	GATES, EMBEDDED COMPONENTS	I	40	S	0	Site /Structures/Improvements
C23606	236	INLET VALVES, PENSTOCK & TURBINE	I	50	S	0	Site /Structures/Improvements
C23701	237	TRASH RACKS	I	50	S	0	Site /Structures/Improvements
C23801	238	CRANES	I	60	S	0	Site /Structures/Improvements
C23901	239	FISHWAYS, STEEL	I	50	S	0	Site /Structures/Improvements
C23902	239	FISHWAYS, CONCRETE	I	100	S	0	Site /Structures/Improvements
C24001	240	NAVIGATION LOCKS	I	100	S	0	Site /Structures/Improvements
C24002	240	NAVIGATION LOCK GATES - CONTROLS	I	20	S	0	Site /Structures/Improvements
C24003	240	NAVIGATION LOCK GATES - MOTOR	I	20	S	0	Site /Structures/Improvements
C24101	241	SLUICEWAY, SEPARATE FROM DAM	I	100	S	0	Site /Structures/Improvements
C24201	242	TUNNELS	I	100	S	0	Site /Structures/Improvements
C24301	243	SLOPE STABILIZATION	M	100	S	0	Site /Structures/Improvements
C24401	244	DOCK / WHARF	M	25	S	0	Site /Structures/Improvements
C24402	244	RAMP, BOAT/BARGE	I	20	S	0	Site /Structures/Improvements
C25101	251	STRUCTURE, SUPPORT, STEEL	M	65	S	0	Site /Structures/Improvements
C25102	251	STRUCTURE, SUPPORT, WOOD	M	30	S	0	Site /Structures/Improvements
C25201	252	POLE STRUCTURES < 60KV	M	50	S	0	Transmission/Distribution
C25202	252	POLE STRUCTURES > or = 60KV	M	50	S	0	Transmission/Distribution
C25203	252	TOWER, LATTICE / ASTHETIC	M	65	S	0	Transmission/Distribution
C25204	252	POLE STRUCTURE, COMPOSITE >= 60kV	M	65	S	0	Transmission/Distribution

C25205	252	TOWER - MAJOR OVERHAUL, CORROSION PROTE(	M	30	S	0	Transmission/Distribution
C25206	252	POLE STRUCTURE CROSS ARMS >= 60kV	M	30	S	0	Transmission/Distribution
C25301	253	FOUNDATIONS	M	40	S	0	Site /Structures/Improvements
C25401	254	DUCTS & TRENCHES	M	50	S	0	Site /Structures/Improvements
C25501	255	DUCTBANKS < 60KV	M	50	S	0	Transmission/Distribution
C25502	255	DUCTBANKS > or = 60KV	I	50	S	0	Transmission/Distribution
C25601	256	BARRIERS & ENCLOSURES	M	50	S	0	Site /Structures/Improvements
C25701	257	CAPACITOR, <60 KV	M	30	S	0	Transmission/Distribution
C30101	301	CASING, BOILER	I	30	S	0	Generating Equipment
C30102	301	INSULATION, BOILER	I	30	S	0	Generating Equipment
C30103	301	ROOF, BOILER	I	30	S	0	Generating Equipment
C30201	302	WATERWALL, BOILER	I	30	S	0	Generating Equipment
C30203	302	SUPERHEATER, HIGH TEMP	I	30	S	0	Generating Equipment
C30204	302	SUPERHEATER, LOW TEMP	I	30	S	0	Generating Equipment
C30205	302	REHEATER, BOILER	I	30	S	0	Generating Equipment
C30206	302	DESUPERHEATER/ATTEMPERATOR	I	10	S	0	Generating Equipment
C30301	303	HEADER / DRUM	I	40	S	0	Generating Equipment
C30401	304	VALVES, SAFETY	I	30	S	0	Generating Equipment
C30501	305	PIPING, HIGH PRESSURE	I	40	S	0	Generating Equipment
C30601	306	FAN, FORCED DRAFT	I	30	S	0	Generating Equipment
C30602	306	BREACHING / FLUE SYSTEM	I	30	S	0	Generating Equipment
C30603	306	STACK, FLUE GASES	I	30	S	0	Generating Equipment
C30604	306	PREHEATER, AIR	I	30	S	0	Generating Equipment
C30605	306	BURNER, FUEL	I	15	S	0	Generating Equipment
C30606	306	INSTRUMENTATION, BOILER	I	30	S	0	Generating Equipment
C30608	306	CONTROL SYSTEM, FEEDWATER	I	15	S	0	Generating Equipment
C30609	306	SEALS, CROWN	I	30	S	0	Generating Equipment
C30610	306	CONTROL SYSTEM, FUEL	I	15	S	0	Generating Equipment
C30611	306	DESUPERHEATER SYSTEM	I	15	S	0	Generating Equipment
C30612	306	REFRACTORY, BOILER	I	20	S	0	Generating Equipment
C30613	306	BOILER, PACKAGE	I	30	S	0	Generating Equipment
C30701	307	EQUIPMENT, WATER TREATMENT	M	40	S	0	Generating Equipment
C30801	308	TRANSFER SYSTEM, AMMONIA	I	20	S	0	Generating Equipment
C30802	308	WATER DELUGE SYSTEM, AMMONIA	I	30	S	0	Generating Equipment
C30803	308	VAPOURISER, AMMONIA	I	20	S	0	Generating Equipment
C30804	308	COMPRESSOR, VAPOUR, AMMONIA	I	15	S	0	Generating Equipment
C30805	308	PIPING SYSTEM, AMMONIA	I	30	S	0	Generating Equipment
C30901	309	MONITORING EQUIP., CEM	I	10	S	0	Generating Equipment
C30902	309	REPORTING SYSTEM, CEM	I	10	S	0	Generating Equipment
C30903	309	DELIVERY SYSTEM,AMMONIA,SCR	I	30	S	0	Generating Equipment
C30904	309	CATALYST, SCR	I	10	S	0	Generating Equipment
C31001	310	WATER INTAKE/DISCHARGE STRUCT	I	50	S	0	Generating Equipment
C31002	310	PROTECTION, CATHODIC	I	20	S	0	Generating Equipment
C31003	310	GATES, INLET/OUTLET	I	30	S	0	Generating Equipment
C31004	310	SCREENS, INTAKE	I	20	S	0	Generating Equipment
C31005	310	CONDUIT, INTAKE/DISCHARGE	I	50	S	0	Generating Equipment
C31006	310	VALVES	I	30	S	0	Generating Equipment
C31007	310	TURBINE/PENSTOCK INLET VALVES	I	50	S	0	Generating Equipment
C33001	330	HEAT EXCHANGER, SHELL & TUBE	I	30	S	0	Generating Equipment
C33002	330	PUMP AND MOTOR	I	30	S	0	Generating Equipment
C33004	330	CONDENSER, BOILER	I	30	S	0	Generating Equipment
C33005	330	CONDENSER AIR REMOVAL SYSTEM	I	15	S	0	Generating Equipment
C34002	340	CASING, CYLINDER	I	30	S	0	Generating Equipment
C34004	340	TURBINE, COMPOSITE POOL	I	30	S	0	Generating Equipment
C34005	340	COILS, STATOR	I	30	S	0	Generating Equipment
C34006	340	ROTOR, GENERATOR	I	30	S	0	Generating Equipment
C34007	340	GENERATOR, COMPOSITE POOL	I	30	S	0	Generating Equipment
C34008	340	SUPERVISORY SYSTEM, TURBINE	I	20	S	0	Generating Equipment
C34009	340	COOLING SYSTEM, HYDROGEN	I	30	S	0	Generating Equipment
C34013	340	GENERATOR OIL COOLERS	I	15	S	0	Generating Equipment
C34015	340	TURBINE BLADE SETS	I	15	S	0	Generating Equipment
C41001	410	RUNNER / WATER WHEEL	I	50	S	0	Generating Equipment
C41002	410	GOVERNOR SYSTEM, TURBINE	I	50	S	0	Generating Equipment
C41003	410	CASING, EMBEDDED/SPIRAL CASE	I	50	S	0	Generating Equipment
C41004	410	SHAFT, TURBINE	I	50	S	0	Generating Equipment
C41005	410	GATES, WICKET	I	50	S	0	Generating Equipment
C41006	410	COVER, HEAD	I	50	S	0	Generating Equipment
C41007	410	TURBINE, HYDRO, COMP. POOL	I	50	S	0	Generating Equipment
C41008	410	BEARINGS FOR WICKET GATE	I	25	S	0	Generating Equipment
C41501	415	DRAFT TUBE WATER DEPRESSION SY	I	25	S	0	Generating Equipment
C41601	416	UNWATERING SYSTEM	I	25	S	0	Generating Equipment
C41701	417	TURBINE AIR INJECTION BLOWER	I	25	S	0	Generating Equipment
C42001	420	COILS, STATOR	I	30	S	0	Generating Equipment
C42002	420	ROTOR, GENERATOR	I	50	S	0	Generating Equipment
C42003	420	GENERATOR, COMPOSITE POOL	I	50	S	0	Generating Equipment

C42004	420	MAJOR MAINTENANCE - REWEDGING	I	25	S	0	Generating Equipment
C42101	421	EXCITER, ROTARY	I	40	S	0	Generating Equipment
C42102	421	EXCITER, STATIC	I	40	S	0	Generating Equipment
C42104	421	EXCITER, COMPOSITE POOL	I	40	S	0	Generating Equipment
C42201	422	RESISTOR, LOAD-BREAKING	I	25	S	0	Generating Equipment
C42501	425	PIPING, WATER COOLING SYSTEM	M	40	S	0	Generating Equipment
C42502	425	MONITORING SYSTEM, COOLING	I	20	S	0	Generating Equipment
C45100	451	LEASED WIND TURBINE	I	25	S	0	Generating Equipment
C45101	451	LEASED SUBSTATION	I	35	S	0	Generating Equipment
C45102	451	LEASED DISTRIBUTION LINES	I	40	S	0	Generating Equipment
C45103	451	LEASED TRANSMISSION LINES	I	50	S	0	Generating Equipment
C45104	451	LEASED ROADS & CIVIL	I	50	S	0	Generating Equipment
C45120	451	LEASED THERMAL GENERATING PLANT	I	30	S	0	Generating Equipment
C46501	465	COOLING SYSTEM, WATER	I	15	S	0	Generating Equipment
C46502	465	ENGINE, INTERNAL COMBUSTION	I	25	S	0	Generating Equipment
C46701	467	HEAT EXCHANGER	I	30	S	0	Generating Equipment
C47101	471	EXHAUST STRUCTURE	M	25	S	0	Generating Equipment
C47201	472	TURBINE, GAS	I	25	S	0	Generating Equipment
C47202	472	MAJOR MAINTENANCE - GAS TURBINES	I	7	S	0	Generating Equipment
C47401	474	FUEL SYSTEM	M	40	S	0	Generating Equipment
C48001	480	COILS, STATOR	I	40	S	0	Generating Equipment
C48002	480	ROTOR, GENERATOR	I	40	S	0	Generating Equipment
C48003	480	GENERATOR, COMPOSITE POOL	I	30	S	0	Generating Equipment
C48004	480	GENERATOR, DIESEL	I	30	S	0	Generating Equipment
C49001	490	PUMP	I	20	S	0	Generating Equipment
C49002	490	MOTOR	I	30	S	0	Generating Equipment
C49101	491	FAN & MOTOR	I	30	S	0	Generating Equipment
C49201	492	VACUUM SYSTEM	I	25	S	0	Generating Equipment
C51001	510	CONDENSOR,SYNCHRONOUS,ROTARY	I	50	S	0	Generating Equipment
C51002	510	CONDENSOR,SYNCHRONOUS,STATIC	I	40	S	0	Generating Equipment
C52101	521	TRANSFORMER,GENERATOR,STEPUP	I	40	S	0	Switchyard Equipment
C52102	521	TRANSFORMER, AUTO, BULK SYS	I	45	S	0	Switchyard Equipment
C52103	521	TRANSFORMER, POWER - > 100MVA	I	40	S	0	Switchyard Equipment
C52104	521	TRANSFORMER, POWER - < 100MVA	I	45	S	0	Switchyard Equipment
C52105	521	TRANSFORMER, STATION SERVICE	I	40	S	0	Switchyard Equipment
C52106	521	TRANSFORMER, POWER, COMP POOL	I	45	S	0	Switchyard Equipment
C52201	522	TRANSFORMER, DISTRIBUTION	M	35	S	0	Transmission/Distribution
C52202	522	DISTRIBUTION CUTOUTS	M	25	S	0	Transmission/Distribution
C52301	523	REACTOR, OIL	I	25	S	0	Switchyard Equipment
C52302	523	REACTOR, DRY TYPE	I	40	S	0	Switchyard Equipment
C52303	523	REACTOR, COMPOSITE POOL	I	40	S	0	Switchyard Equipment
C52401	524	OIL, 69 KV & ABOVE	I	40	S	0	Switchyard Equipment
C52402	524	GAS, SF6, 69 KV & ABOVE	I	40	S	0	Switchyard Equipment
C52403	524	OIL, < 69 KV	I	35	S	0	Switchyard Equipment
C52404	524	TRANSFORMER,CURRENT,ENCAPS.	I	45	S	0	Switchyard Equipment
C52405	524	TRANSFORMER,CURRENT,COMP. POOL	I	50	S	0	Switchyard Equipment
C52406	524	TRANSFORMER, COMB VT & CT	I	40	S	0	Switchyard Equipment
C52501	525	TRANSFORMER,VOLTAGE,CAPACITOR	M	35	S	0	Switchyard Equipment
C52502	525	TRANSFORMER,VOLTAGE,OIL-FILL	M	40	S	0	Switchyard Equipment
C52503	525	TRANSFORMER,VOLTAGE,GAS-FILL	M	50	S	0	Switchyard Equipment
C52504	525	TRANSFORMER,VOLTAGE,ENCAPS.	M	45	S	0	Switchyard Equipment
C52505	525	TRANSFORMER,VOLT,COMP. POOL	M	40	S	0	Switchyard Equipment
C52601	526	MOBILE SUBSTATIONS	I	25	S	0	Switchyard Equipment
C53101	531	CAPACITOR, SHUNT	I	30	S	0	Switchyard Equipment
C53201	532	CAPACITOR, SERIES	I	35	S	0	Switchyard Equipment
C53202	532	METAL OXIDE VARISTER (MOV)	I	35	S	0	Switchyard Equipment
C53301	533	CAPACITOR, COUPLING	I	35	S	0	Switchyard Equipment
C54101	541	BREAKER,AIR/MAGNETIC	I	20	S	0	Switchyard Equipment
C54102	541	BREAKER,GAS(SF6)12 / 25 KV	I	30	S	0	Switchyard Equipment
C54103	541	BREAKER,BULK/MIN OIL/AIR BLAST	I	45	S	0	Switchyard Equipment
C54104	541	BREAKER,GAS(SF6), 69 TO 500 KV	I	45	S	0	Switchyard Equipment
C54105	541	BREAKERS, COMPOSITE POOL	I	35	S	0	Switchyard Equipment
C54201	542	USE INDIVIDUAL DISCONNECT CAUS	M	40	S	0	Switchyard Equipment
C54202	542	DISCONNECT, 1 PHASE, HOOKSTICK	I	30	S	0	Switchyard Equipment
C54203	542	DISCONNECT, 3 PHASE, 12/25KV	I	35	S	0	Switchyard Equipment
C54204	542	DISCONNECT, 3 PHASE, 69-230KV	I	35	S	0	Switchyard Equipment
C54205	542	DISCONNECT, 3 PHASE, 500KV	I	35	S	0	Switchyard Equipment
C54401	544	SWITCHGEAR, METALCLAD	I	30	S	0	Switchyard Equipment
C54501	545	CIRCUIT RECLOSER	I	40	S	0	Switchyard Equipment
C54601	546	CIRCUIT SWITCHER	I	30	S	0	Switchyard Equipment
C55101	551	CONDUCTOR, OVERHEAD > or = 60 KV	M	60	S	0	Transmission/Distribution
C55102	551	CONDUCTOR, OVERHEAD < 60 KV	M	45	S	0	Transmission/Distribution
C55103	551	LINE DISCONNECT SWITCHES	M	25	S	0	Transmission/Distribution
C55104	551	OCAS - OVERHEAD COLLISION AVOIDANCE SYSTE	I	5	S	0	Transmission/Distribution
C55201	552	OVERHEAD CONDUCTOR SERVICES	M	45	S	0	Transmission/Distribution

C55202	552 UG CONDUCTOR SERVICES < 60 Kv	M	45 S	0	Transmission/Distribution
C55301	553 CABLE,UNDERGROUND <60KV	M	40 S	0	Transmission/Distribution
C55302	553 CABLE,UNDERGROUND > or = 60KV	I	40 S	0	Transmission/Distribution
C55303	553 CABLE,SUBMARINE > or = 60 KV	I	45 S	0	Transmission/Distribution
C55304	553 CABLE, SUBMARINE < 60 Kv	M	35 S	0	Transmission/Distribution
C55305	553 CABLE, SUBMARINE, PUMPING PLANT & INSTRUME	I	25 S	0	Transmission/Distribution
C55307	553 CABLE, SUBMARINE >= 60 KV -MAJOR INSPECTION	I	5 S	0	Transmission/Distribution
C55308	553 UG CABLE MONITORING SYSTEM >= 60 Kv (TRANSI	I	10 S	0	Transmission/Distribution
C55401	554 BUSWORK & STATION CONDUCTOR	M	60 S	0	Switchyard Equipment
C55501	555 GROUNDING SYSTEMS	M	40 S	0	Switchyard Equipment
C56001	560 INSULATORS	M	55 S	0	Switchyard Equipment
C57001	570 ARRESTOR, SURGE	M	30 S	0	Switchyard Equipment
C58001	580 CONVERTER	I	30 S	0	Switchyard Equipment
C58002	580 INVERTER	I	30 S	0	Switchyard Equipment
C58101	581 VAR COMPENSATOR, STATIC	I	40 S	0	Switchyard Equipment
C58201	582 RESISTOR, ANODE DAMPING	I	25 S	0	Switchyard Equipment
C58901	589 POWER SUPPLY, SOLAR PANEL	M	10 S	0	Communication
C59001	590 POWER SUPPLY, UNINTERRUPTIBLE	I	15 S	0	Communication
C59101	591 REGULATOR, FEEDER CIRCUIT	I	30 S	0	Switchyard Equipment
C59201	592 CHARGER SYSTEM, BATTERY	M	20 S	0	Switchyard Equipment
C59301	593 STORAGE BATTERIES, BANK	M	20 S	0	Switchyard Equipment
C59401	594 METERS, BILLING, DISTRIBUTION	M	25 S	0	Transmission/Distribution
C59402	594 METERS, TRANSMISSION	I	30 S	0	Transmission/Distribution
C59403	594 AUTOMATED METERS, DISTRIBUTION	M	20 S	0	Transmission/Distribution
C59501	595 STREET LIGHTS,DIST. , OWNED	M	40 S	0	Transmission/Distribution
C59502	595 STREET LIGHTS,DIST. , LEASED	M	40 S	0	Transmission/Distribution
C59503	595 STREETLIGHT LED	M	20 S	0	Transmission/Distribution
C59601	596 METERING, DC, TROLLEYS	M	35 S	0	Switchyard Equipment
C61001	610 FENCING	M	25 S	0	Site /Structures/Improvements
C61101	611 ALARM/SECURITY SYSTEM	M	20 S	0	Site /Structures/Improvements
C61201	612 BOOMS, FLOATING	M	15 S	0	Site /Structures/Improvements
C61202	612 BOOMS, FLOATING CEDAR	I	25 S	0	Site /Structures/Improvements
C61203	612 BOOMS, OIL CONTAINMENT	I	15 S	0	Site /Structures/Improvements
C62001	620 FIRE PROTECTION SYSTEM	M	25 S	0	Switchyard Equipment
C62501	625 FIREFIGHTING EQUIPMENT	M	25 S	0	Miscellaneous
C63001	630 EXERCISE EQUIPMENT	M	5 S	0	Miscellaneous
C65001	650 PROTECTION & CONTROL EQUIPMENT AND RELAY	M	20 S	0	Switchyard Equipment
C65101	651 FAULT LOCATING& REPORTING	M	20 S	0	Switchyard Equipment
C67001	670 LINER, PVC, SPILL CONTAINMENT	M	35 S	0	Site /Structures/Improvements
C67003	670 CONTAINMENT FACILITY, CONCRETE	I	50 S	0	Site /Structures/Improvements
C67004	670 SPILL POND, NATURAL	M	25 S	0	Site /Structures/Improvements
C67005	670 OIL SPILL CONTAINMENT	I	35 S	0	Site /Structures/Improvements
C67006	670 CONTAINMENT SYSTEM, OIL SPILL	M	35 S	0	Site /Structures/Improvements
C68001	680 CARRIER SYSTEM, POWER LINE	M	15 S	0	Communication
C68101	681 ANTENNAE & WAVEGUIDE,MICROWAVE	M	20 S	0	Communication
C68201	682 CONTROL CENTRE (MASTER EQUIP)	I	12 S	0	Communication
C68202	682 TERMINAL UNIT,REMOTE (SLAVE)	M	20 S	0	Communication
C68203	682 INTEGRATED CONTROL/DATA(ICDA)	I	5 S	0	Communication
C68204	682 DISTRIBUTED CONTROL SYSTEM	I	20 S	0	Communication
C68205	682 GLOBAL POSITIONING EQUIPMENT	I	10 S	0	Communication
C68301	683 RADIO,MICROWAVE,ANALOG	M	35 S	0	Communication
C68302	683 RADIO,MICROWAVE,DIGITAL	I	35 S	0	Communication
C68401	684 MULTIPLEX DEVICE, ANALOG	M	5 S	0	Communication
C68402	684 MULTIPLEX DEVICE, DIGITAL	I	20 S	0	Communication
C68501	685 RADIO SYSTEMS, UHF/VHFF	M	35 S	0	Communication
C68502	685 MOBILE DISPATCH SYSTEM	I	5 S	0	Communication
C68503	685 RADIO EQUIPMENT, PROTECTION	M	25 S	0	Communication
C68601	686 PROTECTION TONE SYSTEM	M	20 S	0	Communication
C68602	686 DIGITAL TELEPROTECTION SYSTEM	M	20 S	0	Communication
C68701	687 WAVE TRAP / LINE TRAP	M	20 S	0	Communication
C68801	688 FIBRE OPTIC SYSTEM	M	20 S	0	Communication
C68901	689 TELEPHONE EQUIPMENT, PBX/PAX	I	20 S	0	Communication
C68903	689 TEL EQUIP, MONITORING SYSTEM	I	5 S	0	Communication
C68904	689 TELEPHONE SYSTEM, CELLULAR	I	5 S	0	Communication
C70001	700 CABLE, ENTRANCE PROTECTION	M	20 S	0	Communication
C70101	701 HYDROMETEOROLOGICAL EQUIPMENT	M	15 S	0	Miscellaneous
C70102	701 ACCELEROMETERS	I	20 S	0	Miscellaneous
C70103	701 SEISMIC MONITORING EQUIPMENT	I	20 S	0	Miscellaneous
C70104	701 INSTRUMENTATION - DIGITAL	I	25 S	0	Miscellaneous
C70105	701 INSTRUMENTATION - ANALOGUE	I	40 S	0	Miscellaneous
C73001	730 COOLING SYSTEM, AIR	I	25 S	0	Switchyard Equipment
C74001	740 MOTOR-GENERATOR SETS	I	35 S	0	Switchyard Equipment
C75101	751 DRIER, AIR	M	25 S	0	Switchyard Equipment
C75102	751 PIPING/VALVING, STEEL	M	20 S	0	Switchyard Equipment
C75103	751 PIPING, STAINLESS STEEL	M	40 S	0	Switchyard Equipment

C75104	751	COMPRESSOR, AIR	I	25	S	0	Switchyard Equipment
C75201	752	TANKS, STEEL, AIR/FUEL	M	30	S	0	Site /Structures/Improvements
C75202	752	TANK,FIBRGLAS,DBL BOTTOM,FUEL	I	30	S	0	Site /Structures/Improvements
C75203	752	TANK,AIR-STAINLESS/OIL-STEEL	I	30	S	0	Site /Structures/Improvements
C75204	752	TANKS, CONCRETE	I	30	S	0	Site /Structures/Improvements
C75205	752	TANKS, WOOD	I	25	S	0	Site /Structures/Improvements
C75301	753	WATER SUPPLY SYSTEM	M	40	S	0	Site /Structures/Improvements
C80101	801	COMPUTER,HARDWARE,MICRO (PC)	M	4	S	0	Computers
C80103	801	COMPUTER,HARDWARE,INPUT/OUTPUT	M	5	S	0	Computers
C80105	801	LAPTOPS	M	3	S	0	Computers
C80204	802	STORAGE DEVICE, DISC/TAPE	M	5	S	0	Computers
C80302	803	SOFTWARE, ENTERPRISE SYSTEMS	I	10	S	0	Computers
C80303	803	SOFTWARE, MID-RANGE SYSTEMS	I	5	S	0	Computers
C80305	803	SOFTWARE UPGRD,ENTERPRISE SYS	I	2	S	0	Computers
C80314	803	PC SOFTWARE	M	4	S	0	Computers
C80318	803	SOFTWARE 5 YR LIFE - INTERNALLY DEVELOPED	I	5	S	0	Computers
C80319	803	SOFTWARE 10 YR LIFE - INTERNALLY DEVELOPED	I	10	S	0	Computers
C80401	804	SIMULATOR, TRAINING	I	5	S	0	Miscellaneous
C80501	805	PREMISE CABLING	M	7	S	0	Computers
C80502	805	ROUTERS	M	5	S	0	Computers
C80503	805	SWITCHES	M	5	S	0	Computers
C80504	805	SERVERS	M	5	S	0	Computers
C80508	805	MISC. NETWORK EQUIP.	M	4	S	0	Computers
C81001	810	AUTOMOBILES	I	8	S	20	Vehicles/Work Equipment
C81101	811	TRUCKS < 1 TON 2 WHEEL DRIVE	I	8	S	20	Vehicles/Work Equipment
C81201	812	TRUCKS < 1 TON 4 WHEEL DRIVE	I	8	S	20	Vehicles/Work Equipment
C81301	813	TRUCKS >= 1 TON 2 WHEEL DRIVE	I	13	S	15	Vehicles/Work Equipment
C81302	813	TRUCKS >= 1 TON 2 WHEEL DRIVE (UNDERPERFO	I	13	S	5	Vehicles/Work Equipment
C81401	814	TRUCKS >= 1 TON 4 WHEEL DRIVE	I	13	S	25	Vehicles/Work Equipment
C81501	815	TRUCKS >= 1 TON 6 WHEEL DRIVE	I	12	S	10	Vehicles/Work Equipment
C81601	816	TRACTOR, HIGHWAY	I	9	S	10	Vehicles/Work Equipment
C81701	817	AERIAL DEVICE	I	13	S	10	Vehicles/Work Equipment
C81702	817	LINE / SERVICE / VAN BODY	I	15	S	15	Vehicles/Work Equipment
C81703	817	DERRICKS / DIGGERS	I	15	S	20	Vehicles/Work Equipment
C81704	817	RIDE-A-RAILS	I	25	S	15	Vehicles/Work Equipment
C82501	825	FORKLIFT / PALLET JACK	I	20	S	20	Vehicles/Work Equipment
C82502	825	SNOW VEHICLE	I	20	S	40	Vehicles/Work Equipment
C82503	825	SWEEPER	I	15	S	15	Vehicles/Work Equipment
C82504	825	LOADER / BACKHOE	I	17	S	45	Vehicles/Work Equipment
C82505	825	TRAILER, REEL/POLE/UTILITY	I	20	S	10	Vehicles/Work Equipment
C82506	825	WELDER, MOBILE, SELF-POWERED	I	15	S	15	Vehicles/Work Equipment
C82507	825	COMPRESSOR,MOBILE,SELF-POWERED	I	15	S	10	Vehicles/Work Equipment
C82508	825	CHIPPER	I	15	S	15	Vehicles/Work Equipment
C82509	825	TRACTOR	I	10	S	30	Vehicles/Work Equipment
C82510	825	RAILCARS	M	35	S	0	Vehicles/Work Equipment
C82512	825	REGEN PLAN, XFORMER OIL	I	15	S	0	Vehicles/Work Equipment
C82513	825	MANLIFT	I	15	S	0	Vehicles/Work Equipment
C82514	825	ALL TERRAIN VEHICLE	I	8	S	15	Vehicles/Work Equipment
C82550	825	TOOLS/WORK EQUIPMENT, MISC	M	15	S	0	Vehicles/Work Equipment
C82601	826	TEST/CALIBRATION EQUIPMENT	I	15	S	0	Vehicles/Work Equipment
C82603	826	MANUFACTURING/TEST EQUIPMENT	M	15	S	0	Vehicles/Work Equipment
C83001	830	BOAT	M	15	S	15	Vehicles/Work Equipment
C83002	830	BOAT, TUGBOAT	I	20	S	0	Vehicles/Work Equipment
C85001	850	FURNITURE & EQUIPMENT, OFFICE	M	15	S	0	Miscellaneous
C87001	870	PCB SOLIDS DESTRUCTION PLANT	I	5	S	0	Miscellaneous
C88001	880	LAB EQUIPMENT, HI-PWR LAB	M	20	S	0	Miscellaneous
C88002	880	LAB EQUIPMENT, MISC	M	15	S	0	Miscellaneous
C88003	880	LAB EQUIPMENT, HI-PWR LAB	I	15	S	0	Miscellaneous
C89501	895	ANIMAL PREVENTATIVE EQUIPMENT	M	20	S	0	Miscellaneous
C90004	900	WATER USE PLANS	I	10	S	0	Miscellaneous

45.0 Gains and Losses on Retirement

Reference (i): Exhibit B-5, BC Hydro Response to BCUC IR 1.161.7, pdf p. 1820

At pdf p. 1820, BC Hydro provides a variance comparison between 2018 and 2019 RRA forecast and actuals for Provision and Other:

$ million	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Dismantling costs	30.9	33.7	35.7	67.5	30.6	44.5	67.0	43.0
Gains/losses on mass asset retirements	31.0	33.5	33.1	34.0	33.6	33.6	35.9	38.7
Capital asset write-offs	7.9	13.5	7.0	9.7	6.1	6.1	8.0	8.1
Project write-offs	-	14.8	-	27.3	-	-	9.9	9.7
Non-cash provision expenses [1]	(5.3)	(31.3)	-	(3.1)	-	(2.0)	-	-
Other costs [2]	1.5	(0.7)	(14.8)	16.9	(18.6)	0.1	(12.6)	(12.5)
Total (Schedule 5.0 Line 110)	66.0	63.6	61.0	152.3	51.7	82.3	108.2	87.0

Reference (ii): Exhibit B-6, Attachment 1 to BC Hydro Response to AMPC IR 1.23.5

In Attachment 1 to this IR, BC Hydro provides additions/transfer, retirements and changes to Net Book Value from 2011 to 2018.

AMPC would like to better understand how additions/transfer and retirements are accounted for by BC Hydro, both theoretically and practically.

2.45.4 Please provide a calculation of the depreciation expense that would arise for assets in service in F2017 and F2018 if depreciation had not been stopped for assets that have been fully amortized (e.g., under traditional group accounting where gains and losses are not booked in the year experienced and over-depreciation of any given asset within the group is permissible). If this is not possible, please provide an order of magnitude estimate of the value.

RESPONSE:

BC Hydro assumes that the reference to traditional group accounting in the question is referring to the equal life group accounting method. BC Hydro is not able to provide a calculation of the depreciation expense that would arise for assets in fiscal 2017 and fiscal 2018 under equal life group accounting because BC Hydro does not use and has limited familiarity in the application of equal life group accounting methods. BC Hydro would require the assistance of an external expert in equal life group accounting method in order to perform such a calculation or to even provide an order of magnitude estimate.

45.0 Gains and Losses on Retirement

Reference (i): Exhibit B-5, BC Hydro Response to BCUC IR 1.161.7, pdf p. 1820

At pdf p. 1820, BC Hydro provides a variance comparison between 2018 and 2019 RRA forecast and actuals for Provision and Other:

$ million	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
Dismantling costs	30.9	33.7	35.7	67.5	30.6	44.5	67.0	43.0
Gains/losses on mass asset retirements	31.0	33.5	33.1	34.0	33.6	33.6	35.9	38.7
Capital asset write-offs	7.9	13.5	7.0	9.7	6.1	6.1	8.0	8.1
Project write-offs	-	14.8	-	27.3	-	-	9.9	9.7
Non-cash provision expenses [1]	(5.3)	(31.3)	-	(3.1)	-	(2.0)	-	-
Other costs [2]	1.5	(0.7)	(14.8)	16.9	(18.6)	0.1	(12.6)	(12.5)
Total (Schedule 5.0 Line 110)	66.0	63.6	61.0	152.3	51.7	82.3	108.2	87.0

Reference (ii): Exhibit B-6, Attachment 1 to BC Hydro Response to AMPC IR 1.23.5

In Attachment 1 to this IR, BC Hydro provides additions/transfer, retirements and changes to Net Book Value from 2011 to 2018.

AMPC would like to better understand how additions/transfer and retirements are accounted for by BC Hydro, both theoretically and practically.

2.45.5 Please provide a schedule that breaks down forecast gains/losses on mass asset retirements and dismantlement costs by asset account for test years 2020 and 2021. Please explain the forecast methodology for these two costs. If test year forecast methodology relies on actuals, please provide all relevant years and supporting calculations.

RESPONSE:

Mass Asset Retirements

Please refer to Attachment 1 to this response for fiscal 2020 and fiscal 2021 forecast mass asset retirement losses by asset class. The totals correspond to the "Gains/losses on mass asset retirements" line shown in the preamble to the question.

The mass asset retirement losses are forecast primarily using retirement assumptions based on Iowa survivor curves. The retirement loss forecasts calculated using Iowa curve assumptions for distribution transformers (i.e., Asset

Class C52201) and distribution cutouts (i.e., Asset Class C52202) were adjusted to reflect average loss history for the past five years by multiplying the fiscal 2020 and fiscal 2021 Iowa curve based forecast by the ratio of the 5 year average losses divided by the fiscal 2019 Iowa based forecast losses. The five year loss history for the accounts is provided in the table below.

($ million)

Asset Class	Asset Class Description	F2014	F2015	F2016	F2017	F2018	Average
C52201	TRANSFORMER, DISTRIBUTION	(4.7)	(6.0)	(7.1)	(7.8)	(7.1)	(6.5)
C52202	DISTRIBUTION CUTOUTS	(1.6)	(1.1)	(0.9)	(1.3)	(1.5)	(1.3)

In addition, the forecast losses on retirements of streetlight assets (i.e., Asset Class C59501) was adjusted to reflect forecast partial retirements associated with the LED streetlight replacements as discussed in section 8.2.2 of Chapter 8 of the Application.

Dismantling Costs

BC Hydro does not plan or track dismantling costs by asset class as BC Hydro does not accrue negative salvage over the life of the assets.

Dismantling costs are difficult to forecast because they are impacted by project and program schedules and project or program scope changes. In addition, unplanned dismantling of assets is sometimes required. For example, in fiscal 2018, BC Hydro decommissioned the Salmon River Diversion, which was originally planned to be upgraded, resulting in unplanned dismantling expenditures as discussed on page 7-30, lines 12 to 20 of Chapter 7 of the Application.

BC Hydro's approach to forecasting dismantling costs is informed by historical actuals, but takes into account various considerations outlined below and therefore a direct calculation based on historical actuals cannot be provided. This aggregation of forecasts allows us to form an overall budget for dismantling for the enterprise.

Please refer to Table 7-5 of Chapter 7 of the Application which provides the actual dismantling costs from fiscal 2012 through fiscal 2018. The table below provides the actual dismantling costs for fiscal 2016 through fiscal 2019, broken down by the dismantling categories discussed in the remainder of this response. Prior to fiscal 2016, dismantling costs were not reported by these categories.

($ million)	F2016 Actual	F2017 Actual	F2018 Actual	F2019 Actual
Power System	22.5	40.9	65.7	41.3
Properties	1.2	1.3	1.7	0.5
Technology	0.5	0.2	0.1	0.2
Total	**24.2**	**42.4**	**67.5**	**42.0**

Additional information on the forecasting of dismantling is provided below.

A. Power System:

The power system dismantling forecast for fiscal 2020 and fiscal 2021 comprised of active and planned projects forecasts using the following three considerations:

1. **Recurring Work Programs and Small Capital Projects – associated dismantling is forecast as a percentage of future capital expenditures. The percentage is generally informed by the historical ratio of dismantling expenditures to capital expenditures and varies by different categories of investments (e.g., wood pole, system improvement new feeders, etc.);**
2. **Large Capital Projects – dismantling associated with continuing capital projects is forecast as part of the total project forecast and a provision is used for future planned capital projects aligned with historic levels; and**
3. **Dismantling Projects – dismantling expenditures for continuing dismantling projects (i.e., dismantling work started in a prior fiscal year) are forecast based on the work to date and expected future work. Forecasts for future planned dismantling projects are established based on recently completed dismantling projects of similar size and complexity.**

B. Technology:

Planned Technology dismantling costs are estimated based on actual dismantling costs incurred in previous years and the estimates from active capital projects.

C. Properties:

The costs for the actual demolition of a building or portion of a building is based on tender costs for completing the work or if not available, is based on the actual costs of demolitions for similar sized and constructed buildings. Dismantling costs are forecast based on the expected time of the demolition. The expected demolition is usually linked with the construction or renovation to an existing facility that is included in the Capital Plan.

Forecast Mass Asset Losses
($ million)

Asset Class	Asset Class Description	F2020 Forecast	F2021 Forecast
C11901	Surfacing, Yard	0.2	0.3
C12002	Road, Paved / Gravel	0.2	0.2
C12005	Roads & Trails, Composite Pool	0.2	0.2
C12401	Drainage System, Yard	0.1	0.1
C25101	Structure, Support, Steel	0.2	0.2
C25201	Pole Structures < 60Kv	5.9	6.3
C25202	Pole Structures > 60Kv	0.4	0.5
C25203	Tower, Lattice / Asthetic	1.3	1.2
C25301	Foundations	0.8	0.8
C25401	Ducts & Trenches	0.1	0.1
C25501	Ductbanks < 60Kv	1.7	1.8
C42501	Piping, Water Cooling System	0.1	0.1
C52201	Transformer, Distribution	6.6	6.9
C52202	Distribution, cutouts	1.1	1.2
C55101	Conductor, Overhead > 60 Kv	1.1	1.4
C55102	Conductor, Overhead < 60 Kv	5.4	5.4
C55201	Oh Conductor Services < 60 Kv	1.2	1.3
C55202	Ug Conductor Services < 60 Kv	0.1	0.1
C55301	Cable, Underground < 60 Kv	4.0	4.3
C55304	Cable, Submarine < 60 Kv	0.1	0.1
C55401	Buswork & Station Conductor	0.8	0.9
C55501	Grounding Systems	0.1	0.1
C56001	Insulators	0.5	0.6
C57001	Arrestor, Surge	0.2	0.2
C59401	Meters, Billing, Distribution	0.1	0.1
C59501	Street Lights,Dist. , Owned	0.3	1.0
C61001	Fencing	0.1	0.1
C61101	Alarm/Security System	0.5	0.5
C62001	Fire Protection System	0.4	0.4
C65001	Panels/Cubicles, P & C	1.5	1.7
C68202	Terminal Unit,Remote (Slave)	-	0.1
C68801	Fibre Optic System	0.1	-
C82550	Tools/Work Equipment, Misc	0.2	0.2
C85001	Office Furniture	0.3	0.3
Grand Total		**35.9**	**38.7**

46.0 Powerex

Reference: Exhibit B-6, Attachment 1 to BC Hydro Response to AMPC IR 1.17.3.2, pdf p. 201

On pdf p. 201, when asked to provide a breakdown of gross revenue and related costs associated with Powerex Net Income, BC Hydro stated as follows:

> Details of Powerex Corp's past, current and forecast business activities, unless otherwise publicly reported by BC Hydro (as in Section 8.9 of Chapter 8 and Appendix A of the Application) are commercially sensitive and thus confidential. Powerex net income is included in BC Hydro Trade Income to the benefit of BC Hydro ratepayers.

AMPC seeks to understand the effects of Powerex activity and income on customer rates. AMPC accordingly seeks to understand the types of <u>costs</u> allocated to Powerex and if possible, the general magnitude.

2.46.1 Please provide an explanation as to the types of costs and magnitude of costs, without providing confidential information, that are assigned against Powerex gross income each year to get to Powerex Net Income. If possible, please provide annual values for actual years 2017 – 2018. If considered confidential, please provide a detailed description of what makes each value confidential.

RESPONSE:

Powerex Corp's net income is included in BC Hydro's Trade Income. The inclusion of Trade Income in BC Hydro's revenue requirements reduces the overall revenue requirements to the benefit of ratepayers. Please refer to BC Hydro's response to AMPC IR 1.11.1 where BC Hydro provides an explanation of Trade Income.

Please refer to BC Hydro's response to AMPC IR 1.17.1, where BC Hydro explains that surplus sales are Powerex Corp's purchases from BC Hydro which are costs included in Powerex Corp's costs at the applicable transfer price. Please also refer to Attachment 1 to BC Hydro's response to CEABC IR 1.6.4, where BC Hydro provides surplus sales for fiscal 2010 to fiscal 2019.

With respect to the other types of costs allocated to Powerex Corp., please see section 8.8 of Chapter 8 of the Application for the allocations of costs to Powerex Corp. related to the Corporate Allocation (elaborated on in section 8.10) and related to Point-to-Point Transmission charges.

Further details on Powerex's Corp's costs, unless otherwise publicly reported by BC Hydro (as shown in Sections 8.8 to 8.10 of Chapter 8 and in Appendix A of the Application), are commercially sensitive and therefore confidential. As a result of competition in the market, disclosure of this information would harm Powerex's ongoing and future business interests and its ability to maximize its net income.

46.0 Powerex

Reference: Exhibit B-6, Attachment 1 to BC Hydro Response to AMPC IR 1.17.3.2, pdf p. 201

On pdf p. 201, when asked to provide a breakdown of gross revenue and related costs associated with Powerex Net Income, BC Hydro stated as follows:

> Details of Powerex Corp's past, current and forecast business activities, unless otherwise publicly reported by BC Hydro (as in Section 8.9 of Chapter 8 and Appendix A of the Application) are commercially sensitive and thus confidential. Powerex net income is included in BC Hydro Trade Income to the benefit of BC Hydro ratepayers.

AMPC seeks to understand the effects of Powerex activity and income on customer rates. AMPC accordingly seeks to understand the types of <u>costs</u> allocated to Powerex and if possible, the general magnitude.

2.46.2 Are there government fees, taxes or payments of any kind to government that are included in Powerex related annual costs, and netted against Powerex gross income? If so, please explain each individual charge and how they are calculated to Powerex (i.e. as a component on total energy sales, etc.).

RESPONSE:

Yes, Powerex Corp.'s costs includes payments made to the Province of British Columbia related to the Canadian Entitlement pursuant to the "Entitlement Assignment Agreement". The price for the entitlement volumes received by Powerex Corp. is based on a calculation of a monthly average from the daily on-peak Mid-C prices with some adjustments, elements of which are confidential.

Additionally, as a corporation, Powerex Corp. pays applicable indirect taxes to the Province such as payroll taxes (e.g., CPP, EI, Employer Health Tax), PST, Carbon Tax, and Motor Fuel Tax pursuant to the relevant provincial laws and regulations.

46.0 Powerex

Reference: Exhibit B-6, Attachment 1 to BC Hydro Response to AMPC IR 1.17.3.2, pdf p. 201

On pdf p. 201, when asked to provide a breakdown of gross revenue and related costs associated with Powerex Net Income, BC Hydro stated as follows:

> Details of Powerex Corp's past, current and forecast business activities, unless otherwise publicly reported by BC Hydro (as in Section 8.9 of Chapter 8 and Appendix A of the Application) are commercially sensitive and thus confidential. Powerex net income is included in BC Hydro Trade Income to the benefit of BC Hydro ratepayers.

AMPC seeks to understand the effects of Powerex activity and income on customer rates. AMPC accordingly seeks to understand the types of costs allocated to Powerex and if possible, the general magnitude.

2.46.3 How is the rate that Powerex pays BC Hydro for the cost of BC electricity that Powerex wheels into US markets determined?

RESPONSE:

The price that Powerex pays BC Hydro for electricity purchased by Powerex for export from B.C. is based on the Transfer Pricing Agreement as set out in Appendix A, paragraph 2.1 of that Agreement. A copy of the Agreement is Attachment 1 to this response.

Under the Transfer Pricing Agreement, Powerex pays BC Hydro a defined Transfer Price, which is based on the applicable HLH or LLH Mid-C daily index price adjusted for wheeling costs and transmission losses.

CONFORMED COPY

THIS IS A CONFORMED COPY OF THE TRANSFER PRICING AGREEMENT SHOWING ALL AMENDMENTS IN EFFECT AS OF MARCH 9, 2015. AMENDMENTS ARE SHOWN AS CHANGES TO THE ORIGINAL AGREEMENT BY BLACKLINING. AMENDMENTS WILL CEASE TO HAVE ANY FURTHER FORCE AND EFFECT AND THE TRANSFER PRICING AGREEMENT WILL CONTINUE UNAMENDED UPON THE EXPIRY OR TERMINATION OF THE CAPACITY AND ENERGY PURCHASE AND SALE AGREEMENT BETWEEN FORTISBC AND POWEREX MADE AS OF THE 17th of FEBRUARY, 2015.

TRANSFER PRICING AGREEMENT FOR ELECTRICITY AND GAS

This Agreement is dated as of April 1, 2003 and entered into:

BETWEEN:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, a corporation continued under the Hydro and Power Authority Act

("B.C. Hydro")

AND:

POWEREX CORP., a company duly incorporated under the laws of the Province of British Columbia

("Powerex")

WHEREAS:

A. B.C. Hydro carries on electrical utility operations in the Province of British Columbia and operates the B.C. Hydro System to ensure sufficient energy and capacity is available to meet B.C. Hydro's domestic load and to minimize the cost of serving domestic load and maximize the value of the capability of the B.C. Hydro System to facilitate electricity trading by Powerex in markets outside of British Columbia;

B. Powerex is engaged in the sale and purchase of electricity and natural gas, principally with customers and suppliers in other Canadian provinces and the United States and purchases transmission and transportation capacity in order to support electricity and gas transactions, respectively;

C. The parties wish to confirm the exclusive relationship between B.C. Hydro and Powerex under which Powerex will purchase from B.C. Hydro electricity that is surplus to B.C. Hydro's requirements for domestic load and to confirm the manner in which the parties will otherwise purchase and sell electricity to each other to maximize the value of the B.C. Hydro System;

D. B.C. Hydro is a significant purchaser of natural gas and wishes to enter into an exclusive relationship with Powerex under which B.C. Hydro will purchase its requirements for natural gas from Powerex and sell to Powerex its surplus natural gas; and

E. Both B.C. Hydro and Powerex wish to set out their respective obligations in connection with the foregoing,

NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements contained herein, the parties hereto represent, warrant, covenant, and agree as follows:

1. DEFINITIONS

1.1. Definitions

In this Agreement:

1.1.1. "Additional Daily Quantity" has the meaning set forth in Section 10.3;

1.1.2. "Agreement" means this transfer pricing agreement, together with any Appendices, as amended from time to time;

1.1.3. "B.C. Hydro System" means the reservoirs and all generating resources and related facilities that are controlled by B.C. Hydro, and includes present and future contracted long-term supply from independent power producers or others;

1.1.4. "Burrard Thermal" means the gas-fired generating plant owned by B.C. Hydro and located in Port Moody, British Columbia;

1.1.5. "Domestic Gas Requirements" means the quantity of Gas required by B.C. Hydro for its Thermal Generation Plants to serve Domestic Load and to satisfy its obligations under the Gas Utility Contracts;

1.1.6. "Domestic Load" means:

1.1.6.1. load that B.C. Hydro is obligated to serve under its electricity tariffs by reason of its status as a public utility; and

1.1.6.2. load considered by B.C. Hydro to have equivalent priority of service as load referred to in Section 1.1.6.1 by reason of contract or treaty obligations;

1.1.7. "Electricity Transfer Price" means the applicable price (in US$/MWh) set forth in Appendix A for electricity sold or purchased or deemed to be sold or purchased between B.C. Hydro and Powerex in any hour during the Term of this Agreement, pursuant to any of Sections 5.1, 5.2, 5.3, 6.1 and 6.2;

1.1.8. "FBC Export Capability" means in any hour the amount of FBC Scheduled Capacity (as defined in the FortisBC/Powerex Agreement) (in MW) that FortisBC Inc. makes available to Powerex, to the extent it is scheduled by Powerex to B.C. Hydro;

1.1.9. "FBC Import Capability" means in any hour the estimated amount of electricity (in MWh) that FortisBC Inc. would have been entitled to import into its system to serve its load, after accounting for actual imports and purchases under Rate Schedule 3808;

1.1.10. "FBC Purchase Account" means the account to which electricity recorded as a sale to Powerex that is debited from the Trade Account pursuant to Section 6.4.1 is debited and to which electricity recorded as a sale by Powerex that is credited to the Trade Account pursuant to Section 6.4.2 is credited; for greater certainty, the FBC Purchase Account is a sub-account of the Trade Account and therefore any debit from, or credit to, the FBC Purchase

Account will have a corresponding debit from, or credit to, the Trade Account;

1.1.11. ~~1.1.8.~~ "Force Majeure" means any prevention, delay, stoppage or interruption in the performance of any obligation of a party due to a strike, lockout, labour dispute, act of God, inability to obtain labour or materials, laws, ordinances, rules, regulations or orders of governmental authorities, enemy or hostile action, civil commotion, fire or other casualty, and any condition or cause beyond the reasonable control of the party obligated to perform, but does not include (i) any condition or cause which is the result of the negligence of the claiming party, and which by the exercise of due diligence, the claiming party is unable to avoid, cause to be avoided, or overcome (ii) lack of finances, (iii) any inability of the claiming party to use or resell the electricity or Gas purchased hereunder, or (iv) the loss or failure of the claiming party's supply of electricity or Gas, if the claming party is the seller;

1.1.12. "FortisBC/Powerex Agreement" means the Capacity and Energy Purchase and Sale Agreement made as of the 17th day of February, 2015 between FortisBC Inc. and Powerex providing for the sale by FortisBC Inc. to Powerex of certain Available WAX Capacity (as defined therein), and the sale by Powerex to FortisBC Inc. of energy required by FortisBC Inc. to serve its load, as may be amended from time to time;

1.1.13. ~~1.1.9.~~ "Fort Nelson" means the gas-fired generating plant owned by B.C. Hydro and located in Fort Nelson, British Columbia;

1.1.14. ~~1.1.10.~~ "Gas" means natural gas;

1.1.15. ~~1.1.11.~~ "Gas Delivery Point" means:

1.1.15.1. ~~1.1.11.1.~~ for Gas purchased for use at a Thermal Generation Plant, the recognized custody transfer point between the applicable Thermal Generation Plant and the gas pipeline that serves it; and

1.1.15.2.~~1.1.11.2.~~ for Gas purchased for the purpose of serving the Gas Utility Contracts, the delivery point(s) specified in the Gas Utility Contracts;

1.1.16. ~~1.1.12.~~ "Gas Losses" means for each day, all lost and unaccounted for Gas and Gas burned to fuel compressors, from the applicable Source Point to the applicable Gas Delivery Point;

1.1.17. ~~1.1.13.~~ "Gas Transfer Price" means the price determined in accordance with Appendix B;

1.1.18. ~~1.1.14.~~ "Gas Utility Contracts" means the agreement dated March 7, 2001 between B.C. Hydro and Centra Gas British Columbia Inc. and the agreement dated as of November 27, 1998 between B.C. Hydro and BC Gas Utility Ltd.;

1.1.19. ~~1.1.15.~~ "ICG" means the gas-fired generating plant located at Elk Falls, British Columbia;

1.1.20. ~~1.1.16.~~ "Imbalance Charges" means any fees, penalties, costs or charges (in cash or in kind) assessed by the applicable transportation provider(s) in respect of the Transportation Capacity, for failure to satisfy the transportation balance and nomination requirements;

1.1.21. ~~1.1.17.~~ "Interutility Agreements" means agreements between B.C. Hydro and third parties related to the coordination of reservoir operations, and agreements between B.C. Hydro and one or more control area operators for the purpose of maintaining transmission and generation system reliability and establishing operating procedures, but excludes agreements whose purpose is the purchase and sale of transmission, capacity or energy for profit;

1.1.22. ~~1.1.18.~~ "Net Delivered Quantity to B.C. Hydro" means for any hour, the amount (in MWh) by which the quantity of electricity referred to in Section 3.1.1 exceeds the quantity of electricity referred to in Section 3.1.2;

1.1.23. ~~1.1.19.~~ "Net Delivered Quantity to Powerex " means for any hour, the amount (in MWh) by which the quantity of electricity referred to in Section 3.1.2 exceeds the quantity of electricity referred to in Section 3.1.1;

1.1.24. ~~1.1.20.~~ "Prime Rate" means the annual rate of interest published by B.C. Hydro's principal banker from time to time as its prime rate;

1.1.25. ~~1.1.21.~~ "RPG" means the gas-fired generating plant owned by B.C. Hydro and located in Prince Rupert, British Columbia;

1.1.26. ~~1.1.22.~~ "Source Point" has the meaning set forth in Section 10.7;

1.1.27. ~~1.1.23.~~ "Specified Contract Quantity" has the meaning set forth in Section 10.2;

1.1.28. ~~1.1.24.~~ "Surplus Hydro Electricity" means hydroelectric energy in excess of Domestic Load requirements, that is generated for the purpose of reducing the probability of spill at system reservoirs;

1.1.29. ~~1.1.25.~~ "Surplus System Capability" means at any time, the measure of the B.C. Hydro System's capability, while all Domestic Load requirements are being satisfied, to decrease generation in order to allow purchases of electricity to satisfy Domestic Load and/or to increase generation to allow additional sales, as determined by B.C. Hydro;

1.1.30. ~~1.1.26.~~ "Thermal Generation Plants" means the gas-fired generation plants owned or under the control of B.C. Hydro including, without limitation, Burrard Thermal, Fort Nelson, ICG and RPG;

1.1.31. ~~1.1.27.~~ "Threshold Purchase Price" means the maximum Electricity Transfer Price at which B.C. Hydro will purchase electricity from Powerex in any period to serve Domestic Load, as established by B.C. Hydro from time to time;

1.1.32. ~~1.1.28.~~ "Threshold Sale Price" means the minimum Electricity Transfer Price at which B.C. Hydro will sell Surplus Hydro Electricity to Powerex, as established by B.C. Hydro from time to time;

1.1.33. ~~1.1.29.~~ "Trade Account" means the account to which electricity sold or deemed to be sold by Powerex to B.C. Hydro pursuant to Section 6.1 and 6.4.1 is credited and to which electricity sold or deemed to be sold by B.C. Hydro to Powerex pursuant to Sections ~~6.2~~6.2, 6.4.2 and ~~6.4~~6.6 is debited;

1.1.34. ~~1.1.30.~~ "Transfer Pricing Principle" means the pricing principles established by Sections 12.1 and 12.2;

1.1.35. ~~1.1.31.~~ "Transmission System" means the bulk transmission system owned by B.C. Hydro;

1.1.36. ~~1.1.32.~~ "Transportation Capacity" has the meaning set forth in Section 10.7;

1.1.37. ~~1.1.33.~~ "Variable Operating Costs" means all incremental costs incurred by B.C. Hydro in respect of increasing or reducing generation at the Thermal Generation Plants at the request of Powerex pursuant to Section 7.1 or 7.2, as determined in good faith from time to time by B.C. Hydro; and

1.1.38. ~~1.1.34.~~ "Variable Transportation Costs" means all incremental transportation costs incurred by B.C. Hydro in respect of the use of the Transportation Capacity by Powerex for the purposes of trade.

1.2. **Other Defined Terms**

Capitalized words or phrases appearing in this Agreement that are defined in the Appendices to this Agreement shall have the meanings ascribed to them in the Appendices.

1.3. **Interpretation**

Unless otherwise specified, all references to Sections and Appendices are to those set forth in this Agreement. Reference to any party includes any permitted successor or assignee. The term "including" followed by descriptive words is used in this Agreement by way of example only and is not intended to limit the scope of the provision. The headings used in this Agreement are for convenience and reference purposes only.

2. **TERM**

2.1. **Term**

The effective date of this Agreement is April 1, 2003, notwithstanding the actual date of execution. This Agreement shall continue in full force and effect until terminated by at least 12 months' written notice provided by one party to the other or otherwise upon mutual agreement of the parties.

3. **ACCOUNTING FOR ELECTRICITY DELIVERED**

3.1. **Accounting for Electricity Delivered**

The parties shall for each hour determine the quantity (in MWh) of:

3.1.1. all electricity actually delivered by Powerex to B.C. Hydro under the terms of this Agreement within the hour, including without limitation, electricity purchased by Powerex from independent power producers in British Columbia and sold to B.C. Hydro, plus electricity recorded as a debit to the Trade Account pursuant to Section 6.4.1, but excluding electricity delivered pursuant to Section 7.1; and

3.1.2. all electricity actually delivered by B.C. Hydro to Powerex under the terms of this Agreement within the hour, plus electricity recorded as a credit to the Trade Account pursuant to Section 6.4.2, but excluding electricity delivered pursuant to Section 7.2.

For greater certainty, electricity purchased by Powerex in the U.S. for and on behalf of B.C. Hydro and delivered to the City of Seattle to fulfil B.C. Hydro's obligations under agreements entered into pursuant to the Skagit River Valley Treaty is not included in the quantity of electricity calculated pursuant to Section 3.1.1.

3.2. **Allocation of Net Delivered Quantity to B.C. Hydro and Net Delivered Quantity to Powerex**

The parties shall for each hour, allocate:

3.2.1. any Net Delivered Quantity to Powerex as a sale under either:

3.2.1.1. Section 5.1 in the case where the Electricity Transfer Price was equal to or greater than the Threshold Sale Price for that hour, subject to any maximum quantity specified by B.C. Hydro pursuant to Section 5.1, or

3.2.1.2. Section 6.2, in all other cases; and

3.2.2. any Net Delivered Quantity to B.C. Hydro as a purchase under either:

3.2.2.1. Section 5.2 in the case where the Electricity Transfer Price was equal to or less than the Threshold Purchase Price for that hour, subject to any maximum quantity specified by B.C. Hydro pursuant to Section 5.2, or

3.2.2.2. Section 6.1, in all other cases.

4. **SURPLUS SYSTEM CAPABILITY**

4.1. **Surplus System Capability**

Except as provided by Interutility Agreements, B.C. Hydro shall make the Surplus System Capability exclusively available to Powerex. B.C. Hydro shall purchase electricity from Powerex only to enable it to economically serve Domestic Load and as otherwise contemplated by this Agreement and shall sell all Surplus Hydro Electricity exclusively to Powerex.

5. **PURCHASE AND SALE OF ELECTRICITY - DOMESTIC**

5.1. **Sale and Purchase of Surplus Hydro Electricity**

From time to time, when Surplus Hydro Electricity is available, B.C. Hydro may notify Powerex of the Threshold Sale Price and any maximum quantity of Surplus Hydro Electricity available for sale. If B.C. Hydro does not set a Threshold Sale Price at any time, it will be deemed to not have Surplus Hydro Electricity available for sale. If B.C. Hydro sets a Threshold Sale Price but no maximum quantity of Surplus Hydro Electricity available for sale, then all quantities of electricity available for sale to Powerex by B.C. Hydro shall be subject to this Section 5.1 until different instructions are provided by B.C. Hydro to Powerex. Subject to system constraints, B.C. Hydro shall deliver and Powerex shall use commercially reasonable efforts to schedule and receive Surplus Hydro Electricity at any time when the Electricity Transfer Price is expected by Powerex to be equal to or greater than the Threshold Sale Price, subject to any maximum quantity specified by B.C. Hydro. B.C. Hydro shall sell to Powerex and Powerex shall purchase from B.C. Hydro any Net Delivered Quantity to Powerex allocated as a sale under this Section 5.1 pursuant to Section 3.2.1.

5.2. **Purchase and Sale of B.C. Hydro's Requirements**

Except as provided by Interutility Agreements, B.C. Hydro shall purchase exclusively from Powerex all electricity required by B.C. Hydro to serve Domestic Load that is not supplied from the B.C. Hydro System. From time to time, B.C. Hydro may notify Powerex of the Threshold Purchase Price and any maximum quantity of electricity B.C. Hydro wishes to purchase. If B.C. Hydro does not set a Threshold Purchase Price at any time, it will be deemed to not require electricity from Powerex for the purpose of serving Domestic Load. If B.C. Hydro sets a Threshold Purchase Price but no maximum quantity, then all quantities of electricity available for sale by Powerex to B.C. Hydro shall be subject to this Section 5.2 until different instructions are provided by B.C. Hydro to Powerex. Subject to system constraints, B.C. Hydro shall receive electricity from Powerex and Powerex shall use commercially reasonable efforts to make electricity available to B.C. Hydro at any time when the Electricity Transfer Price is expected by Powerex to be equal to or less than the

Threshold Purchase Price, subject to any maximum quantity requested by B.C. Hydro. B.C. Hydro shall purchase from Powerex and Powerex shall sell to B.C. Hydro any Net Delivered Quantity to B.C. Hydro allocated as a purchase under this Section 5.2 pursuant to Section 3.2.2.

5.3. **Purchases in U.S. to Satisfy B.C. Hydro's Skagit Treaty Obligations**

For each MWh that Powerex delivers to the City of Seattle on behalf of B.C. Hydro to fulfil B.C. Hydro's obligations under agreements entered into pursuant to the Skagit River Valley Treaty from purchases by Powerex in the U.S., B.C. Hydro will pay to Powerex an amount equal to the Electricity Transfer Price in accordance with Section 8.1.3.

6. **PURCHASE AND SALE OF ELECTRICITY - ELECTRICITY TRADE**

6.1. **Sale to B.C. Hydro**

Subject to Section 6.3, at any time when the Electricity Transfer Price is expected by Powerex to be greater than the Threshold Purchase Price or when B.C. Hydro does not require electricity from Powerex to serve Domestic Load, Powerex may schedule and deliver electricity for sale to B.C. Hydro. B.C. Hydro shall purchase from Powerex and Powerex shall sell to B.C. Hydro any Net Delivered Quantity to B.C. Hydro allocated as a purchase under this Section 6.1 pursuant to Section 3.2.2. Such purchases and sales shall be recorded by the parties in the Trade Account as a credit for Powerex's benefit in terms of both quantity of electricity (in MWh) and monetary value (in accordance with Section 8.2.1 or 8.2.2, as applicable).

6.2. **Purchase by Powerex**

Subject to Section 6.3, at any time when the Electricity Transfer Price is expected by Powerex to be less than the Threshold Sale Price or when B.C. Hydro does not have Surplus Hydro Electricity for sale, B.C. Hydro shall at Powerex's request schedule and deliver electricity to Powerex. B.C. Hydro shall sell to Powerex and Powerex shall purchase from B.C. Hydro any Net Delivered Quantity to Powerex allocated as a sale under this Section 6.2 pursuant to Section 3.2.1. Such purchases and sales shall be recorded by the parties in the Trade Account as a debit to Powerex in terms of both quantity of electricity (in MWh) and monetary value (in accordance with Section 8.2.1 or 8.2.2, as applicable).

6.3. **Purchases and Sales Subject to System Capability**

The right of Powerex to sell electricity to B.C. Hydro under Section 6.1 and purchase electricity from B.C. Hydro under Section 6.2 shall be subject to:

6.3.1. Surplus System Capability being available; and

6.3.2. the capability of the Transmission System and B.C. Hydro's rights to use the Transmission System.

6.4. **Trade Account Transactions Using FBC Export Capability and FBC Import Capability**

At the request of Powerex, for any hour:

6.4.1. B.C. Hydro shall record a sale of electricity to Powerex from B.C. Hydro as a debit to the Trade Account, up to the amount of the FBC Export Capability in that hour; and

6.4.2. B.C. Hydro shall record a sale of electricity from Powerex to B.C. Hydro as a credit to the Trade Account, up to the amount of the FBC Import Capability in that hour;

regardless of the Threshold Sale Price, Threshold Purchase Price or the Electricity Transfer Price for that hour. Such sales shall be recorded by the parties (i) in the Trade Account as a debit or credit to Powerex in terms of both quantity of electricity (in MWh) and monetary value (in accordance with Section 8.2.1 or 8.2.2, as applicable), and (ii) in the FBC Purchase Account as a corresponding debit or credit in terms of quantity of electricity (in MWh).

6.5. **FBC Purchase Account Limits**

Powerex shall maintain the FBC Purchase Account to between zero and 30 GW.h (or such other amount as the parties may agree from time to time), and shall reduce the FBC

Purchase Account to zero at end of day on July 31 of each year. Any such reduction will reduce the Trade Account by a corresponding amount.

6.6. ~~6.4.~~ **Sale to B.C. Hydro when Spill Conditions probable**

B.C. Hydro will from time to time provide Powerex with a forecast of the maximum positive balance in the Trade Account (in GW.h) for future months that the B.C. Hydro System can reliably carry. B.C. Hydro may from time to time, revise the forecast as required, provided that such revisions will not reduce the maximum positive balance in the Trade Account by more than 200 GW.h in any period of 30 consecutive days and provided further that B.C. Hydro may not revise its forecast at any time during reservoir spill conditions. If Powerex sells electricity to B.C. Hydro pursuant to Section 6.1 at any time resulting in the positive balance in the Trade Account exceeding the forecast maximum positive balance, then the excess electricity will be recorded in the Trade Account as Excess Electricity for so long as the Trade Account balance exceeds the maximum positive balance. If spill conditions actually occur, B.C. Hydro may by notice to Powerex require Powerex to schedule and receive electricity up to the quantity of Excess Electricity. If B.C. Hydro is unable to deliver the electricity due to (i) system constraints, (ii) Powerex's inability to receive the electricity, or (iii) unavailability of the Transmission System, and B.C. Hydro actually spills water over its dams without generating electricity, B.C. Hydro will be deemed to have sold to Powerex the lesser of (A) the quantity (in MWh) of electricity actually spilled, and (B) the quantity (in MWh) of electricity not delivered, up to the quantity of Excess Electricity recorded in the Trade Account and the Trade Account will be debited in accordance with Section 8.2.1 or 8.2.2, as applicable.

6.7. ~~6.5.~~ **Purchases by B.C. Hydro when Negative Balance in Trade Account**

If and to the extent that there is a negative balance in the Trade Account (in MWh), Powerex shall sell electricity to B.C. Hydro pursuant to Section 6.1 to eliminate or reduce the negative balance as may be required to maintain the B.C. Hydro System within its physical constraints, as determined by B.C. Hydro in its sole discretion.

6.8. ~~6.6.~~ **Alteration of Maintenance Schedules**

B.C. Hydro will use commercially reasonable efforts to schedule the maintenance of the B.C. Hydro System in as an efficient manner as possible to optimize the capability of the B.C. Hydro System to facilitate electricity trading by Powerex in markets outside of British Columbia. Powerex may from time to time request that B.C. Hydro alter the maintenance schedules for any of B.C. Hydro's generators or request alteration of maintenance schedules of the Transmission System for the purpose of accommodating transactions contemplated by Section 6.1 or 6.2. B.C. Hydro may, in its sole discretion, agree to accommodate Powerex's requests. If B.C. Hydro alters maintenance schedules in response to a Powerex request, Powerex shall reimburse B.C. Hydro for incremental costs associated with the alteration of such maintenance schedules.

7. **GAS-FIRED GENERATION PLANTS**

7.1. **Purchase by Powerex from B.C. Hydro's Gas-Fired Generation Plants**

At any time when electricity generated by any of the Thermal Generation Plants is not required to serve Domestic Load, B.C. Hydro may at the request of Powerex, but in its sole discretion, operate such Thermal Generation Plants to generate electricity, subject to Powerex supplying, at its own cost, all Gas required to generate the requested electricity and paying to B.C. Hydro the Variable Operating Costs to generate the requested electricity. The quantity of electricity generated at Powerex's request at the applicable Thermal Generation Plant from the Gas supplied by Powerex pursuant to this Section 7.1 shall be calculated based on the heat rate applicable to generating the requested electricity, taking into account any payment or benefit received by B.C. Hydro from the owner or operator of the Thermal Generation Plant as a result of Powerex's use of the Thermal Generation Plant, which quantity of electricity shall be deemed to be purchased by B.C. Hydro from Powerex pursuant to Section 6.1 regardless of the Threshold Purchase Price or the Electricity Transfer Price at the time. Such sales shall be recorded by the parties in the Trade Account as a credit for Powerex's benefit in terms of both quantity of electricity (in MWh) and monetary value (in accordance with Section 8.2.1 or 8.2.2, as applicable).

7.2. **Displacement of Generation at Powerex's Request**

B.C. Hydro may at the request of Powerex, but in its sole discretion, displace generation of electricity at any Thermal Generation Plant, which electricity would otherwise serve Domestic Load, by electricity delivered from the Trade Account and subject to Powerex paying to B.C. Hydro the Variable Operating Costs attributable to such displacement. The parties acknowledge and agree that the quantity of Gas to be delivered by Powerex pursuant to Section 10.1 for the applicable Thermal Generation Plant shall be reduced accordingly during the period of displacement, provided that B.C. Hydro shall nevertheless be required to pay Powerex for the entire quantity of Gas that was to be purchased, absent such displacement. The quantity of electricity delivered from the Trade Account to displace electricity generated at the applicable Thermal Generation Plant shall be deemed to be sold by B.C. Hydro to Powerex pursuant to Section 6.2 regardless of the Threshold Sale Price or the Electricity Transfer Price at the time. Such transactions shall be recorded by the parties in the Trade Account as a debit to Powerex in terms of both quantity of electricity (in MWh) and monetary value (in accordance with Section 8.2.1 or 8.2.2, as applicable).

8. **PAYMENTS FOR ELECTRICITY TRANSACTIONS**

8.1. **Payments for Electricity Transactions**

The parties acknowledge and agree that:

8.1.1. Powerex shall pay to B.C. Hydro the amount obtained by multiplying each MWh of Surplus Hydro Electricity sold by B.C. Hydro to Powerex under Section 5.1 by the Electricity Transfer Price applicable thereto;

8.1.2. B.C. Hydro shall pay to Powerex the amount obtained by multiplying each MWh of electricity sold by Powerex to B.C. Hydro under Section 5.2 by the Electricity Transfer Price applicable thereto; and

8.1.3. B.C. Hydro shall pay to Powerex the amount obtained by multiplying each MWh of electricity delivered by Powerex to the City of Seattle on behalf of B.C. Hydro to fulfil B.C. Hydro's obligations under agreements entered into pursuant to the Skagit River Valley Treaty, from purchases by Powerex in the U.S., by the Electricity Transfer Price applicable thereto.

8.2. **Adjustments to the Trade Account Balance**

The parties acknowledge and agree that:

8.2.1. if at the beginning of a calendar month, the opening balance of the Trade Account (in MWh) is zero or a positive amount, then:

8.2.1.1. the monetary value credited to the Trade Account for each MWh of electricity sold or deemed to be sold by Powerex to B.C. Hydro under ~~Section~~Sections 6.1 and 6.4.2 during that calendar month, shall be the amount obtained by multiplying each such MWh of electricity sold or deemed to be sold by the Electricity Transfer Price applicable thereto; and

8.2.1.2. the monetary value debited to the Trade Account for each MWh of electricity sold or deemed to be sold by B.C. Hydro to Powerex under Sections ~~6.2~~6.2, 6.4.1 and ~~6.4~~6.6 during that calendar month, shall be the amount obtained by multiplying each such MWh of electricity sold or deemed to be sold by the following amount (in US$/MWh):

8.2.1.2.1. the sum of the monetary value of (a) the Trade Account at the beginning of the calendar month, and (b) all electricity credited to the Trade Account during that calendar month in accordance with Section 8.2.1.1; divided by

8.2.1.2.2. the sum of the number of MWh (a) in the Trade Account at the beginning of the calendar month, and (b) credited to the Trade Account during that calendar month, unless and until the balance in the Trade Account during that calendar month becomes negative, in which case, the monetary value debited to the Trade Account for each MWh of electricity thereafter sold or deemed to be sold by B.C. Hydro to Powerex under Sections ~~6.2~~6.2, 6.4.1 and ~~6.4~~6.6 during that calendar month, shall be the amount obtained by multiplying each such MWh of electricity sold or deemed to be sold by the Electricity Transfer Price applicable thereto,

all calculated and determined at the end of each calendar month; and

8.2.2. if at the beginning of a calendar month, the opening balance of the Trade Account (in MWh) is a negative amount, then:

8.2.2.1. the monetary value debited to the Trade Account for each MWh of electricity sold or deemed to be sold by B.C. Hydro to Powerex under Sections ~~6.2~~6.2, 6.4.1 and ~~6.4~~6.6 during that calendar month, shall be the amount obtained by multiplying each such MWh of electricity sold or deemed to be sold by the Electricity Transfer Price applicable thereto; and

8.2.2.2. the monetary value credited to the Trade Account for each MWh of electricity sold or deemed to be sold by Powerex to B.C. Hydro under ~~Section~~Sections 6.1 and 6.4.2 during that calendar month, shall be the amount obtained by multiplying each such MWh of electricity sold or deemed to be sold by the following amount (in US$/MWh):

8.2.2.2.1. the sum of the monetary value of (a) the Trade Account at the beginning of the calendar month, and (b) all electricity debited to the Trade Account during that calendar month in accordance with Section 8.2.2.1; divided by

8.2.2.2.2. the sum of the number of MWh (a) in the Trade Account at the beginning of the calendar month, and (b) debited to the Trade Account during that calendar month,

unless and until the balance in the Trade Account during that calendar month becomes zero or a positive amount, in which case, the monetary value credited to the Trade Account for each MWh of electricity thereafter sold or deemed to be sold by Powerex to B.C. Hydro under ~~Section~~Sections 6.1 and 6.4.2 during that calendar month, shall be the amount obtained by multiplying each such MWh of electricity sold or deemed to be sold by the Electricity Transfer Price applicable thereto,

all calculated and determined at the end of each calendar month.

9. DELIVERY POINT, TRANSMISSION CHARGES, ANCILLARY SERVICES, SCHEDULING

9.1. Delivery Point, Title and Risk

Unless the parties agree otherwise:

9.1.1. subject to Section 9.1.3, electricity sold by B.C. Hydro to Powerex under Sections 5.1 and 6.2 and electricity purchased by B.C. Hydro from Powerex under Sections 5.2 and 6.1 shall be made available, and title and risk of loss shall pass from the seller to the buyer, at either the British Columbia--United States border or the British Columbia--Alberta border, as determined by Powerex;

9.1.2. electricity delivered by Powerex to B.C. Hydro under Section 7.1 shall be made available and title and risk of loss shall pass from Powerex to B.C. Hydro at the point of interconnection between the applicable Thermal Generation Plant and the Transmission System; and

9.1.3. electricity purchased by Powerex from independent power producers in British Columbia and sold to B.C. Hydro under Section 5.2 or 6.1 shall be made available and title and risk of loss shall pass from Powerex to B.C. Hydro at the point of interconnection between the third party and the Transmission System.

9.2. **Transmission Charges and Ancillary Services**

B.C. Hydro shall pay for all transmission charges and shall self-supply all losses and ancillary services charges, on the Transmission System for electricity transactions under this Agreement. Unless otherwise determined by B.C. Hydro, acting reasonably, Powerex will pay to B.C. Hydro an amount equal to the parties' reasonable estimate of:

9.2.1. the point-to-point transmission costs incurred by B.C. Hydro presently under Rate Schedule 3000 and 3001 in respect of transactions under this Agreement other than sales by B.C. Hydro to Powerex of Surplus Hydro Electricity under Section 5.1, excluding

9.2.2. the point-to-point transmission costs incurred by B.C. Hydro in respect of transactions under any Interutility Agreements, to fulfill any of B.C. Hydro's treaty obligations and transactions in respect of the Canadian Entitlement,

in accordance with Section 15. Such amount is the parties' reasonable allocation of the point-to-point transmission costs incurred by B.C. Hydro in respect of Powerex's trading activities other than in respect of the Canadian Entitlement.

9.3. **Scheduling**

All electricity delivered by Powerex to B.C. Hydro or by B.C. Hydro to Powerex under this Agreement shall be delivered in accordance with standard scheduling practices applicable to the Transmission System.

10. GAS MARKETING

10.1. Purchase and Sale of B.C. Hydro's Gas Requirements

Powerex shall use commercially reasonable efforts to make available to B.C. Hydro, and B.C. Hydro shall purchase exclusively from Powerex B.C. Hydro's Domestic Gas Requirements. B.C. Hydro shall purchase from Powerex and Powerex shall sell to B.C. Hydro all Gas requested by B.C. Hydro under this Agreement from time to time.

10.2. Notification of Monthly Requirements

B.C. Hydro will notify Powerex by the 15th day of each month during the Term (or if that day is not a business day, then the next ensuing business day), of its Domestic Gas Requirements (in GJ/day) for each day of the next following month (or months), specifying the quantity of Gas (in GJ/day) required for each Thermal Generation Plant and for the Gas Utility Contracts (in each case, the "Specified Contract Quantity"). B.C. Hydro agrees to purchase the Specified Contract Quantity from Powerex.

10.3. Notification of Daily Requirements

B.C. Hydro may notify Powerex at any time during a month, of the Domestic Gas Requirements (in GJ/day) in addition to the Specified Contract Quantity, that it projects will be required during any remaining day in the month specified by B.C. Hydro. B.C. Hydro's notice shall specify the quantity of Gas (in GJ/day) required for each Thermal Generation Plant and for the Gas Utility Contracts (in each case, the "Additional Daily Quantity"). B.C. Hydro agrees to purchase the Additional Daily Quantity from Powerex.

10.4. Market Indices

B.C. Hydro may in a notice contemplated by Section 10.2 specify which of the Monthly Index Prices are to be used for the purposes of determining the Gas Transfer Price applicable for such transactions. Such determination shall be for pricing purposes only and shall in no way determine the source from which Powerex is to purchase the Gas to be sold by Powerex to B.C. Hydro hereunder. Powerex shall use commercially reasonable efforts to purchase Gas for delivery to B.C. Hydro under this Agreement at the most favourable

Monthly Index Price (if B.C. Hydro does not specify any such Monthly Index Price) or Daily Index Price, as the case may be, taking into account transportation costs and availability.

10.5. **Payments for Domestic Gas Requirements**

B.C. Hydro shall pay to Powerex the amount obtained by multiplying the applicable Gas Transfer Price by:

10.5.1. the Specified Contract Quantity actually delivered by Powerex to B.C. Hydro each day (in GJ) in accordance with this Agreement plus all Gas Losses applicable to such quantities of Gas actually delivered; and

10.5.2. the Additional Daily Quantity actually delivered by Powerex to B.C. Hydro each day (in GJ) in accordance with this Agreement plus all Gas Losses applicable to such quantities of Gas actually delivered.

All quantities of Gas delivered during any day by Powerex to B.C. Hydro under the terms of this Agreement shall be deemed for the purpose of this Agreement to be delivered firstly on account of the Specified Contract Quantity up to the Specified Contract Quantity, and thereafter on account of the Daily Additional Quantity.

10.6. **Title and Risk**

Possession to, title to and all risk of loss respecting the Gas delivered under this Agreement shall pass from Powerex to B.C. Hydro, at the applicable Gas Delivery Point.

10.7. **Gas Transportation and Storage**

B.C. Hydro shall be responsible for obtaining all third-party Gas transportation and storage capacity required to deliver B.C. Hydro's Domestic Gas Requirements from the point of purchase of the Gas by Powerex from third parties (the "Source Point") to the applicable Gas Delivery Point (such transportation and storage capacity referred to herein as the "Transportation Capacity"). All costs and expenses of transporting and delivering the Gas to the Source Point shall be borne by Powerex and all costs and expenses of transporting the Gas beyond the Source Point shall be borne by B.C. Hydro, including without limitation, all reservation, demand and other charges. Powerex will assist B.C. Hydro, as and when requested by B.C. Hydro and at B.C. Hydro's cost and expense, to obtain the Transportation Capacity. B.C. Hydro hereby grants to Powerex the exclusive right and authority to use any of the Transportation Capacity and B.C. Hydro shall take all necessary steps to enable Powerex to fully use and nominate such Transportation Capacity for Powerex's own account, when not required to deliver B.C. Hydro's Domestic Gas Requirements. Powerex shall pay to B.C. Hydro the Variable Transportation Costs, if applicable, for such use by Powerex of the Transportation Capacity. Powerex shall be responsible for arranging all third-party Gas transportation required to sell Gas that is surplus to B.C. Hydro's Domestic Gas Requirements.

10.8. **B.C. Hydro's Failure to Receive Gas**

If B.C. Hydro fails to receive all or part of the Specified Contract Quantity or Additional Daily Quantity, unless excused by Powerex's failure to perform, then:

10.8.1. B.C. Hydro will pay to Powerex an amount for each GJ of such Gas not received by B.C. Hydro, equal to the positive difference, if any, obtained by subtracting the Sales Price from the applicable Gas Transfer Price; or

10.8.2. Powerex will pay to B.C. Hydro an amount for each GJ of such Gas not received by B.C. Hydro, equal to the positive difference, if any, obtained by subtracting the applicable Gas Transfer Price from the Sales Price,

where "Sales Price" for the purpose of this Section 10.8, means the Daily Index Price contemplated by Section 1.1.3(b) of Appendix B (or otherwise as specified in any amendment thereto).

10.9. **Gas Imbalance Inventory**

B.C. Hydro acknowledges and agrees that all Gas imbalance inventories in the Transportation Capacity recorded with the applicable transportation providers, shall belong to Powerex, to use as it may determine in its sole discretion. If and to the extent that any Thermal Generation Plant consumes in any day, more Gas than has been requested by

B.C. Hydro, and such excess quantity of Gas is delivered to the Gas Delivery Point from the Gas imbalance inventories of Powerex on an unscheduled basis, B.C. Hydro shall pay to Powerex the Daily Index Price (which Daily Index shall be determined by Powerex in its sole discretion) for such excess quantity of Gas. Otherwise, Gas scheduled and delivered by Powerex to B.C. Hydro from the Gas Imbalance Inventories shall be priced in accordance with Section 10.4.

10.10. **Imbalance Charges**

The parties shall use commercially reasonable efforts to avoid imposition of any Imbalance Charges. If Imbalance Charges are incurred as a result of B.C. Hydro's actions or inactions (which shall include, but shall not be limited to, B.C. Hydro's failure to accept quantities of Gas equal to the quantities requested by B.C. Hydro), then B.C. Hydro shall pay such Imbalance Charges, or reimburse Powerex for such Imbalance Charges paid by Powerex to the applicable transportation provider. If the Imbalance Charges were incurred as a result of Powerex's actions or inactions (which shall include, but shall not be limited to, Powerex's failure to deliver quantities of Gas equal to the quantities requested by B.C. Hydro), then Powerex shall pay for such Imbalance Charges or reimburse B.C. Hydro for such Imbalance Charges paid by B.C. Hydro to the applicable transportation provider.

10.11. **Taxes**

B.C. Hydro shall pay or reimburse Powerex for all sales, motor fuel, transfer and other taxes incurred by Powerex in connection with the purchase of Gas by Powerex from third parties for sale to B.C. Hydro under the terms of this Agreement or otherwise applicable to the purchase of Gas by B.C. Hydro from Powerex under the terms of this Agreement.

11. **FORWARD PURCHASES AND SALES FOR B.C. HYDRO**

11.1. **Forward Purchases and Sales for B.C. Hydro**

B.C. Hydro and Powerex may from time to time enter into forward fixed-price, fixed-volume contracts for the purpose of managing market risk associated with purchases of electricity or Gas to meet Domestic Load, or sales of Surplus Hydro Electricity. Such forward contracts will be executed at agreed-upon prices based on prevailing market conditions and will be financially-settled against an agreed-upon market index. B.C. Hydro and Powerex may agree to wholly or partially close any resulting forward position by entering into an offsetting forward contract at an agreed-upon fixed price based on then prevailing market conditions.

12. TRANSFER PRICING PRINCIPLES

12.1. Electricity Transfer Pricing Principle

The parties acknowledge and agree that all electricity sold and purchased or deemed to be sold and purchased between B.C. Hydro and Powerex pursuant to Sections 5 and 6 of this Agreement are deemed for transfer pricing purposes to occur at the British Columbia-United States border. B.C. Hydro and Powerex declare that the Electricity Transfer Price is intended to be established as a sale price that reflects the fair market value of electricity delivered at the British Columbia-United States border during heavy load hours in a day or light load hours in a day, whichever is applicable, at which parties acting on an arms-length basis would be willing to transact.

12.2. Gas Transfer Pricing Principle

The parties acknowledge and agree that all Gas sold to B.C. Hydro by Powerex pursuant to Section 10 of this Agreement is deemed for transfer pricing purposes to occur at the Source Point corresponding to the applicable index price specified by B.C. Hydro or determined by Powerex in accordance with Section 10.4. B.C. Hydro and Powerex declare that the Gas Transfer Price is intended to be established as a sale price that reflects the fair market value of Gas delivered at such applicable Source Point on a monthly or daily basis, as applicable, at which parties acting on an arms-length basis would be willing to transact.

12.3. Electricity Transfer Price and Gas Transfer Price

The parties agree that the initial pricing methodology for determining the Electricity Transfer Price is as set forth in Appendix A and the Gas Transfer Price is as set forth in Appendix B.

12.4. **Pricing Methodology**

B.C. Hydro and Powerex acknowledge that from time to time during the term of this Agreement different methods for determining the Electricity Transfer Price or Gas Transfer Price, as the case may be, may be appropriate to meet the applicable Transfer Pricing Principle. No earlier than April 1, 2004 or 12 months since the pricing methodology was last established, if a party believes that the then current pricing methodology for determining the Electricity Transfer Price or the Gas Transfer Price, as the case may be, (including any values established under it) would produce a price that does not meet the Transfer Pricing Principle during the next 12 months, the party may, by notice to the other party, seek to renegotiate the then current pricing methodology. The parties shall negotiate in good faith to establish, within 90 days of such notice, a new pricing methodology for determining the Electricity Transfer Price or the Gas Transfer Price, as the case may be, to replace the then current methodology. If the parties are unable to negotiate a new pricing methodology for determining the Electricity Transfer Price or the Gas Transfer Price, as the case may be, within such time, either party may submit the matter to dispute resolution pursuant to Section 19. Upon agreement or determination of the new pricing methodology by dispute resolution, the new pricing methodology shall become effective at the beginning of the month immediately following the 90th day after the initial notice and the parties shall adjust amounts paid from that date. In no event shall the parties adjust the amounts paid or payable for any period prior to the effective date of the new pricing methodology.

13. **INFORMATION AND FORECASTS**

13.1. **Information and Forecasts**

The parties shall provide information to each other on system and market conditions, including, without limitation, the forecasts (and revisions thereof) to be provided by B.C. Hydro to Powerex pursuant to Sections ~~6.4~~6.6 and 13.2; provided, however that the foregoing and any information sharing with respect to the transmission capabilities of the B.C. Hydro System shall be done only within the information sharing limits set forth in the Standards of Conduct for Grid Operations and InterUtility Affairs or successor policies of

B.C. Hydro published from time to time by B.C. Hydro and the information sharing limits imposed by pertinent Canadian and United States regulatory authorities.

13.2. **Gas Information and Forecasts**

B.C. Hydro shall provide to Powerex, in accordance with North American industry standards, ongoing forecasts regarding B.C. Hydro's surplus Gas position, demand for Gas and the status of physical storage and delivery for B.C. Hydro's Gas, and shall coordinate and cooperate with Powerex regarding the same; provided, however that the foregoing shall be done only within the information sharing limits imposed by pertinent Canadian and United States regulatory authorities.

14. **CONFIDENTIAL INFORMATION**

14.1. **Powerex Information Is Confidential**

B.C. Hydro acknowledges that Powerex operates in a highly competitive market and that disclosure of information relating to Powerex, its business and operations could be reasonably expected to significantly harm the competitive position of Powerex or interfere with the negotiating position of Powerex with trading counterparties. Accordingly, information provided by Powerex at the request of B.C. Hydro, including information in connection with B.C. Hydro's audit from time to time, is proprietary and is provided only on condition that it shall be kept confidential by B.C. Hydro and not disclosed to any third party.

14.2. **B.C. Hydro Information Is Confidential**

Powerex acknowledges that disclosure of information relating to B.C. Hydro, its business and operations could be reasonably expected to significantly harm the competitive position of B.C. Hydro. Accordingly, information provided by B.C. Hydro at the request of Powerex is proprietary and is provided only on condition that it shall be kept confidential by Powerex and not disclosed to any third party.

15. **BILLING; PAYMENTS.**

15.1. **Powerex to Provide Statement for Electricity and Gas Transactions**

Powerex shall send to B.C. Hydro for each calendar month statements setting forth:

15.1.1. the total electricity that was delivered during that month, and

15.1.2. the total Gas that was delivered during that month,

in each case with sufficient detail to enable the parties to determine the amount received and the payments due in connection therewith. Statements shall be sent within 10 days of the end of the month.

15.2. **B.C. Hydro to Provide Statement**

B.C. Hydro shall send to Powerex for each calendar month statements setting forth the amount owing by Powerex to B.C. Hydro or by B.C. Hydro to Powerex pursuant to Sections ~~6.6.~~6.8, 7.1 (Variable Operating Costs), 7.2 (Variable Operating Costs), 9.2 and 10.7 (Variable Transportation Costs) for that month, with sufficient detail to enable the parties to determine the payment due in connection therewith. Statements shall be sent within 10 days of the end of the month.

15.3. **Netting and Payment**

The amounts that each party owes to the other for electricity and Gas under this Agreement for each month shall be aggregated and the party, if any, owing the greater aggregate amount shall pay to the other party the difference between the amounts owed. Unless otherwise agreed between the parties, payments shall be due on or before the 25th day of the month, or if such day is not a business day, the immediately following business day, and shall be made by wire transfer or other agreed manner. Unless otherwise agreed between the parties, overdue payments shall accrue interest from, and including, the due date to, but excluding, the date of payment at the Prime Rate plus 2%. US dollars shall be converted to Canadian dollars using the Bank of Montreal, Toronto, monthly average noon-rate of the month during which the payment obligations were incurred.

15.4. **Dispute of Invoices**

Each party shall have the right to dispute any amount which is set out in any statement or invoice in accordance with the procedure set out in Section 19. All statement and invoice amounts shall be paid pending resolution of any dispute.

16. **REPRESENTATIVES OF THE PARTIES**

16.1. **Designated Representatives**

B.C. Hydro and Powerex may from time to time designate representatives for the purpose of giving or confirming any approval required pursuant to this Agreement. As of the date hereof, the representative of B.C. Hydro shall be its President or delegate, and the representative of Powerex shall be its President or delegate.

17. **FORCE MAJEURE**

17.1. **Suspension for Force Majeure**

If either party is or was wholly or partly unable because of a Force Majeure, to perform an obligation arising from this Agreement and claims that a Force Majeure is occurring or has occurred and reasonably establishes that fact, then the performance of the obligation shall be deemed to be suspended provided always that:

17.1.1. the suspension shall be of no greater scope and no longer duration than the Force Majeure,

17.1.2. the non-performing party shall make its best efforts to counter the Force Majeure or to otherwise remedy its inability to perform the obligation,

17.1.3. a performance required at a time other than when the Force Majeure is occurring shall not be excused by the Force Majeure,

17.1.4. an obligation to pay any fees when due shall not be excused by the Force Majeure; however, to the extent that there are any savings to either party as a result of the Force Majeure, that party shall pass on any savings to the other party so as to reduce its obligation accordingly.

18. **INDEMNITY AND CONSEQUENTIAL DAMAGES**

18.1. **Indemnity**

Each party shall indemnify the other party and its employees, agents and subcontractors from and against any and all claims, demands, losses, costs, damages, actions, suits or other proceedings made, sustained, brought or prosecuted which such other party may incur, suffer or be put to arising out of, or in any way based upon, any act or omission of such other party performing its obligations under this Agreement unless such act or omission constitutes gross negligence or wilful misconduct on the part of such other party.

18.2. **Consequential Damages**

In no event shall either party be liable to the other or to any third party for incidental, indirect, special or consequential damages, howsoever caused and on any theory of liability, arising out of or related to the performance of this Agreement.

19. **DISPUTE RESOLUTION**

19.1. **Disputes Defined**

For purposes of this Section 19, "Dispute" means any dispute that arises under or in connection with this Agreement and includes any failure to agree upon the Electricity Transfer Price, the Gas Transfer Price or the amounts contemplated by Section 9.2, from time to time or any of the factors that go into determining such prices.

19.2. **Senior Executives**

The parties shall use reasonable efforts to settle all Disputes. In the event any such Dispute is not settled within 30 days after the date such Dispute arises, each party shall within 10 days refer the matter in dispute to its Chief Executive Officer (the "Senior Executives). The Senior Executives shall meet within 21 days to attempt to negotiate a resolution of the

Dispute. Settlement offers shall not be admissible in any subsequent dispute resolution process.

19.3. **Arbitration**

If the parties have not succeeded in negotiating a resolution of the Dispute within 30 days after the first meeting of the Senior Executives or if the Senior Executives do not meet within 10 days, the parties shall be deemed to be at an impasse and either party may commence arbitration procedures in accordance with this Section. Unless the parties otherwise agree, any arbitration commenced in accordance with this Section 19 shall be determined by a single arbitrator and shall proceed in accordance with the Domestic Commercial Arbitration Rules of Procedure of the British Columbia International Commercial Arbitration Centre, as they may be in force at the time of the arbitration.

19.4. **Sole Means of Resolving Dispute**

The parties declare that arbitration pursuant to this Section 19 shall be the exclusive means of resolving any Dispute and the determination of the arbitrator shall be final and binding. The parties expressly declare that the arbitrator shall have the express authority to determine the Electricity Transfer Price, the Gas Transfer Price or the amounts contemplated by Section 9.2, from time to time in the event of a Dispute.

20. **NOTICES**

20.1. **Notices**

Any notice or other communication provided for herein or given hereunder to a party shall be in writing and shall be delivered by facsimile transmission, or in person to the individual listed below:

20.1.1. to Powerex:

Powerex Corp.
Suite 1400, Park Place
666 Burrard Street
Vancouver, British Columbia
V6C 2X8

Attention: President

20.1.2. to B.C. Hydro:

British Columbia Hydro and Power Authority
333 Dunsmuir Street
Vancouver, British Columbia
V6B 5R3

Attention: President

or such other address with respect to a party as such party shall notify the other in writing as above provided. Notices by facsimile transmission shall be deemed given upon verification of successful transmission and notice in person shall be deemed given upon actual delivery.

21. **MISCELLANEOUS**

21.1. **Waiver by Agreement**

This Agreement and any provision hereof may only be amended, waived, discharged, or terminated by an instrument in writing signed by the party against whom enforcement of the amendment, waiver, discharge, or termination is sought.

21.2. **Non-Waiver**

No waiver or successive waivers by a party of any provision of this Agreement shall operate as a discharge of such covenant, agreement, or condition or render the same invalid or impair the right of one party to enforce the same in the event of any subsequent breach or breaches by the other.

21.3. **Amendments**

If at any time during this Agreement the parties consider it necessary or expedient to make an amendment, supplement, waiver, or other modification to this Agreement they may do so only by means of a written agreement between them.

21.4. **Severability**

If any term, covenant, or condition of this Agreement or application thereof to any person or circumstances shall to any extent be invalid, illegal, or unenforceable in any respect, the remainder of this Agreement or application of such term, covenant, or condition to such person or circumstance other than those as to which it is held invalid, illegal or unenforceable shall not be affected thereby, and each term, covenant, or condition of this Agreement and this Agreement shall be valid and legal and shall be enforced to the fullest extent permitted by law.

21.5. **Complete Agreement**

This Agreement represents the entire agreement of the parties with respect to the subject matter hereof.

21.6. **Other Agreements**

If there is any conflict between the provisions of this Agreement and any other agreement entered into prior to this Agreement, then the provisions of this Agreement shall control.

21.7. **Governing Laws**

This Agreement and the rights and obligations of the parties hereto shall be governed by and be construed in accordance with the laws of the Province of British Columbia.

21.8. **Headings**

The headings in this Agreement have been inserted for reference only and do not define, limit, alter, or enlarge the meaning of any provision of this Agreement.

21.9. **Assignment**

This Agreement may not be assigned, in whole or in part, by Powerex without the prior written consent of B.C. Hydro.

21.10. **Successors And Assigns**

This Agreement is binding upon and shall inure to the benefit of the parties hereto and their respective successors and assigns.

21.11. **Counterparts**

This Agreement may be executed in two or more counterparts, each of which shall be deemed an original but all of which shall constitute but one instrument.

21.12. **Third Party Beneficiaries**

Except as provided expressly by this Agreement, nothing in this Agreement nor its performance shall be relied upon by third parties or create any rights or obligations to third parties.

21.13. **Non Restriction**

Nothing in this Agreement is intended to limit Powerex from conducting transactions outside of this Agreement.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the day and year first above written.

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

By:__________________________________

POWEREX CORP.

By: __________________________________

APPENDIX A

CALCULATION OF ELECTRICITY TRANSFER PRICE

1. **INTERPRETATION**

1.1. **Definitions**

For purposes of this Appendix A the following words and terms shall have the following meanings:

1.1.1. "Agreement" means the transfer pricing agreement to which this Appendix A is attached and of which it forms a part.

1.1.2. "BPA" means Bonneville Power Administration.

1.1.3. "DJMC" means the relevant index published by DowJones for transactions reported at Mid-Columbia.

1.1.4. "Losses" means the BPA average system-wide loss factor (as a percentage) charged under BPA's tariff multiplied by the On-Peak Price or the Off-Peak Price, as the case may be, for the applicable hour, plus any other charges for ancillary services.

1.1.5. "NERC" means the North American Electric Reliability Council or any successor organization

1.1.6. "Off-Peak Hours" means the hours ending 1 through 6 and the hours ending 23 and 24, Monday through Saturday, and hours ending 1 through 24 on Sunday and NERC holidays.

1.1.7. "Off-Peak Price" means, for an Off-Peak Hour:

1.1.7.1. for days other than Sundays and NERC holidays, the DJMC Firm Off-Peak Index price (in US$/MWh) for that hour; or

1.1.7.2. for Sundays and NERC holidays, the DJMC Sunday 24-hour Firm Index price (in US$/MWh) for that hour.

1.1.8. "On-Peak Hours" means the hours ending 7 through 22, Monday through Saturday, excluding NERC holidays.

1.1.9. "On-Peak Price" means, for an On-Peak Hour, the DJMC Firm On-Peak Index price (in US$/MWh) for that hour.

1.1.10. "Transmission Costs" means the rate under the prevailing BPA tariff for hourly non-firm transmission.

1.2. **Interpretation**

In this Appendix A, references to Sections are references to Sections of this Appendix unless otherwise specified.

1.3. **DowJones Telerate Index Price**

For purposes of the calculations in this Appendix A, it is assumed that the Mid-Columbia DowJones telerate index price is determined in the manner specified in the DowJones "Wholesale Electricity Price Indexes - Mid-Columbia (Mid-C definition - A/O 6/1/98, revised 12/31/98 and the Electricity Price Indexes calculations revised 12/31/98). In the event that the index prices referred to in this Appendix A are no longer determined in the manner described in the foregoing publications, then, if the change is material, either party may, by notice to the other party, seek to renegotiate the then current pricing methodology, failing which the matter shall be resolved by dispute resolution in accordance with Section 19 of the Agreement.

2. **ELECTRICITY TRANSFER PRICE**

2.1. **Sales by B.C. Hydro to Powerex**

The Electricity Transfer Price payable by Powerex to B.C. Hydro for electricity sold or deemed to be sold to Powerex under Section 5.1 and 6.2 of the Agreement shall be:

2.1.1. for each On-Peak Hour, the price in (US$/MWh) obtained by subtracting from the On-Peak Price for that hour, the Transmission Costs and Losses applicable to the electricity delivered in that hour; and

2.1.2. for each Off-Peak Hour, the price (in US$/MWh) obtained by subtracting from the Off-Peak Price for that hour, the Transmission Costs and Losses applicable to the electricity delivered in that hour.

2.2. **Purchases by B.C. Hydro from Powerex**

The Electricity Transfer Price payable by B.C. Hydro to Powerex for electricity sold or deemed to be sold to B.C. Hydro under Sections 5.2 and 6.1 of the Agreement shall be:

2.2.1. for each On-Peak Hour, the sum (in US$/MWh) of the On-Peak Price for that hour plus the Transmission Costs and Losses applicable to the electricity delivered in that hour; and

2.2.2. for each Off-Peak Hour, the sum (in US$/MWh) of the Off-Peak Price for that hour plus the Transmission Costs and Losses applicable to the electricity delivered in that hour.

2.3. **US Purchases to Meet B.C. Hydro Obligations**

If and to the extent that Powerex purchases electricity in the U.S. for delivery to fulfil B.C. Hydro's obligations under agreements entered into pursuant to the Skagit River Valley Treaty, the Electricity Transfer Price payable by B.C. Hydro to Powerex for such electricity shall be:

2.3.1. for each On-Peak Hour, the sum (in US$/MWh) of the On-Peak Price for that hour, plus Losses applicable to the electricity delivered in that hour; and

2.3.2. for each Off-Peak Hour, the sum (in US$/MWh) of the Off-Peak Price for that hour, plus Losses applicable to the electricity delivered in that hour.

APPENDIX B

CALCULATION OF GAS TRANSFER PRICE

1. **INTERPRETATION**

1.1. **Definitions**

For purposes of this Appendix B the following words and terms shall have the following meanings:

1.1.1. "Agreement" means the Transfer Pricing Agreement to which this Appendix B is attached and of which it forms a part.

1.1.2. "Bid-Week" means the last 5 business days of each calendar month.

1.1.3. "Daily Index Price" means any one of the following daily index prices applicable to the sale of Gas from Powerex to B.C. Hydro pursuant to this Agreement, as determined by Powerex in accordance with Section 10.4 of the Agreement:

(a) The Midpoint of Westcoast, Station 2 index price set out in Gas Daily, as published by Platts, a division of The McGraw-Hill Companies Inc., being the weighted average of all daily fixed price trades at Station 2 daily, reported by index participants.

(b) The Midpoint of Northwest, Canadian border (Sumas) index price set out in Gas Daily, as published by Platts, a division of The McGraw-Hill Companies Inc., being the weighted average of all daily fixed price trades at Sumas daily, reported by index participants.

(c) The AECO-NIT Daily Spot gas index price set out in the Canadian Gas Price Reporter, as published by Canadian Enerdata Ltd., being the volume-weighted average of all gas trades that occur on the

NGX trading platform for a particular delivery day.

(d) The Midpoint of PG&E-GTNW, Kingsgate index price, set out in Gas Daily as published by Platts, a division of The McGraw-Hill Companies Inc. being the weighted average of all daily fixed trades at Kingsgate daily, reported by index participants.

1.1.4. "Monthly Index Price" means any one of the following monthly index prices applicable to the sale of Gas from Powerex to B.C. Hydro pursuant to this Agreement, as specified by B.C. Hydro or determined by Powerex in accordance with Section 10.4 of the Agreement:

(a) The Station 2 one-month spot gas index price as set out in Canadian Gas Price Reporter, published by Canadian Enerdata Ltd., being the volume-weighted average of all monthly fixed price trades as reported by index participants.

(b) The Northwest Pipeline Corp., Canadian Border Index price as set out in inside FERC's gas market report monthly prices of spot gas delivered to pipelines at Sumas, as published by Platts, a division of the McGraw-Hill Companies Inc., being the weighted average of all monthly fixed price trades reported at Sumas during the Bid-Week prior to the month of delivery.

(c) The AECO-NIT One-Month spot gas index price set out in the Canadian Gas Price Reporter, as published by Canadian Enerdata Ltd., being a volume-weighted average of all gas trades that occur on the NGX trading platform for a particular prompt delivery month.

1.1.5.

1.2. **Interpretation**

In this Appendix B, references to Sections are references to Sections of this Appendix unless otherwise specified.

1.3. **Conversion**

Any references to mmBtu's in any Daily Index Price or Monthly Index Price, shall be converted to GJ on the basis that one mmBtu equals 1.055056 GJ's.

1.4. **Index Prices**

In the event that a Monthly Index Price or Daily Index Price, or any other published index price on which the Gas Transfer Price may be based ceases to exist, or ceases to be representative of the price for daily or monthly, as the case may be, fixed price Gas trades, at the applicable trading hub, or the manner of determining such index price materially changes, then either party may, by notice to the other party, seek to renegotiate the applicability of that Monthly Index Price or Daily Index Price and a suitable replacement therefore. Failing which the matter shall be resolved by dispute resolution in accordance with Section 19 of the Agreement.

1.5. **Gas Transfer Price**

The Gas Transfer Prices payable by B.C. Hydro to Powerex are as follows:

1.5.1. the Monthly Index Price as specified by B.C. Hydro or determined by Powerex in accordance with Section 10.4, for each day in which B.C. Hydro has requested a Specified Contract Quantity for use at a Thermal Generation Plant or for the purpose of serving a Gas Utility Contract, as the case may be; and

1.5.2. the Daily Index Price as specified by B.C. Hydro or determined by Powerex in accordance with Section 10.4, for each day in which B.C. Hydro has requested an Additional Daily Quantity for use at a Thermal Generation Plant or for the purpose of serving a Gas Utility Contract, as the case may be.

46.0 Powerex

Reference: Exhibit B-6, Attachment 1 to BC Hydro Response to AMPC IR 1.17.3.2, pdf p. 201

On pdf p. 201, when asked to provide a breakdown of gross revenue and related costs associated with Powerex Net Income, BC Hydro stated as follows:

> Details of Powerex Corp's past, current and forecast business activities, unless otherwise publicly reported by BC Hydro (as in Section 8.9 of Chapter 8 and Appendix A of the Application) are commercially sensitive and thus confidential. Powerex net income is included in BC Hydro Trade Income to the benefit of BC Hydro ratepayers.

AMPC seeks to understand the effects of Powerex activity and income on customer rates. AMPC accordingly seeks to understand the types of <u>costs</u> allocated to Powerex and if possible, the general magnitude.

2.46.3 How is the rate that Powerex pays BC Hydro for the cost of BC electricity that Powerex wheels into US markets determined?

2.46.3.1 Are any other BC Hydro based costs applied against Powerex's gross income to arrive at its net income?

RESPONSE:

Please refer to BC Hydro's response to AMPC IR 2.46.1 for a discussion of costs allocated to Powerex Corp.

47.0 Regulatory Account Interest

Reference (i): Exhibit B-1, BC Hydro's RRA Application, 7.9.2 Interest Rate Applied to Regulatory Accounts, p. 7-58 and 7-59, pdf p. 949

In its Application at pdf p. 949, BC Hydro states as follows:

> 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.

The table provided on the page prior, 7-58 lists that all Cost of Energy deferral accounts, and most other short-term cash related variance accounts are charged interest in this manner.

Reference (ii): Exhibit B-5, BC Hydro Response to BCUC IR 1.140.7, pdf p. 1629

At pdf p. 1629, BC Hydro provides a table of forecast interest related to each regulatory account and whether or not the interest is recovered in rates during F2020 and F2021:

	$ million	Ref.	Recovered in Test Period	F2020 Forecast	F2021 Forecast
1	Heritage Deferral Account	2.1 L4	Yes	(11)	(4)
2	Non-Heritage Deferral Account	2.1 L11	Yes	3	1
3	Trade Income Deferral Account	2.1 L17	Yes	(1)	(0)
4	Storm Restoration Costs	2.2 L43	Yes	1	0
5	Amortization of Capital Additions	2.2 L56	Yes	1	0
6	Rock Bay Remediation	2.2 L101	Yes	(1)	(0)
7	Arrow Water Systems	2.2 L116	Yes	0	0
8	Remediation	2.2 L130	Yes	(1)	(0)
9	Real Property Sales	2.2 L141	No	2	1
10	Dismantling Cost	2.2 L158	Yes	1	0
11	First Nations Costs	2.2 L11	Yes	3	2
12	Site C	2.2 L23	No	19	19
13	SMI	2.2 L89	Yes	8	7
14	**Total Interest on Regulatory Accounts**	2.1 L25 + 2.2 L205		**24**	**28**

2.47.1 Please explain why BC Hydro is charging interest for accounts capturing timing differences and/or cash related expenses.

RESPONSE:

Interest is applied to certain regulatory accounts as described in section 7.9 of Chapter 7 of the Application. For regulatory accounts related to variances (i.e., Cost of Energy Variance Accounts and Other Cash Variance Accounts), there is a timing difference between when BC Hydro spends money and when that expenditure is recovered from ratepayers. As a result, BC Hydro incurs financing charges to carry amounts that are paid in cash but not recovered in rates in the same test period. Interest is therefore generally applied to these regulatory accounts, and is applied using BC Hydro's weighted average cost of debt, in accordance with BCUC orders. The interest which is charged to the accounts is recovered in future periods from ratepayers, along with the recovery of the underlying expenditure which gave rise to the carrying cost.

In the example described above, finance charges recovered from ratepayers in a given year are reduced by the amount of interest charged to regulatory account. Therefore, ratepayers are not charged twice for interest and pay only actual interest costs.

47.0 Regulatory Account Interest

Reference (i): Exhibit B-1, BC Hydro's RRA Application, 7.9.2 Interest Rate Applied to Regulatory Accounts, p. 7-58 and 7-59, pdf p. 949

In its Application at pdf p. 949, BC Hydro states as follows:

> 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.

The table provided on the page prior, 7-58 lists that all Cost of Energy deferral accounts, and most other short-term cash related variance accounts are charged interest in this manner.

Reference (ii): Exhibit B-5, BC Hydro Response to BCUC IR 1.140.7, pdf p. 1629

At pdf p. 1629, BC Hydro provides a table of forecast interest related to each regulatory account and whether or not the interest is recovered in rates during F2020 and F2021:

	$ million	Ref.	Recovered in Test Period	F2020 Forecast	F2021 Forecast
1	Heritage Deferral Account	2.1 L4	Yes	(11)	(4)
2	Non-Heritage Deferral Account	2.1 L11	Yes	3	1
3	Trade Income Deferral Account	2.1 L17	Yes	(1)	(0)
4	Storm Restoration Costs	2.2 L43	Yes	1	0
5	Amortization of Capital Additions	2.2 L56	Yes	1	0
6	Rock Bay Remediation	2.2 L101	Yes	(1)	(0)
7	Arrow Water Systems	2.2 L116	Yes	0	0
8	Remediation	2.2 L130	Yes	(1)	(0)
9	Real Property Sales	2.2 L141	No	2	1
10	Dismantling Cost	2.2 L158	Yes	1	0
11	First Nations Costs	2.2 L11	Yes	3	2
12	Site C	2.2 L23	No	19	19
13	SMI	2.2 L69	Yes	8	7
14	**Total Interest on Regulatory Accounts**	2.1 L25 + 2.2 L205		**24**	**28**

2.47.2 Please explain why BC Hydro is applying its WACC, largely impacted by long-term (and often higher) interest rates, as opposed to a short-term interest rate, more indicative of the length of time these costs are carried for?

RESPONSE:

BC Hydro notes that the question refers to "WACC", which BC Hydro assumes refers to weighted average cost of capital. BC Hydro applies interest to regulatory accounts based on its weighted average cost of debt (WACD), in accordance with BCUC orders. The remainder of this response is in respect of the WACD.

BC Hydro's WACD is impacted by both long-term interest rates and short-term interest rates. Furthermore, the rate is applied consistently to all regulatory accounts which attract interest, whether there is a longer or shorter recovery period associated with those regulatory accounts. Please refer to BC Hydro's response to AMPC IR 1.4.4, where we explain why it is not reasonable to charge interest on regulatory accounts using BC Hydro's forecast Canadian short-term debt interest rate, of which the associated period is only three months.

BC Hydro manages its debt on a portfolio basis, and we do not specifically allocate finance charges to specific drivers of debt. However, if there were a difference between the actual financing charges BC Hydro incurs to carry amounts deferred to regulatory accounts during the test period and the interest applied to a regulatory account at the WACD rate during that period, there would be no benefit or harm to ratepayers. This is because, as a result of the Total Finance Charges Regulatory Account, ratepayers only pay for BC Hydro's actual finance charges.

48.0 Energy Study & Water Flows

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.1, pdf p. 167

At pdf p. 167, BC Hydro states that:

BC Hydro is unable to provide the revised Energy Studies financial policy as it has not yet been finalized and reviewed by the BC Hydro Board of Directors. BC Hydro expects to have a finalized and reviewed revised Energy Studies financial policy by March 31, 2020.

Reference (ii): Exhibit B-5, BC Hydro Response to BCUC IR 1.31.1, pdf pp. 373-375

At pdf pp. 373-375, BC Hydro provided an explanation about the range of inputs used in the Energy Study, as discussed in Appendix DD of the application, including as follows:

> The use of these weather year ensembles ensures that the variability in inflows, prices, loads, and resources due to the impacts of weather are well represented in the models, producing a range of possible outcomes. This range captures both dry and wet periods and accurately represents the historic geographic correlation in weather between the regions included in the modeling. This range is large enough that BC Hydro considers the average of the resulting forecast to be an unbiased estimator of the drivers, and hence how the system will be operated.
>
> …
>
> As of 2018, historic weather and inflow data exists for the period 1973 through 2017. These 45 years provide the basis for the ensemble set. The Energy Study models require 5 years of inflow data. As a result, a set of parallel sequences is created from the data that preserves any year-over-year correlation, as follows …
>
> …
>
> The 45 possible weather sequences were used as an input into the October 2018 Energy Studies, along with the starting elevation of each reservoir as of October 1, 2018.

AMPC wishes to better understand the range of potential impacts water inflows have on Energy Study results and correspondingly on forecast revenue.

2.48.1 Please confirm AMPC's understanding, based on BC Hydro's response, that BC Hydro routinely uses an unapproved Energy studies financial policy. If not confirmed, please fully explain your response.

RESPONSE:

Not confirmed. AMPC's understanding of BC Hydro's response to AMPC IR 1.15.1 is not correct.

As described in the Energy Studies Process Audit (Appendix DD of the Application, page 10):

Key Conclusions and Findings:

> **"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. The 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."**

Management Action Plans:

> **"Management will review and re-publish the policy by March 31, 2019."**

The current policy and related Monthly Energy Studies Procedure are provided as Attachments 1 and 2 to this response:

- **Attachment 1 – Commodity Risk Management Policy for Short Term Domestic Market Transactions (Revision 6, February 23, 2011); and**
- **Attachment 2 – Monthly Energy Studies Approval Procedure (March 1, 2011)**

The Energy Studies are approved pursuant to the attached policy and procedure. As stated in BC Hydro's response to AMPC IR 1.15.1, BC Hydro expects to have a finalized and reviewed revised Energy Studies Financial Policy by March 31, 2020.

Commodity Risk Management Policy for Short Term Domestic Market Transactions

Issue Date: 15 February 2005

Revision 6 (23 February 2011)

Executive Sponsor
Executive Vice-President Finance and Chief Financial Officer, Charles Reid, 74400

Contact for Policy Interpretation and Clarification
Manager, Business Support Services, Carol Richards, 73614

The Board of Directors delegated overall authority for risk management to the CEO and company Executives, including Director of Dam Safety. Within the context of the Corporate Risk Management Policy, the purpose of this Commodity Risk Management Policy for Short Term Domestic Market Transactions (CRMP) is to reduce the risk associated with the Cost of Short Term Domestic Market Transactions beyond the risk reduction that is provided by BC Hydro system storage optimization and regulatory deferral accounts. The CRMP also provides governance for approvals to changes in the Approved Cost of Domestic Market Transactions.

The Board of Directors sets the risk management framework by approving the hedge limits, products, and counterparties as follows.

Hedge Limits

Month 1 – 12	Month 13 – 24	Month 25 – 36
0-60% of expected Net Domestic Market Transactions	0-50% of expected Net Domestic Market Transactions	0-25% of expected Net Domestic Market Transactions

Approved Products and Counterparties

Category	Products and Limits
Electricity Transactions	<u>Approved Products:</u> Financial Products ▪ Fixed-for-floating swaps ▪ Financially-settled options <u>Counterparty:</u> Powerex under Transfer Pricing Agreement <u>Settlement Location</u>: as agreed under Transfer Pricing Agreement <u>Term</u>: next 36 months <u>Settlement Price:</u> based on Transfer Pricing Agreement

Category	Products and Limits
Natural Gas Transactions	Approved Products: Financial Products ▪ Fixed-for-floating swaps ▪ Financially-settled options Counterparty: ▪ Powerex under Transfer Pricing Agreement Delivery or Settlement Locations: Sumas, AECO, Station 2 Term: next 36 months Settlement Price: based on Transfer Pricing Agreement

The Board of Directors further delegates the authority for managing the commodity risk of Short Term Domestic Market Transactions to senior management as follows:

- The CFO is responsible for ensuring that the procedures developed and implemented in association with the CRMP are in compliance with BC Hydro Corporate Policies.
- The Generation Executive Vice-President (EVP Generation) is responsible for ensuring that appropriate risk management techniques and control procedures are established to fulfil the purpose of the CRMP.
- The Manager, Business Support Services is responsible for ensuring compliance with specific internal control or financial functions within the CRMP related procedures, consistent with the frameworks established by the Corporate Financial Responsibility and Risk Management Policies.

Your Role in Fulfilling This Policy

Employees are responsible for managing risk in a responsible and triple bottom line accountable manner, within the guidelines set by the company, by understanding and applying the approved risk management policies and procedures. Employees are responsible for applying risk management in a manner that balances risk reduction value with cost of such risk reduction, and for addressing risks that they are or become aware of.

Policy Application

Generation is responsible for managing the cost and risk associated with BC Hydro's short term domestic obligations by prudently planning and executing the operation of the BC Hydro system, domestic market purchases and sales of electricity and gas, and coordinating with Powerex, as governed by the Transfer Pricing Agreement, to maximize the value of any excess system capability through trade within the context of triple bottom line objectives. Domestic Market Transactions are driven by long or short energy position, market prices and/or system constraints. On a monthly basis, or more frequently if required, Generation develops an operating plan that seeks to optimize the economic value of system operation, considering both expected values and uncertainties, subject to environmental and social constraints. The operating plan is summarized in the

Monthly Energy Studies Report and the resulting Cost of Domestic Market Transactions for current and subsequent two fiscal years is subject to approval as specified in the Special Authorities Table 3 of the Financial Approval Procedure.

Based on the Monthly Energy Studies, the risk associated with the Cost of Short Term Domestic Market Transactions is further managed by Generation through such risk management techniques as required by this policy and further outlined in the Hedging Procedure. This risk management is incremental, above and beyond the risk reduction provided by system storage optimization and regulatory deferral accounts.

Approval limits over electricity and gas transactions are specified in the Special Authorities Table 3 of the Financial Approval Procedure.

Related Policies

MAPP 1.2.1A - Financial Responsibility
MAPP 1.2.2A - Risk Management

Related Procedures

MAPP 1.2.1B.1 - Financial Approval Procedure
Monthly Energy Studies Approval Procedure
Hedging Procedure

Supporting Documentation

Heritage Contract Accountability Framework
Transfer Pricing Agreement for Electricity and Gas

Definitions

Approved Cost of Domestic Market Transactions: Defined in Financial Approval Procedure

Cost of Domestic Market Transactions: Defined in Financial Approval Procedure

Domestic Market Transactions: Forecast domestic market purchases and sales of gas and electricity.

Heritage Contract Accountability Framework: The Heritage Contract accountability Framework defines the respective roles and responsibilities of Generation and the Deputy CEO for implementing and managing Heritage Contract and Non-Heritage Contract resources to serve domestic load obligations.

Risk: The likelihood and severity of an event or action that will adversely affect BC Hydro's ability to achieve its business objectives and execute its strategies successfully.

Short Term Domestic Market Transactions: Forecasted Domestic Market Transactions within the "operational" timeframe of three years into the future.

Transfer Pricing Agreement for Electricity and Gas: An agreement between BC Hydro and Powerex that describes responsibilities and allocates accountabilities of both Powerex and BC Hydro with respect to system operations and trading decisions.

Monthly Energy Studies Approval Procedure

Revision Date: 1 March 2011

Purpose

To implement the Commodity Risk Management Policy for Short Term Domestic Market Transactions (CRMP) by establishing approval levels and delegative powers for authorizations relating to the Monthly Energy Studies.

Responsible Organization Unit

Generation Resource Management (GRM)

Responsible Manager

Director, Generation Resource Management Renata Kurshner 72624

Procedures

The procedure will be reviewed and, if necessary, updated on an annual basis, or more frequently as circumstances warrant. Changes to this procedure are approved by Executive Vice President, Generation (EVP Generation).

On a monthly basis, or more frequently if required, GRM develops an operating plan that seeks to optimize the economic value of system operation, considering both expected values and uncertainties, subject to environmental and social constraints. The operating plan is summarized in the Monthly Energy Studies Report and provides information on Short Term forecast of system operation, system imports and exports and their allocation, if any, to the Trade Account, Threshold Purchase and/or Threshold Sale Price and resulting Cost of Domestic Market Transactions.

There are infrequent cases where BC Hydro must purchase or sell specific amounts of energy during a time period, due to extreme domestic loads (high or low), transmission constraints, must run generation, imminent reservoir level and other constraints. In such circumstance, GRM will specify "physical" energy quantities it needs to purchase or sell, which will override Trade Account allocation normally based on Threshold Purchase or Sale Price.

Approval Levels

- The Board of Directors has delegated approval to changes in the Approved Cost of Domestic Market Transactions in Special Authorities Table 3 of the Financial Approval Procedure. Table 1 is included in this procedure for reference purposes only and is not intended to override the Financial Approval Procedure.

Table 1 Approval levels to changes in the Approved Cost of Domestic Market Transactions

Authority	Approval Level based on change to Approved Cost of Domestic Market Transactions
CEO/CFO jointly	Change of up to + C $200M (per Financial Approval Procedure)
EVP Generation	Change of up to + C $100M (per Financial Approval Procedure)
Director, GRM	Change of up to + C $25M (per Financial Approval Procedure)

- Changes to the Threshold Purchase Price and Threshold Sale Price for the current and subsequent two fiscal years are within the approval of EVP Generation, who has further delegated the approval limits to management as follows:

Table 2 Approval levels to changes of Threshold Purchase or Sale Price

Authority	Level based on Change in Threshold Price
EVP Generation	Full discretion
Director, GRM	Up to greater of +/- US $ 4 or 10% relative to the Threshold Purchase or Sale Price compared to the previous EVP Generation approval.
Portfolio Manger	Up to greater of +/- US $ 2 or 5% relative to the Threshold Purchase or Sale Price compared to the previous EVP Generation approval.

Reporting Requirements

Regular Reports	Issued by	Frequency	Distribution	Approvals
Monthly Energy Study Package	Portfolio Manager	Monthly	• EVP Generation • Generation Finance Lead • Director, Generation Operations • Powerex • Corporate Finance • Manager, Business Support Services	Threshold Purchase and/or Sale Price for current and following two fiscal years. Cost of Domestic Market Transactions for current and following two fiscal years.
Reports issued as Required	**Issued by**	**Frequency**	**Distribution**	**Approvals**
Policy and/or Procedure Violation Report	Manager, Business Support Services	Upon discovery of Policy and/or Procedure violation	• Director GRM • EVP Generation • Chief Risk Offices • Generation Finance Lead • Corporate Groups Finance Lead • CFO	None

Signed approval of Cost of Domestic Market Transactions and Threshold Purchase and/or Sale Price in the Monthly Energy Study Package shall be delivered to the Manager, Business Support Services prior to 12:00pm on the next business day following the approval. Delay in such delivery, however, will not prevent implementation of the approved Threshold Purchase and/or Sale Price by GRM.

DEFINITION OF TERMS

Approved Cost of Domestic Market Transactions: Defined in Financial Approval Procedure

Cost of Domestic Market Transactions: Defined in Financial Approval Procedure

Domestic Market Transactions: Forecast domestic market purchases and sales of gas and electricity.

Heritage Contract Accountability Framework: The Heritage Contract accountability Framework defines the respective roles and responsibilities of Generation and Customer Care and Conservation for implementing and managing Heritage Contract and Non-Heritage Contract resources to serve domestic load obligations.

Short Term: Operational timeframe of three years into the future.

Trade Account: Defined in Transfer Pricing Agreement as meaning the account to which electricity sold or deemed to be sold by Powerex to BC Hydro is credited and to which electricity sold or deemed to be sold by BC Hydro to Powerex is debited.

Transfer Pricing Agreement for Electricity and Gas: An agreement between BC Hydro and Powerex that describes responsibilities and allocates accountabilities of both Powerex and BC Hydro with respect to system operations and trading decisions.

Threshold Purchase Price: Defined in Transfer Pricing Agreement as meaning the maximum Electricity Transfer Price at which BC Hydro will purchase electricity from Powerex in any period to serve domestic load, as established by BC Hydro from time to time.

Threshold Sale Price: Defined In Transfer Pricing Agreement as meaning the minimum Electricity Transfer Price at which BC Hydro will sell surplus electricity to Powerex, as established by BC Hydro from time to time.

48.0 Energy Study & Water Flows

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.1, pdf p. 167

At pdf p. 167, BC Hydro states that:

BC Hydro is unable to provide the revised Energy Studies financial policy as it has not yet been finalized and reviewed by the BC Hydro Board of Directors. BC Hydro expects to have a finalized and reviewed revised Energy Studies financial policy by March 31, 2020.

Reference (ii): Exhibit B-5, BC Hydro Response to BCUC IR 1.31.1, pdf pp. 373-375

At pdf pp. 373-375, BC Hydro provided an explanation about the range of inputs used in the Energy Study, as discussed in Appendix DD of the application, including as follows:

> The use of these weather year ensembles ensures that the variability in inflows, prices, loads, and resources due to the impacts of weather are well represented in the models, producing a range of possible outcomes. This range captures both dry and wet periods and accurately represents the historic geographic correlation in weather between the regions included in the modeling. This range is large enough that BC Hydro considers the average of the resulting forecast to be an unbiased estimator of the drivers, and hence how the system will be operated.
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> As of 2018, historic weather and inflow data exists for the period 1973 through 2017. These 45 years provide the basis for the ensemble set. The Energy Study models require 5 years of inflow data. As a result, a set of parallel sequences is created from the data that preserves any year-over-year correlation, as follows …
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> The 45 possible weather sequences were used as an input into the October 2018 Energy Studies, along with the starting elevation of each reservoir as of October 1, 2018.

AMPC wishes to better understand the range of potential impacts water inflows have on Energy Study results and correspondingly on forecast revenue.

2.48.2 Please provide the Energy Study Financal policy that BC Hydro used in preparing Energy Study reports and related tasks.

RESPONSE:

Please refer to BC Hydro's response to AMPC IR 2.48.1 for the current Energy Study Financial Policy.

48.0 Energy Study & Water Flows

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.1, pdf p. 167

At pdf p. 167, BC Hydro states that:

BC Hydro is unable to provide the revised Energy Studies financial policy as it has not yet been finalized and reviewed by the BC Hydro Board of Directors. BC Hydro expects to have a finalized and reviewed revised Energy Studies financial policy by March 31, 2020.

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> The use of these weather year ensembles ensures that the variability in inflows, prices, loads, and resources due to the impacts of weather are well represented in the models, producing a range of possible outcomes. This range captures both dry and wet periods and accurately represents the historic geographic correlation in weather between the regions included in the modeling. This range is large enough that BC Hydro considers the average of the resulting forecast to be an unbiased estimator of the drivers, and hence how the system will be operated.
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> The 45 possible weather sequences were used as an input into the October 2018 Energy Studies, along with the starting elevation of each reservoir as of October 1, 2018.

AMPC wishes to better understand the range of potential impacts water inflows have on Energy Study results and correspondingly on forecast revenue.

2.48.3 Please explain qualitatively and directionally what changes were applied to the last approved policy compared to the currently utilized policy.

RESPONSE:

Please refer to BC Hydro's response to AMPC IR 2.48.1 for a discussion of the current Energy Studies Financial Policy. As noted in that response, the last approved policy is the currently utilized policy, and a revised policy is expected to be finalized by March 31, 2020.

48.0 Energy Study & Water Flows

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.1, pdf p. 167

At pdf p. 167, BC Hydro states that:

BC Hydro is unable to provide the revised Energy Studies financial policy as it has not yet been finalized and reviewed by the BC Hydro Board of Directors. BC Hydro expects to have a finalized and reviewed revised Energy Studies financial policy by March 31, 2020.

Reference (ii): Exhibit B-5, BC Hydro Response to BCUC IR 1.31.1, pdf pp. 373-375

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> The use of these weather year ensembles ensures that the variability in inflows, prices, loads, and resources due to the impacts of weather are well represented in the models, producing a range of possible outcomes. This range captures both dry and wet periods and accurately represents the historic geographic correlation in weather between the regions included in the modeling. This range is large enough that BC Hydro considers the average of the resulting forecast to be an unbiased estimator of the drivers, and hence how the system will be operated.
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> The 45 possible weather sequences were used as an input into the October 2018 Energy Studies, along with the starting elevation of each reservoir as of October 1, 2018.

AMPC wishes to better understand the range of potential impacts water inflows have on Energy Study results and correspondingly on forecast revenue.

2.48.4 Does BC Hydro assign a probability of occurrence to water inflow and other Energy Study inputs? If so, please explain how these are incorporated into the Energy Study. If not, please confirm that each year of input data is incorporated with the same probability of occurrence.

RESPONSE:

Each five-year sequence of input data associated with a given weather year is assumed to have the same probability of occurrence.

48.0 Energy Study & Water Flows

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.1, pdf p. 167

At pdf p. 167, BC Hydro states that:

BC Hydro is unable to provide the revised Energy Studies financial policy as it has not yet been finalized and reviewed by the BC Hydro Board of Directors. BC Hydro expects to have a finalized and reviewed revised Energy Studies financial policy by March 31, 2020.

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> The 45 possible weather sequences were used as an input into the October 2018 Energy Studies, along with the starting elevation of each reservoir as of October 1, 2018.

AMPC wishes to better understand the range of potential impacts water inflows have on Energy Study results and correspondingly on forecast revenue.

2.48.5 Please explain why the five-year ensemble sets of January 1973 to December 1977, January 1974 to December 1978, January 2014 to December 1973, and January 2017 and December 1976 were chosen.

RESPONSE:

BC Hydro uses the five-year ensemble sets because the Energy Study models the dispatch of the system five fiscal years into the future. Financial forecasts are derived from the results for the first three fiscal years. Running the model for the additional two years allows the forecast for the first three years to account for the impact of longer term operational constraints (e.g., scheduled outages in the fourth and fifth years).

The 1973 start date was chosen for the Energy Studies because as of that year both the G.M. Shrum and Mica generating stations were in-service, and as a result consistently calculated historic inflow data is available starting in 1973. Please refer to BC Hydro's response to AMPC IR 2.48.6 for the start and end dates that were used for the 45 ensemble sets.

48.0 Energy Study & Water Flows

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.1, pdf p. 167

At pdf p. 167, BC Hydro states that:

BC Hydro is unable to provide the revised Energy Studies financial policy as it has not yet been finalized and reviewed by the BC Hydro Board of Directors. BC Hydro expects to have a finalized and reviewed revised Energy Studies financial policy by March 31, 2020.

Reference (ii): Exhibit B-5, BC Hydro Response to BCUC IR 1.31.1, pdf pp. 373-375

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> The use of these weather year ensembles ensures that the variability in inflows, prices, loads, and resources due to the impacts of weather are well represented in the models, producing a range of possible outcomes. This range captures both dry and wet periods and accurately represents the historic geographic correlation in weather between the regions included in the modeling. This range is large enough that BC Hydro considers the average of the resulting forecast to be an unbiased estimator of the drivers, and hence how the system will be operated.
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> The 45 possible weather sequences were used as an input into the October 2018 Energy Studies, along with the starting elevation of each reservoir as of October 1, 2018.

AMPC wishes to better understand the range of potential impacts water inflows have on Energy Study results and correspondingly on forecast revenue.

2.48.6 Please explain if BC Hydro uses the entire aggregate 45 year historic inflow data or just the weather ensemble sets to forecast possible ranges of inflows. If the former, please explain how these five year data sets to 'preserve any year-over-year correlation' are input into the model along with the 45 year historic inflows. Please explain if the end result is the same year of data being input multiple times within the model or, if not, how the model differentiates these data sets.

RESPONSE:

In the Energy Study, each five-year sequence defines one operating scenario (i.e. possible outcome for five years), where operation is sensitive to not only weather and inflows, but also factors including prices, loads, IPP deliveries, and unit availability. All 45 years of historic weather and inflow data are used to construct the ensemble of five-year forecasts used as input for the Energy Study.

While it is true that the same historic weather data, for example, 1977, is used in 5 out of the 45 sequences, for any one of the five modelled years it is only used once. An example below is provided to further illustrate this point.

	Calendar Year/Weather Sequence				
	Year 1 (2018)	Year 2 (2019)	Year 3 (2020)	Year 4 (2021)	Year 5 (2022)
Scenario 1	1973	1974	1975	1976	1977
Scenario 2	1974	1975	1976	1977	1978
Scenario 3	1975	1976	1977	1978	1979
[…]					
Scenario 45	2017	1973	1974	1975	1976

As a result, each modelled fiscal year (for example fiscal 2019) has 45 possible outcomes that are considered equally likely to occur with each outcome based on one year out of the 45 historical years of data.

Note that the modelled output (generation, imports/exports) for a particular weather year (for example, 1977) will be slightly different in fiscal 2019 in comparison to fiscal 2020 because the initial conditions and some of the other aforementioned factors will also be different.

Year-over-year correlation in the input data is preserved throughout sequences with consecutive weather years, and corresponds physically to conservation of snowpack and groundwater according to historical record.

48.0 Energy Study & Water Flows

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.1, pdf p. 167

At pdf p. 167, BC Hydro states that:

BC Hydro is unable to provide the revised Energy Studies financial policy as it has not yet been finalized and reviewed by the BC Hydro Board of Directors. BC Hydro expects to have a finalized and reviewed revised Energy Studies financial policy by March 31, 2020.

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> The 45 possible weather sequences were used as an input into the October 2018 Energy Studies, along with the starting elevation of each reservoir as of October 1, 2018.

AMPC wishes to better understand the range of potential impacts water inflows have on Energy Study results and correspondingly on forecast revenue.

2.48.7 For the October 2018 Energy Study supporting BC Hydro’s F2020-F2021 RRA, please provide the range of historic weather inflow outcomes used (i.e. the lowest and the highest aggregate inflow levels on record) and provide the revenue and cost implications (including gas purchases and market purchases that may result). Please also include in this table the averaged inflow levels corresponding to each test year (or multi-year period) and the resulting revenue.

RESPONSE:

In the Energy Study, BC Hydro models the following components of the revenues and costs relative to each weather sequence in the ensemble:

- **Revenue from load;**
- **Revenue from market sales;**
- **Market electricity prices;**
- **Cost from market purchases;**
- **Cost from water rentals;**
- **Revenues (costs) from Columbia River Treaty Related Agreements; and**
- **Cost of gas purchases.**

The tables and plots below for fiscal years 2020 and 2021 are from the October 2018 Energy Study and reflect the potential variability in the above components on consolidated net revenue from operations relative to the system inflow as a percent of Normal.

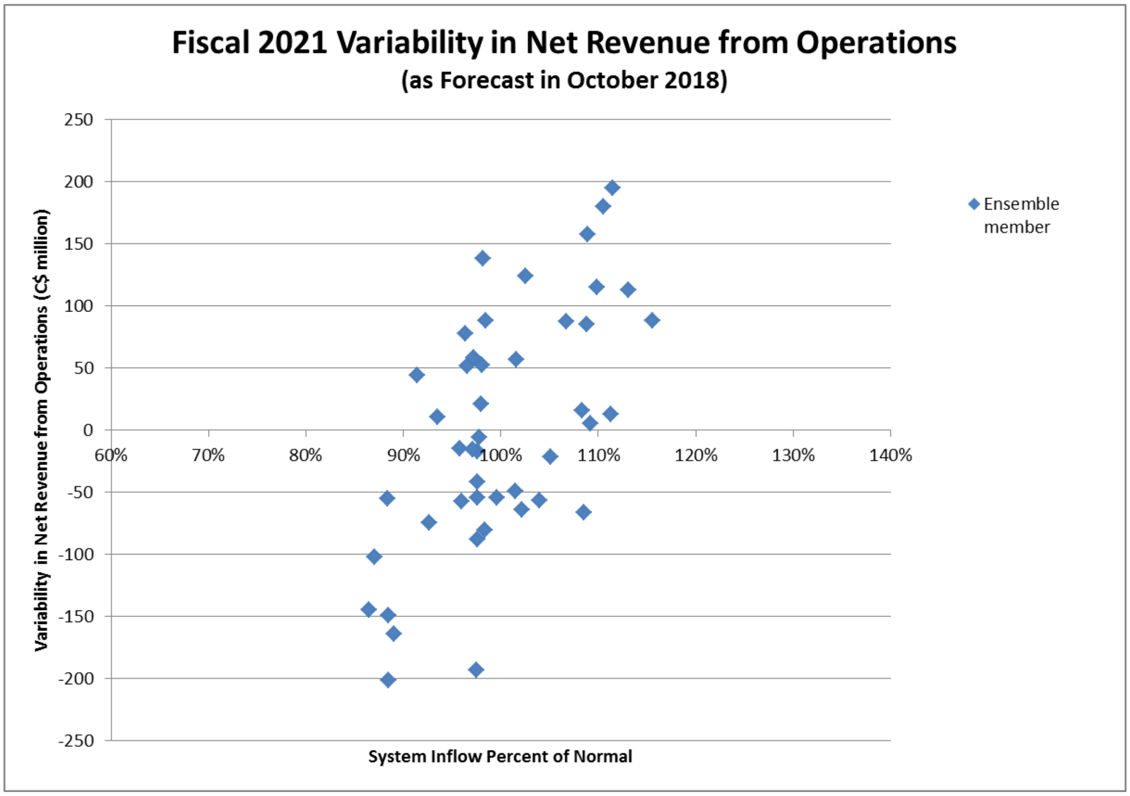
Variability in Value of Net Revenue from Operations
(C$ million)
(mean value set to zero)

Percentile	Min	10	25	75	90	Max
Fiscal 2020	**-177**	**-117**	**-53**	**52**	**120**	**205**
Fiscal 2021	**-201**	**-128**	**-57**	**78**	**120**	**195**

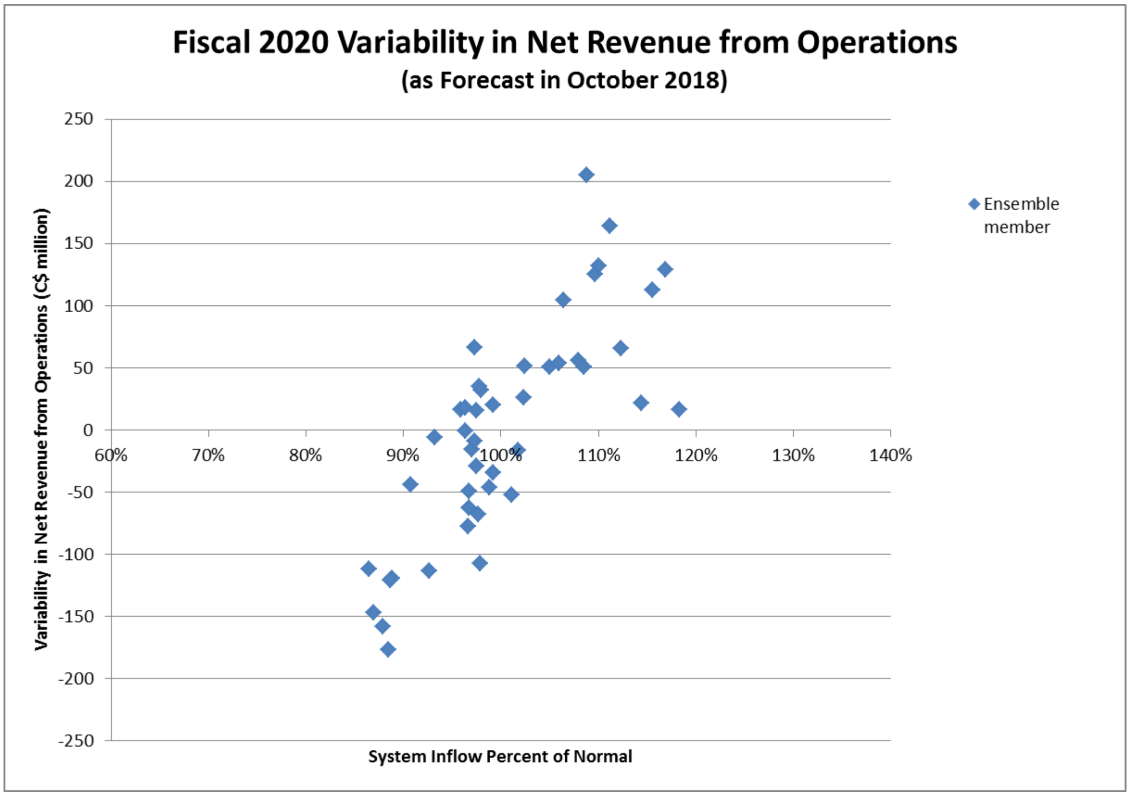
Variability in System Inflow as Percent of Normal

Percentile (%)	Min	10	25	75	90	Max
Fiscal 2020	**86**	**89**	**96**	**106**	**112**	**118**
Fiscal 2021	**86**	**89**	**96**	**107**	**110**	**116**

Weather-driven variability in costs of Energy Purchase Agreements with Independent Power Producers is a significant component of the overall variability in Cost of Energy that is not modelled as part of consolidated net revenue from operations and therefore not captured in the tables and graphs. As can be seen in the graphs, the consolidated net revenue from operations from these components can vary by approximately +/- C$200 million per year. There are other components of Cost of Energy not captured in the tables and graphs which include, for example, domestic transmission costs and costs associated with non-integrated areas, which are included in the Total Cost of Energy on line 65 of schedule 4.0 in Appendix A to the Application.



Fiscal 2021 Variability in Net Revenue from Operations
(as Forecast in October 2018)
Variability in Net Revenue from Operations (C$ million)
250
200
150
100
50
0
-50
-100
-150
-200
-250
60%
70%
80%
90%
100%
110%
120%
130%
140%
System Inflow Percent of Normal
Ensemble member


Fiscal 2020 Variability in Net Revenue from Operations
(as Forecast in October 2018)
Variability in Net Revenue from Operations (C$ million)
250
200
150
100
50
0
-50
-100
-150
-200
-250
60%
70%
80%
90%
100%
110%
120%
130%
140%
System Inflow Percent of Normal
Ensemble member

48.0 Energy Study & Water Flows

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.1, pdf p. 167

At pdf p. 167, BC Hydro states that:

BC Hydro is unable to provide the revised Energy Studies financial policy as it has not yet been finalized and reviewed by the BC Hydro Board of Directors. BC Hydro expects to have a finalized and reviewed revised Energy Studies financial policy by March 31, 2020.

Reference (ii): Exhibit B-5, BC Hydro Response to BCUC IR 1.31.1, pdf pp. 373-375

At pdf pp. 373-375, BC Hydro provided an explanation about the range of inputs used in the Energy Study, as discussed in Appendix DD of the application, including as follows:

> The use of these weather year ensembles ensures that the variability in inflows, prices, loads, and resources due to the impacts of weather are well represented in the models, producing a range of possible outcomes. This range captures both dry and wet periods and accurately represents the historic geographic correlation in weather between the regions included in the modeling. This range is large enough that BC Hydro considers the average of the resulting forecast to be an unbiased estimator of the drivers, and hence how the system will be operated.
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>
> The 45 possible weather sequences were used as an input into the October 2018 Energy Studies, along with the starting elevation of each reservoir as of October 1, 2018.

AMPC wishes to better understand the range of potential impacts water inflows have on Energy Study results and correspondingly on forecast revenue.

2.48.8 Please provide aggregate starting elevation of reservoir levels as of October 1, 2018. Provide a table of monthly averaged and aggregate water inflow results from the Energy Study underpinning the F2020-F2021 RRA.

RESPONSE:

BC Hydro characterizes aggregate inflows as System Inflow Energy and aggregate reservoir elevation as System Storage, both of which are reported in terms of GWh energy content.

We provide tables and graphs illustrating both historic and forecast monthly System Inflow Energy and System Storage from the October 2018 Energy Study in BC Hydro's confidential response to BCUC IR 1.20.2.

The reservoir elevation levels for Kinbasket Reservoir and Williston Reservoir on October 1, 2018 were 745.13 m and 666.58 m, respectively.

48.0 Energy Study & Water Flows

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.1, pdf p. 167

At pdf p. 167, BC Hydro states that:

BC Hydro is unable to provide the revised Energy Studies financial policy as it has not yet been finalized and reviewed by the BC Hydro Board of Directors. BC Hydro expects to have a finalized and reviewed revised Energy Studies financial policy by March 31, 2020.

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> The 45 possible weather sequences were used as an input into the October 2018 Energy Studies, along with the starting elevation of each reservoir as of October 1, 2018.

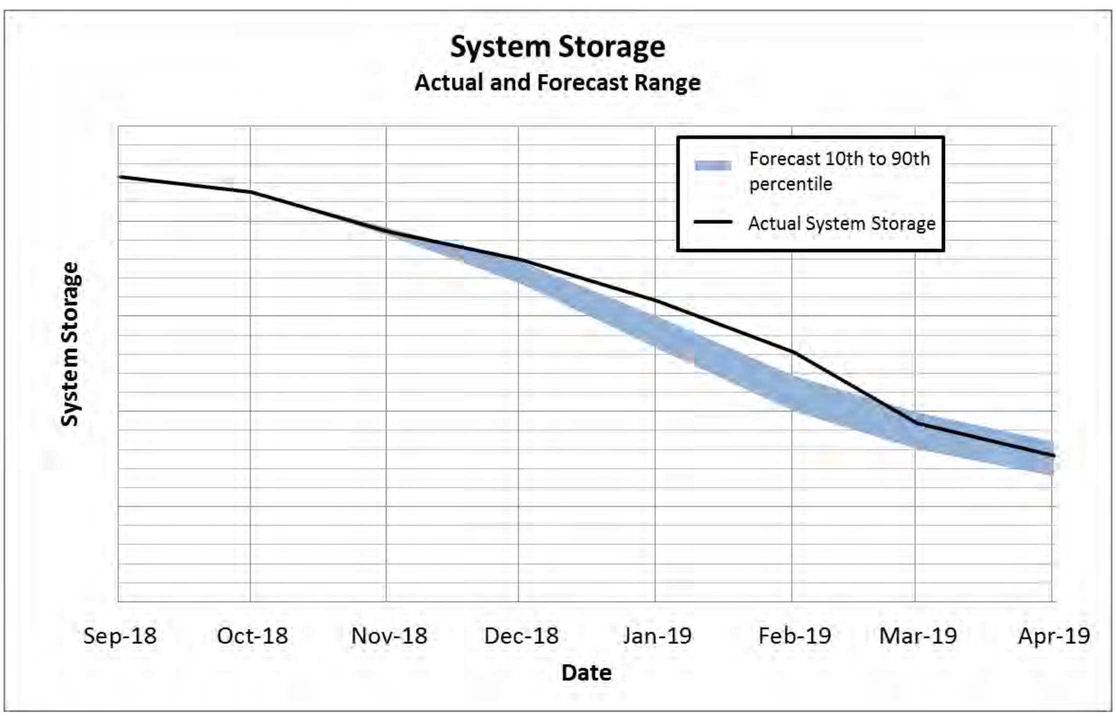
AMPC wishes to better understand the range of potential impacts water inflows have on Energy Study results and correspondingly on forecast revenue.

2.48.9 For the actuals available since October 1, 2018 please compare to the average storage level forecast used in the Energy Study (as provided above). Please comment on associated differences and the impact on costs and revenues. If this actual information is not currently available, please provide at the time of the Cost of Energy update, currently scheduled for October 18, 2019.

RESPONSE:

Actual information on System Storage as well as updated costs and revenues will be available at the time of the Cost of Energy update. However, monthly actual System Storage data is considered confidential in order to protect commercially sensitive information. As stated in BC Hydro's response to BCUC IR 1.20.2, publication of this information would enable third parties to model BC Hydro's system to estimate the depth of BC Hydro's energy need and to predict BC Hydro's import and export requirements.

The graph below illustrates how System Storage evolved over the period September 2018 through March 2019, relative to the range shown in the 10th to 90th percentile forecast from the October 2018 Energy Study. Relatively warm and wet weather through December and January resulted in less draft of System Storage than forecast in October. However, draft steepened in February 2019 with the onset of very cold weather in the major load centres.



49.0 Energy Study

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.3, pdf pp. 169-173

In response to AMPC IR 1.15.3 (at pdf pp. 169-173), BC Hydro provides a series of histogram charts comparing forecast ranges of system inflows for an ensemble of inflow forecasts with observed system inflows for the years F2015 to F2019. The charts are described as follows:

> The following charts are histograms showing the forecast system inflows for an ensemble of inflow forecasts. The x-axis is the percentage of normal for system inflows. For example, for fiscal 2015, the range of forecast inflows in March 2014 was from 88 to 108 per cent of normal. The observed system inflow for fiscal 2015 in the end was 101 per cent of normal. Please refer to BC Hydro's response to BCUC IR 1.31.1 for a description of how the forecasts are developed and used in the Energy Studies.

Reference (ii): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.8.2, pdf p. 183

At pdf p. 183, BC Hydro states that "BC Hydro has provided in its response to AMPC IR 1.15.3 a set of forecast distributions of system inflows that reflect the likelihood of low inflow conditions."

2.49.1 Please provide an explanation of what the y-axis represents for these charts and provide commentary to explain the differences between forecast and observed.

RESPONSE:

The charts provided in BC Hydro's response to AMPC IR 1.15.3 are histograms where the y-axis is a frequency.

The distribution graphed contains one data point for each inflow forecast (45 data points for fiscal 2019, 44 data points for fiscal 2018, etc.) and the y axis represents the number of data points that correspond to each 'bin' along the x axis.

For example, in the fiscal 2015 chart, the bar in the 88 per cent 'bin' represents one out of 41 ensemble forecasts, the bar in the 91 per cent 'bin' represents two out of 41 ensemble forecasts, and the bar in the 100 per cent 'bin' represents six out of 41 ensemble forecasts.

The histogram (red bars in chart) show the range and frequency of possible inflow outcomes that are forecast in March for the following fiscal year.

The blue bar in the chart represents what the actuals inflows (observed) were for the fiscal year. By the end of the fiscal year, all inflow has been observed and the histogram collapses to a single point.

The spread in the forecast inflow distribution assumes the current conditions based on snowpack built prior to March, but no knowledge of precipitation after that point in time. The spread therefore represents the potential range of variability in inflow due to the current snowpack volume and future precipitation across the ensemble forecasts.

For fiscal 2019, the observed inflow was outside of the range of what was forecast in March 2018, whereas for fiscal years 2015 through 2018 the observed inflow was within the range forecasted in March.

49.0 Energy Study

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.3, pdf pp. 169-173

In response to AMPC IR 1.15.3 (at pdf pp. 169-173), BC Hydro provides a series of histogram charts comparing forecast ranges of system inflows for an ensemble of inflow forecasts with observed system inflows for the years F2015 to F2019. The charts are described as follows:

> The following charts are histograms showing the forecast system inflows for an ensemble of inflow forecasts. The x-axis is the percentage of normal for system inflows. For example, for fiscal 2015, the range of forecast inflows in March 2014 was from 88 to 108 per cent of normal. The observed system inflow for fiscal 2015 in the end was 101 per cent of normal. Please refer to BC Hydro's response to BCUC IR 1.31.1 for a description of how the forecasts are developed and used in the Energy Studies.

Reference (ii): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.8.2, pdf p. 183

At pdf p. 183, BC Hydro states that "BC Hydro has provided in its response to AMPC IR 1.15.3 a set of forecast distributions of system inflows that reflect the likelihood of low inflow conditions."

2.49.2 Please provide corresponding background data for each graph.

RESPONSE:

The following table provides the corresponding background data for each graph provided in BC Hydro's response to AMPC IR 1.15.3.

Bin (%)	F2015	F2016	F2017	F2018	F2019
85	0	0	0	0	0
86	0	0	0	2	0
87	0	0	0	1	0
88	1	2	0	2	0
89	0	2	0	1	0
90	1	0	1	3	2
91	2	0	1	4	2

Bin (%)	F2015	F2016	F2017	F2018	F2019
92	2	1	2	3	0
93	2	2	0	2	2
94	2	3	4	3	1
95	1	1	0	5	1
96	2	3	3	5	1
97	4	2	2	2	2
98	3	8	3	2	5
99	3	5	2	2	2
100	6	1	6	3	2
101	3	3	2	1	10
102	2	3	3	2	4
103	3	1	4	0	4
104	1	2	4	1	3
105	2	2	2	0	1
106	0	0	2	0	1
107	0	1	1	0	0
108	1	0	0	0	0
109	0	0	1	0	1
110	0	0	0	0	0
111	0	0	0	0	0
112	0	0	0	0	1
113	0	0	0	0	0
114	0	0	0	0	0
115	0	0	0	0	0

49.0 Energy Study

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.3, pdf pp. 169-173

In response to AMPC IR 1.15.3 (at pdf pp. 169-173), BC Hydro provides a series of histogram charts comparing forecast ranges of system inflows for an ensemble of inflow forecasts with observed system inflows for the years F2015 to F2019. The charts are described as follows:

> The following charts are histograms showing the forecast system inflows for an ensemble of inflow forecasts. The x-axis is the percentage of normal for system inflows. For example, for fiscal 2015, the range of forecast inflows in March 2014 was from 88 to 108 per cent of normal. The observed system inflow for fiscal 2015 in the end was 101 per cent of normal. Please refer to BC Hydro's response to BCUC IR 1.31.1 for a description of how the forecasts are developed and used in the Energy Studies.

Reference (ii): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.8.2, pdf p. 183

At pdf p. 183, BC Hydro states that "BC Hydro has provided in its response to AMPC IR 1.15.3 a set of forecast distributions of system inflows that reflect the likelihood of low inflow conditions."

2.49.3 Please explain how "normal" is defined as mentioned in the preamble to the histogram charts provided.

RESPONSE:

In the preamble to the histogram charts provided, "normal" refers to the energy production capability of the system under average inflow conditions based on the same historical record as the ensemble of inflow forecasts that begin in 1973.

49.0 Energy Study

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.3, pdf pp. 169-173

In response to AMPC IR 1.15.3 (at pdf pp. 169-173), BC Hydro provides a series of histogram charts comparing forecast ranges of system inflows for an ensemble of inflow forecasts with observed system inflows for the years F2015 to F2019. The charts are described as follows:

> The following charts are histograms showing the forecast system inflows for an ensemble of inflow forecasts. The x-axis is the percentage of normal for system inflows. For example, for fiscal 2015, the range of forecast inflows in March 2014 was from 88 to 108 per cent of normal. The observed system inflow for fiscal 2015 in the end was 101 per cent of normal. Please refer to BC Hydro's response to BCUC IR 1.31.1 for a description of how the forecasts are developed and used in the Energy Studies.

Reference (ii): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.8.2, pdf p. 183

At pdf p. 183, BC Hydro states that "BC Hydro has provided in its response to AMPC IR 1.15.3 a set of forecast distributions of system inflows that reflect the likelihood of low inflow conditions."

2.49.4 Please confirm that BC Hydro's associated revenue requirement for each year provided would have been based on the halfway point between the ranges provided by the red bars (so for example, 98% of "normal" for F2015). If not confirmed, please add a bar that represents the results of the Energy Study for each year provided.

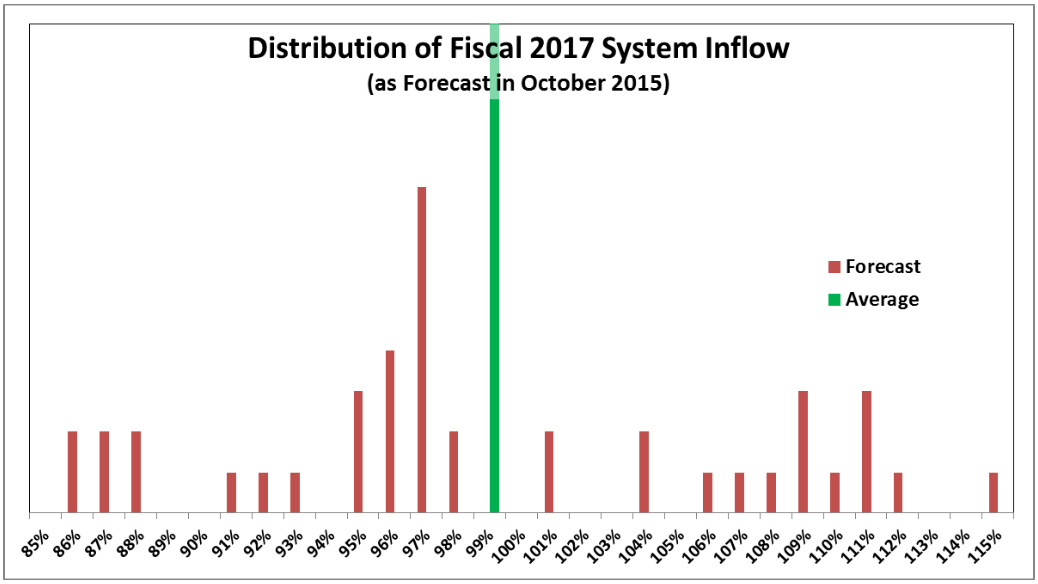
RESPONSE:

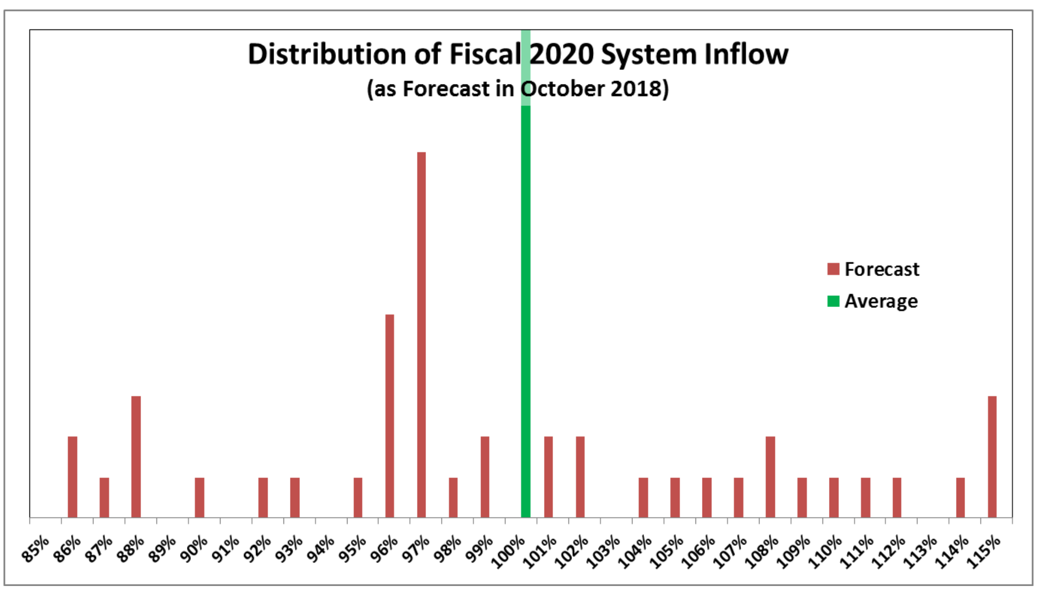
Not confirmed. BC Hydro's associated revenue requirement for each year provided would have depended on the timing of the inflow forecast underpinning the Cost of Energy in each application. The ranges provided by the red bars are based on forecasts in March for the following fiscal year, whereas the revenue requirement is based on an October Energy Study.

The histograms for each fiscal year inflow forecast that produced the forecast underpinning the Cost of Energy in each application are provided in the following charts. Note that in October there is no information on the year's snow pack

accumulation so that the inflow forecasts in October for the following fiscal year tend to represent average conditions.

In the charts below, the green central bar denotes the average forecast of system inflow, in contrast to the histograms provided in BC Hydro's response to AMPC IR 1.15.3 where the single blue bar denotes the observed value. The first graph is for the first year of the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application Test Period and the second refers to the first year of the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application Test Period.





49.0 Energy Study

Reference (i): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.3, pdf pp. 169-173

In response to AMPC IR 1.15.3 (at pdf pp. 169-173), BC Hydro provides a series of histogram charts comparing forecast ranges of system inflows for an ensemble of inflow forecasts with observed system inflows for the years F2015 to F2019. The charts are described as follows:

> The following charts are histograms showing the forecast system inflows for an ensemble of inflow forecasts. The x-axis is the percentage of normal for system inflows. For example, for fiscal 2015, the range of forecast inflows in March 2014 was from 88 to 108 per cent of normal. The observed system inflow for fiscal 2015 in the end was 101 per cent of normal. Please refer to BC Hydro's response to BCUC IR 1.31.1 for a description of how the forecasts are developed and used in the Energy Studies.

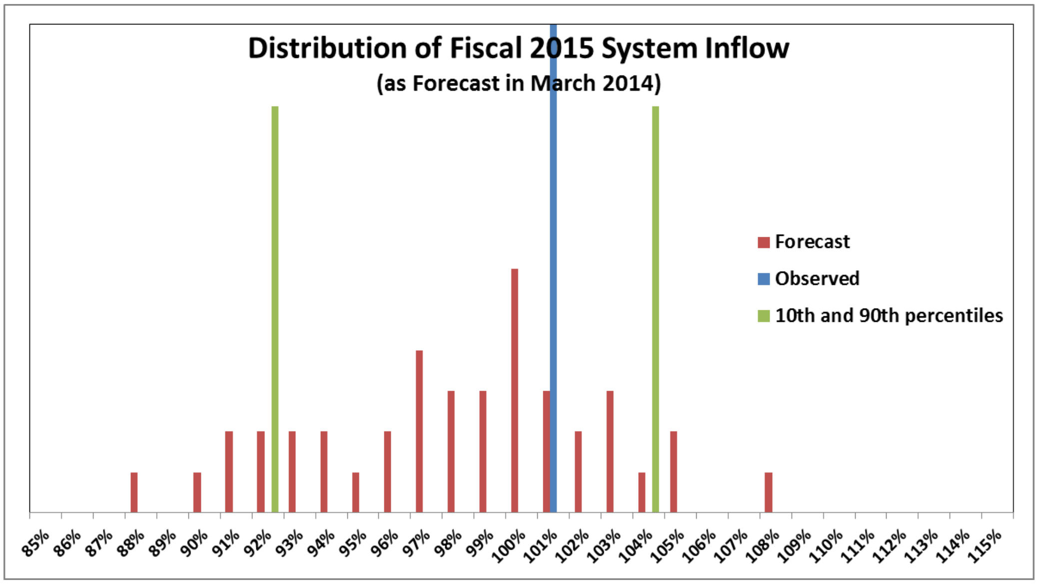
Reference (ii): Exhibit B-6, BC Hydro Response to AMPC IR 1.15.8.2, pdf p. 183

At pdf p. 183, BC Hydro states that "BC Hydro has provided in its response to AMPC IR 1.15.3 a set of forecast distributions of system inflows that reflect the likelihood of low inflow conditions."

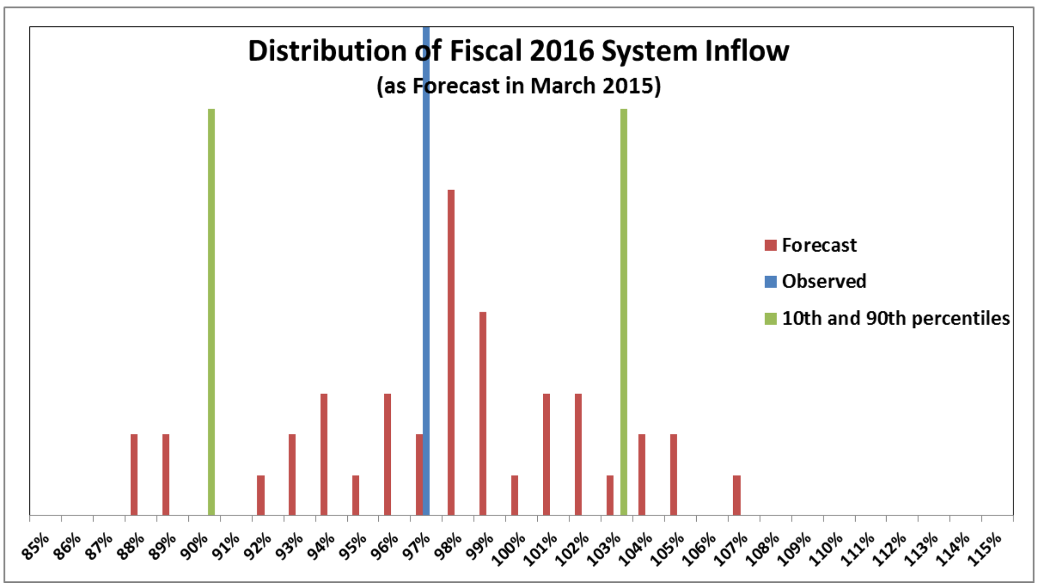
2.49.5 Regarding BC Hydro's response to AMPC 1.15.8.2, please specify which set of forecast reflects the probability of low inflow conditions. Please explain the percentile distribution BC Hydro quantifies as 'low inflow conditions' (i.e. below the X percentile).

RESPONSE:

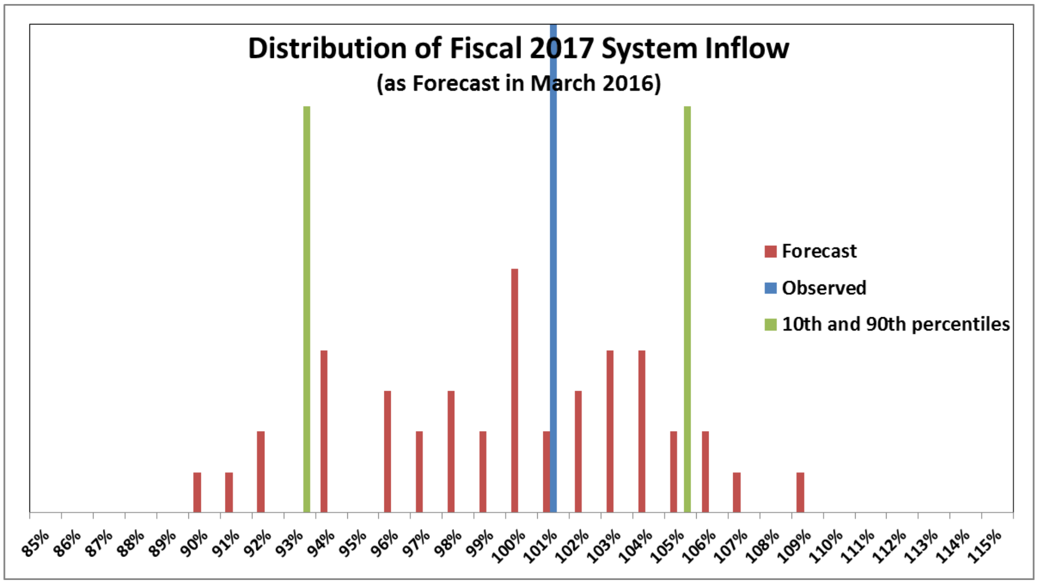
BC Hydro does not have a specific definition of low inflow conditions that is used for any operational decision making purpose. With reference to the system inflow distributions presented in BC Hydro's response to AMPC IR 1.15.3, we have annotated these distributions in the graphs below to show the tenth and ninetieth percentiles of the forecast System Inflow. In other words, 80 per cent of the forecast outcomes are between the two green lines. These percentiles can be used as a guide to distinguish outcomes resulting from low inflow conditions.



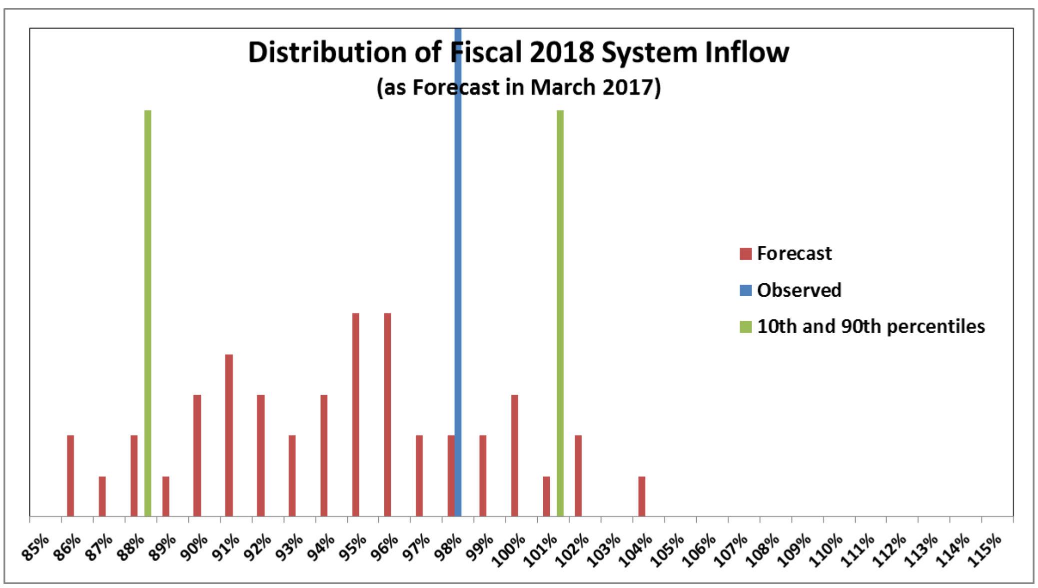
Distribution of Fiscal 2015 System Inflow
(as Forecast in March 2014)
Forecast
Observed
10th and 90th percentiles
85% 86% 87% 88% 89% 90% 91% 92% 93% 94% 95% 96% 97% 98% 99% 100% 101% 102% 103% 104% 105% 106% 107% 108% 109% 110% 111% 112% 113% 114% 115%



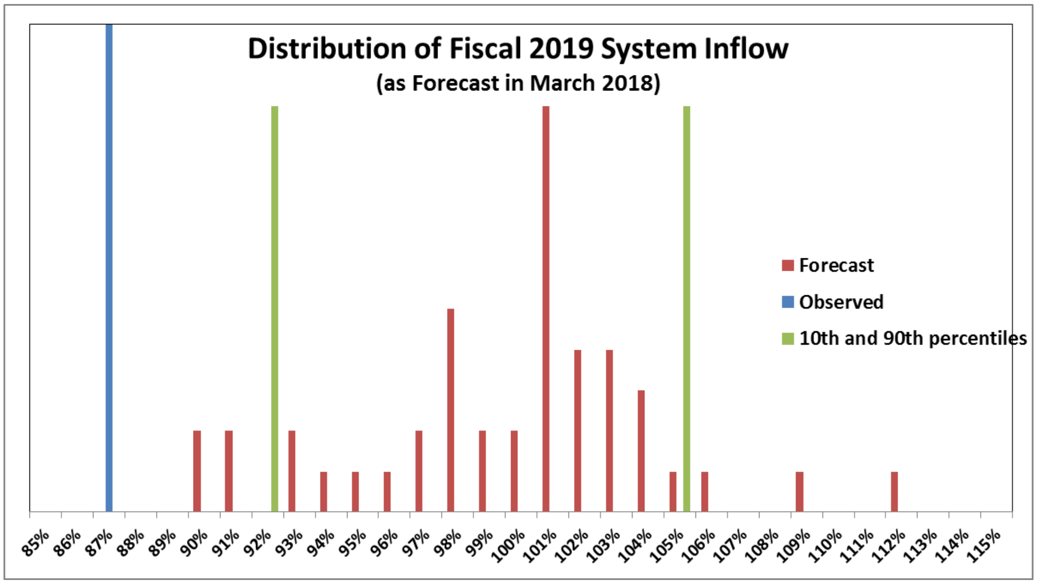
Distribution of Fiscal 2016 System Inflow
(as Forecast in March 2015)
Forecast
Observed
10th and 90th percentiles
85% 86% 87% 88% 89% 90% 91% 92% 93% 94% 95% 96% 97% 98% 99% 100% 101% 102% 103% 104% 105% 106% 107% 108% 109% 110% 111% 112% 113% 114% 115%



Distribution of Fiscal 2017 System Inflow
(as Forecast in March 2016)
Forecast
Observed
10th and 90th percentiles
85% 86% 87% 88% 89% 90% 91% 92% 93% 94% 95% 96% 97% 98% 99% 100% 101% 102% 103% 104% 105% 106% 107% 108% 109% 110% 111% 112% 113% 114% 115%



Distribution of Fiscal 2018 System Inflow
(as Forecast in March 2017)
Forecast
Observed
10th and 90th percentiles
85% 86% 87% 88% 89% 90% 91% 92% 93% 94% 95% 96% 97% 98% 99% 100% 101% 102% 103% 104% 105% 106% 107% 108% 109% 110% 111% 112% 113% 114% 115%



Distribution of Fiscal 2019 System Inflow
(as Forecast in March 2018)
Forecast
Observed
10th and 90th percentiles
85%
86%
87%
88%
89%
90%
91%
92%
93%
94%
95%
96%
97%
98%
99%
100%
101%
102%
103%
104%
105%
106%
107%
108%
109%
110%
111%
112%
113%
114%
115%

50.0 Water Rentals

Reference: Exhibit B-6, BC Hydro Response to AMPC IR 1.16.2 and Attachment, pdf pp. 187-188

In its response, BC Hydro provides its water rental rates and costs from F2014 to F2021.

Reference: Exhibit B-1, BC Hydro RRA Application, Appendix A, Schedule 4.0, p. 38, pdf p. 1189

On pdf p. 1189., BC Hydro provides its unit cost for water rentals for F2017-F2021.

Cost of Energy
($ 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
	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

AMPC is seeking confirmation from BC Hydro on how its water rental rates compare to those in other Canadian jurisdictions. AMPC has provided a table below that sets out the water rental rates in different Canadian jurisdictions.

2.50.1 Please confirm that water rental rates captured in the table below are accurate, to the best of BC Hydro's knowledge. If not confirmed or if BC Hydro is aware of or relies on other water rental rates for other Canadian jurisdictions, please provide that information including all relevant documents.

Jurisdiction	**Water Rental Rates ($/MWh)**	**Source**
BC	$7.8	Exhibit B-1, BC Hydro RRA Application, Appendix A, Schedule 4.9, p. 38, pdf p. 1189
Newfoundland & Labrador	$2.58	Newfoundland and Labrador Regulation 64/03**,** Water Power Rental Regulations, 2003 under the Water Resources Act (O.C. 2003-230) Amended by: 69/16. Section (4) Rates. Available online: https://assembly.nl.ca/Legislation/sr/regulations/rc030064.htm
Quebec	$3.25	Régis Québec Official Source, R-13 Watercourses Act, updated June 5, 2018. Available online: http://legisquebec.gouv.qc.ca/en/ShowDoc/cs/R-13

Jurisdiction	Water Rental Rates ($/MWh)	Source
Manitoba	$3.34	The Water Power Act, Water Power Regulation, C.C.S.M. c. W60, Last amendment included M.R. 77/2010, available online: http://web2.gov.mb.ca/laws/regs/current/_pdf-regs.php?reg=25/88%20R
Ontario	$3.80	Ontario Ministry of Finance, Gross Revenue Charge, last modified May 15, 2017. Available online: https://www.fin.gov.on.ca/en/tax/grc/index.html; Rate applied is effectively equal to $3.80/MWh (9.5% of $40,000 per GWh).
Saskatchewan	$5.68	The Water Power Rental Regulations, 2018 being Chapter W-6 Reg 4 (effective April 19, 2018). Available online: http://www.publications.gov.sk.ca/freelaw/documents/English/Regulations/Regulations/W6R4.pdf

RESPONSE:

BC Hydro notes that the number provided for B.C. is not correct. The table above shows BC Hydro's weighted average water rental unit cost at $7.8/MWh, as presented in Appendix A, schedule 4.0, line 16 (referred incorrectly in the table in the preamble as schedule 4.9), and is different from the water rental rate charged by the Government of B.C. The weighted average water rental unit cost included in schedule 4.0, line 16 includes generation output charges, capacity related charges, miscellaneous water license fees, and other adjustments under the water coordination agreements.

Water rental rates in B.C. for 2019 are $1.404/MWh for the first 160,000 megawatt hours of generation output in the prior calendar year and $6.546 for each subsequent megawatt hour of generation output in the prior calendar year. These and other applicable rates are available online via the link below:

https://www2.gov.bc.ca/assets/gov/environment/air-land-water/water/water-rights/waterpower_rental_rates_2018.pdf

BC Hydro has not contacted the other jurisdictions to check what their water rental rates are. In comparing water rental rates, there are different costs beyond the $/MWh value and how the values are escalated is also important. As shown in the discussion above regarding BC Hydro's water rental rates, these other costs complicate the ability to compare water rental rates across jurisdictions.

90.0 Reference: Exhibit B-6, BCOAPO 1.2.1
Energy, Mines and Petroleum Resources Statement
https://archive.news.gov.bc.ca/releases/news_releases_2017-2021/2018EMPR0004-000311.htm

On March 1, 2018 the Ministry of Energy, Mines and Petroleum Resources issued the following statement:

For Immediate Release
2018EMPR0004-000311
March 1, 2018

Ministry of Energy, Mines and Petroleum Resources

Government will help low-income families manage electricity costs

VICTORIA – Minister of Energy, Mines and Petroleum Resources Michelle Mungall has issued the following statement on the B.C. Utilities Commission (BCUC) decision on the BC Hydro rate freeze:

"I am disappointed the BCUC turned down BC Hydro's request for a one-year rate freeze, and instead, approved the previous government's rate increase.

"We completely understand the affordability crisis so many families face, and will be taking action quickly to address the need to reduce electricity costs for those who need it most.

"Government will work with BC Hydro and customer groups on a lifeline rate program. The program could mean that people who have demonstrated need would have access to a lower rate for their electricity*. (emphasis added)*

"In addition, starting in May, BC Hydro residential customers who find themselves in an emergency – such as loss of employment, unanticipated medical expenses or pending eviction for example – will be eligible for a grant toward their outstanding BC Hydro bill. The grant is up to $600 and does not need to be repaid.

"Last month, BC Hydro announced enhanced measures to help customers manage higher winter bills, including a winter payment plan, giving

customers the option to spread bill payments over a six-month period, and increased funding for low-income energy-conservation programs.

"To lower electricity costs for B.C. businesses and industries, we are phasing out the provincial sales tax (PST) on electricity. Following the 50% reduction that started on Jan. 1, 2018, government will completely eliminate the PST on non-residential electricity on April 1, 2019. Residential use of electricity is already PST-exempt.

"Eliminating the PST on electricity will translate into savings of more than $150 million annually for B.C. businesses. This will help them create more jobs for British Columbians, expand into new markets, and reinvest in new technologies.

"Our government will also undertake a comprehensive review of BC Hydro to make it work for people. The review will identify changes and cost savings to keep rates low, while ensuring BC Hydro has the resources it needs to continue to provide clean, safe and reliable electricity. We expect to announce the scope and process for the review in the coming weeks.

"We respect the BCUC's work and diligence as British Columbians' independent regulator. Although disappointed with its decision, we understand the commission's concerns and will work to address them, while implementing ways to make life more affordable for B.C. families."

2.90.1 If as, as the response to BCOAPO 1.2.1 suggests, there are no current plans to implement lifeline rates, please reconcile this with the above Statement issued by the Ministry.

RESPONSE:

BC Hydro recognizes the importance of providing support to our low-income customers. While the existing policy framework does not enable BC Hydro to offer lifeline rates, BC Hydro continues to advance other affordability measures.

Specifically, BC Hydro's January 2019 Mandate Letter from the Minister of Energy, Mines and Petroleum Resources directs BC Hydro to:

> **"Continue delivering affordability measures, including demand-side management programs targeted to low-income ratepayers, and any other measures that may be identified through development of BC's Poverty Reduction Strategy."**

A copy of the January 2019 Mandate Letter is available at:
https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/openness-accountability/bch-mandate-letter-2019-2020.pdf

As discussed further in BC Hydro's response to BCOAPO IR 1.2.1, BC Hydro has expanded its demand-side management programs for low income customers in the Application and has implemented a Customer Crisis Fund. In addition, BC Hydro is examining options to simplify the default residential rate and will consult with customers and stakeholders, including the Low Income Advisory Council, on potential rate design concepts prior to any application to the BCUC.

In addition, based on the Evidentiary Update, the approvals BC Hydro is seeking would result a rate decrease of 0.99 per cent in fiscal 2021.

90.0 Reference: Exhibit B-6, BCOAPO 1.2.1
Energy, Mines and Petroleum Resources Statement
https://archive.news.gov.bc.ca/releases/news_releases_2017-2021/2018EMPR0004-000311.htm

On March 1, 2018 the Ministry of Energy, Mines and Petroleum Resources issued the following statement:

For Immediate Release
2018EMPR0004-000311
March 1, 2018

Ministry of Energy, Mines and Petroleum Resources

Government will help low-income families manage electricity costs

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"I am disappointed the BCUC turned down BC Hydro's request for a one-year rate freeze, and instead, approved the previous government's rate increase.

"We completely understand the affordability crisis so many families face, and will be taking action quickly to address the need to reduce electricity costs for those who need it most.

"Government will work with BC Hydro and customer groups on a lifeline rate program. The program could mean that people who have demonstrated need would have access to a lower rate for their electricity*. (emphasis added)*

"In addition, starting in May, BC Hydro residential customers who find themselves in an emergency – such as loss of employment, unanticipated medical expenses or pending eviction for example – will be eligible for a grant toward their outstanding BC Hydro bill. The grant is up to $600 and does not need to be repaid.

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customers the option to spread bill payments over a six-month period, and increased funding for low-income energy-conservation programs.

"To lower electricity costs for B.C. businesses and industries, we are phasing out the provincial sales tax (PST) on electricity. Following the 50% reduction that started on Jan. 1, 2018, government will completely eliminate the PST on non-residential electricity on April 1, 2019. Residential use of electricity is already PST-exempt.

"Eliminating the PST on electricity will translate into savings of more than $150 million annually for B.C. businesses. This will help them create more jobs for British Columbians, expand into new markets, and reinvest in new technologies.

"Our government will also undertake a comprehensive review of BC Hydro to make it work for people. The review will identify changes and cost savings to keep rates low, while ensuring BC Hydro has the resources it needs to continue to provide clean, safe and reliable electricity. We expect to announce the scope and process for the review in the coming weeks.

"We respect the BCUC's work and diligence as British Columbians' independent regulator. Although disappointed with its decision, we understand the commission's concerns and will work to address them, while implementing ways to make life more affordable for B.C. families."

2.90.2 Please indicate the current status of the joint initiative referenced in the above Statement to develop lifeline rates.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.2.1 where we explain that while the existing policy framework does not enable BC Hydro to offer lifeline rates, BC Hydro continues to advance other affordability measures.

91.0 Reference: Exhibit B-6, AMC 1.2.1

2.91.1 How has BC Hydro assured itself (and other ratepayers) that the Freshet Rate sales are truly incremental and would not have occurred in the absence of the rate?

RESPONSE:

BC Hydro filed its Freshet Rate Pilot Final Evaluation Report with the BCUC on December 17, 2018. The Final Evaluation Report describes the actions that BC Hydro has taken to verify the Freshet Energy Rate energy sales that were truly incremental.

As described in the Final Evaluation Report, analysis of load shifting was undertaken to determine the Freshet Energy Rate energy sales that were truly incremental. Load shifting represents energy sales that would have occurred in the absence of the Freshet Energy Rate.

As described in section 3.1.7 of the Final Evaluation Report, load shift is deemed to occur when a Freshet Energy Rate customer changes the timing of electricity consumption to buy more during freshet months and less in non-freshet months for no net change in total annual energy consumption.

BC Hydro considers that the definition of load shift energy should also include use of Freshet Energy Rate (RS 1892) as a replacement for service under other rate schedules (e.g. RS 1823 or RS 1880) for energy that the customer would have purchased anyway, such as for natural load growth.

As described in section 3.1.7.1 of the Final Evaluation Report, BC Hydro sought to identify and verify the energy consumption impact of any load shifting events by Freshet Energy Rate participant customers in Year 1 (2016) and Year 2 (2017) of the Freshet Energy Rate Pilot. BC Hydro's steps to assess load shifting impacts are summarized below:

- **Step 1: Survey all RS 1892 customer participants to identify specific actions taken to increase load during the 2016 and 2017 Freshet Period;**
- **Step 2: Prepare a data set for participant customers with actual RS 1892 energy sales in Year 1 (26 sites) and Year 2 (32 sites);**
- **Step 3: Compare each customer's fiscal 2017 and fiscal 2018 annual energy sales with fiscal 2016 annual energy sales under RS 1823;**

- **Step 4: For customers with lower RS 1823 energy sales BC Hydro reviewed the documentation for each customer to identify events that were verified to reduce energy consumption;**
- **Step 5: For customers with higher RS 1823 energy sales BC Hydro reviewed the documentation for each customer to identify events that were verified to increase energy consumption; and**
- **Step 6: Assess the financial impact of the load shift. This step included determining the volume of energy associated with each load-shift event, and comparison of actual RS 1892 revenue with the revenue that would have been collected under the otherwise applicable rate.**

92.0 Reference: Exhibit B-6, BCOAPO 1.3.2.1 and 1.3.3

2.92.1 Please provide a schedule that sets out the performance measure targets and actual results for 2018/19.

RESPONSE:

The following table summarizes the performance measure targets and actual results for 2018/19, as listed in BC Hydro's 2018/19 Annual Service Plan Report published in July 2019 and available at: https://www.bchydro.com/toolbar/about/accountability_reports/financial_reports/annual_reports.html

Please note that lower results are better for:

- **1.a. SAIDI;**
- **1.b SAIFI;**
- **1.c Key Generating Facility Forced Outage Factor;**
- **4.a Zero Fatality & Serious Injury; and**
- **4.b Lost Time Injury Frequency.**

Performance Measure		2018/19 Targets	2018/19 Actuals
1.a	SAIDI (System Average Interruption Duration Index) [Total outage duration (in hours) of sustained interruptions experienced by an average customer in a year]	3.30	2.96
1.b	SAIFI (System Average Interruption Frequency Index) [Total number of sustained interruptions experienced by an average customer in a year (excluding major events)]	1.40	1.35
1.c	Key Generating Facility Forced Outage Factor (%)	1.80	1.61
1.d	CSAT Index [Customer Satisfaction Index: % of customers satisfied or very satisfied]	85.0	87.7
1.e	Progressive Aboriginal Relations Designation	Gold	Gold

Performance Measure		2018/19 Targets	2018/19 Actuals
2.a	Competitive Rates	1st quartile	1st quartile
2.b	Project Budget to Actual Cost	Within +5% to -5% of budget excluding project reserve amounts	+0.34% on $8.03 billion
3.a	Energy Conservation Portfolio (New incremental GWh/year)	800	868
3.b	Clean Energy (%)	93.0	97.8
3.c	New Clean Supply (%)	100	100
4.a	Zero Fatality & Serious Injury [Loss of life or the injury has resulted in a permanent disability]	0	0
4.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]	0.85	0.87
4.c	Timely Completion of Corrective Actions (%)	93	98

92.0 Reference: Exhibit B-6, BCOAPO 1.3.2.1 and 1.3.3

2.92.2 Please explain why expected lower levels of performance in 2018/19 with respect to the Lost Time Injury Frequency performance measure justify reducing the target for 2019/20 to 2021/22.

RESPONSE:

As discussed in BC Hydro's response to BCOAPO IR 1.3.2.1, the Lost Time Injury Frequency target was adjusted from 0.75 to 0.80 for fiscal 2020 and fiscal 2021. Lost Time Injury Frequency targets are modified from year to year, based on performance, so that they encourage incremental efforts while remaining attainable. BC Hydro has achieved consistent and measureable reductions in Lost Time Injury Frequency from 1.04 in fiscal 2017, to 0.88 in fiscal 2018 and to 0.87 in fiscal 2019.

93.0 Reference: Exhibit B-5, BCUC 1.2.1 and 1.3.1
Exhibit B-6, BCOAPO 1.10.1 and GJOSHE 1.15.1

2.93.1 Regardless whether or not BC Hydro "categorizes" its costs to distinguish those incurred for export, the response to BCUC 1.3.1 states that "With the amendments, the recovery in rates of expenditures on infrastructure and energy purchases associated with producing power that is surplus to BC Hydro's domestic needs is no longer be prohibited. Accordingly, the BCUC may allow BC Hydro to recover prudently incurred expenditures for export in rates, similar to how the BCUC assesses expenditures for domestic purposes." Are there any expenditures/costs in the proposed F2020 or F2021 revenue requirements (either capital or OM&A) that are for the purpose of supporting exports?

RESPONSE:

This answer also responds to BCOAPO IR 2.93.1.1.

BC Hydro has not proposed any project and has not procured any energy for the specific purpose of supporting exports over the test period.

BC Hydro has acquired resources (e.g., contracts with IPPs) to meet self-sufficiency based on average water conditions from our heritage resources and our mid-load forecast. Planning to average expected conditions will result in operating years in which BC Hydro has net surplus sales or net market purchases depending on a number of factors including actual customer loads, market prices and system inflows. Once acquired, BC Hydro optimizes the system to maximize value to the ratepayers.

93.0 Reference: Exhibit B-5, BCUC 1.2.1 and 1.3.1
Exhibit B-6, BCOAPO 1.10.1 and GJOSHE 1.15.1

2.93.1 Regardless whether or not BC Hydro "categorizes" its costs to distinguish those incurred for export, the response to BCUC 1.3.1 states that "With the amendments, the recovery in rates of expenditures on infrastructure and energy purchases associated with producing power that is surplus to BC Hydro's domestic needs is no longer be prohibited. Accordingly, the BCUC may allow BC Hydro to recover prudently incurred expenditures for export in rates, similar to how the BCUC assesses expenditures for domestic purposes." Are there any expenditures/costs in the proposed F2020 or F2021 revenue requirements (either capital or OM&A) that are for the purpose of supporting exports?

2.93.1.1 If yes, please indicate what they are and where they are included.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.93.1 where we state that BC Hydro has not proposed any project and has not procured any energy for the specific purpose of supporting exports over the test period.

93.0 Reference: Exhibit B-5, BCUC 1.2.1 and 1.3.1
Exhibit B-6, BCOAPO 1.10.1 and GJOSHE 1.15.1

2.93.2 Given the response to GJOSHE 1.15.1, is it reasonable to conclude that, in the short-term, DSM related expenditures are justified primarily on the basis that they will support increased exports?

RESPONSE:

This answer also responds to BCOAPO IR 2.93.2.1.

DSM-related expenditures are not justified on the basis that they will support increased exports. Rather, DSM expenditures are supported on the basis that they are a low cost resource that:

- **Lowers utility costs for customers;**
- **Supports Government policy objectives on affordability as well as multiple energy objectives under the *Clean Energy Act;***
- **Engages customers and enhances relationships; and**
- **Saves customers money on their bills.**

BC Hydro is using the market price as the avoided cost for the utility cost test for internal decision making. This means that DSM expenditures are cost-effective during the energy surplus period and provide a net benefit for customers by reducing BC Hydro's revenue requirement.

93.0 Reference: Exhibit B-5, BCUC 1.2.1 and 1.3.1
Exhibit B-6, BCOAPO 1.10.1 and GJOSHE 1.15.1

2.93.2 Given the response to GJOSHE 1.15.1, is it reasonable to conclude that, in the short-term, DSM related expenditures are justified primarily on the basis that they will support increased exports?

2.93.2.1 If not, why not?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.93.2 where we explain that DSM expenditures are not justified on the basis that they will support increased exports.

94.0 Reference: Exhibit B-5, BCUC 1.173.1

2.94.1 Please provide a copy of or a link to "BC Hydro's Report on Demand-Side Management Activities for fiscal 2018".

RESPONSE:

BC Hydro's Report on Demand-Side Management Activities for fiscal 2018 is provided in Appendix Z of the Application, starting on page 17.

94.0 Reference: Exhibit B-5, BCUC 1.173.1

2.94.2 Does the 5,301 GWh in Row A represent the persisting savings in F2021 from DSM programs initiatives undertaken in F2008 to F2018?

RESPONSE:

This answer also responds to BCOAPO IR 2.94.2.2.

Confirmed. The 5,301 GWh represents the persisting savings in fiscal 2021 at the system level (i.e., including losses) from DSM initiatives undertaken in fiscal 2008 to fiscal 2018.

94.0 Reference: Exhibit B-5, BCUC 1.173.1

2.94.2 Does the 5,301 GWh in Row A represent the persisting savings in F2021 from DSM programs initiatives undertaken in F2008 to F2018?

2.94.2.1 If not, what does it represent and why it the appropriate value to use in the calculation?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.94.2 for information on the persisting savings.

94.0 Reference: Exhibit B-5, BCUC 1.173.1

2.94.3 Does the 1,799 GWh in Row B represent the persisting savings in F2021 from DSM programs initiatives planned for F2019 to F2021?

RESPONSE:

This answer also responds to BCOAPO IR 2.94.3.1.

Confirmed. The 1,799 GWh represents the persisting savings in fiscal 2021 at the system level (i.e., including losses) from DSM initiatives planned for fiscal 2019 to fiscal 2021.

94.0 Reference: Exhibit B-5, BCUC 1.173.1

2.94.3 Does the 1,799 GWh in Row B represent the persisting savings in F2021 from DSM programs initiatives planned for F2019 to F2021?

2.94.3.1 If not, what does it represent and why it the appropriate value to use in the calculation?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.94.3 for information on the persisting savings.

94.0 Reference: Exhibit B-5, BCUC 1.173.1

2.94.4 Is the 58,735 GWh in Row E the actual Total Gross System Requirements for F2008 or a weather normalized actual value?

RESPONSE:

The 58,735 GWh is the actual (non-weather normalized) total gross requirements for the integrated system for fiscal 2008, as shown in BC Hydro's November 2012 Load Forecast.

94.0 Reference: Exhibit B-5, BCUC 1.173.1

2.94.4 Is the 58,735 GWh in Row E the actual Total Gross System Requirements for F2008 or a weather normalized actual value?

2.94.4.1 If the former, how would the calculation change if the weather normalized actual value for F2018 was used?

RESPONSE:

BC Hydro believes the reference in the question to fiscal 2018 was meant to be fiscal 2008.

The weather-normalized value for the actual total gross requirements for the integrated system would be 58,391 GWh for fiscal 2008.

By using this value in place of the actual total gross requirements for the integrated system of 58,735 GWh for fiscal 2008, DSM as a percentage of load growth at fiscal 2021 since fiscal 2008 would change from 103 per cent to 98 per cent.

95.0 Reference: Exhibit B-6, CEC 1.4.1 & 1.43.4 and INCE 1.1.1

The response to CEC 1.4.1 states that:

"The success of our capital planning process as a whole over time is best assessed through the information provided in BC Hydro's Service Plan. The Service Plan contains performance measures such as SAIDI, SAIFI and Key Generating Facility Forced Outage Factor which provide an indication of the impact of capital investment on system performance over time."

However, the response to INCE 1.1.1 states:

"The BC Hydro system is highly complex and dynamic and it is difficult to make a direct link between the SAIDI, SAIFI and Generation Facility Forced Outage Factor performance metrics and investments in the system. These metrics are influenced by factors beyond capital and maintenance investment including operational procedures and uncontrollable events".

2.95.1 Please reconcile the proposed use of performance measures such as SAIDI, SAIFI and Key Generating Facility Forced Outage Factor evaluate the success of BC Hydro's capital planning process with the response to INCE 1.1.1 which suggests that there is no direct link between the two.

RESPONSE:

The two questions noted in the preamble differ in that CEC IR 1.4.1 asked how the BCUC can determine the success of the capital planning process "as a whole over time" whereas INCE IR 1.1.1 requested evidence of the "relationship between cost and reliability for each of the indicated performance metrics and yearly operations spending".

BC Hydro maintains that, as a whole over time, the trend in system performance metrics such as SAIDI, SAIFI and Generation Facility Forced Outage Factor, as reported in the Service Plan, is the appropriate way for the BCUC to gauge the success of how BC Hydro is managing and operating the system. The capital investments identified through the capital planning process are a key contributor to the management of BC Hydro's assets. Maintenance and operating procedures also have a significant influence on system performance metrics as well as uncontrollable events.

95.0 Reference: Exhibit B-6, CEC 1.4.1 & 1.43.4 and INCE 1.1.1

The response to CEC 1.4.1 states that:

"The success of our capital planning process as a whole over time is best assessed through the information provided in BC Hydro's Service Plan. The Service Plan contains performance measures such as SAIDI, SAIFI and Key Generating Facility Forced Outage Factor which provide an indication of the impact of capital investment on system performance over time."

However, the response to INCE 1.1.1 states:

"The BC Hydro system is highly complex and dynamic and it is difficult to make a direct link between the SAIDI, SAIFI and Generation Facility Forced Outage Factor performance metrics and investments in the system. These metrics are influenced by factors beyond capital and maintenance investment including operational procedures and uncontrollable events".

2.95.2 Is there a difference between: i) measuring the success of the capital planning process (i.e., to what extent does the capital planning process appropriately identify the required expenditures to meet BC Hydro's planning objectives or put, another way, is the proposed capital plan the appropriate capital plan) and ii) measuring the success in implementing a given capital plan.

RESPONSE:

This answer also responds to BCOAPO IRs 2.95.2.1, 2.95.2.2 and 2.95.2.3.

BC Hydro is interpreting the question to ask whether there is a difference in how we measure or determine:

(i) That we have the right processes to identify recommended capital investments and develop the appropriate capital plan; and

(ii) That we have achieved the desired outcomes of a particular capital plan.

In BC Hydro's response to CEC IR 1.4.2, we explained that BC Hydro evaluates success in its capital planning processes through ongoing achievement of Service Plan targets, demonstrating continuous improvements to the capital planning process and its governance, as well as third party evaluation of our asset management practices.

Two of the goals in the 2019/20 to 2021/22 Service Plan, provided in Appendix E to the Application, relate to the capital planning process: Reliable Service and Affordable Bills. Examples of performance measures for these goals include:

- **System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Forced Outage Factor; and**
- **Quartile ranking based on Hydro-Quebec's Comparison of Electricity Prices in Major North American Cities and Project Budget to Actual Cost.**

These same measures demonstrate our success in implementing our capital plans over time. Although the capital plan is updated annually as explained in section 6.3 of Chapter 6 of the Application, each capital plan is not an end in itself but rather is part of an ongoing enterprise capital planning process. Therefore, the results of an individual capital plan from a particular year are not measurable in terms of specific outcomes, given the long duration of some capital projects and the long lives of many of BC Hydro's assets. Some of the projects initiated as a result of a particular capital plan enter service years later, after the capital plan has been updated multiple times.

The annual update of the capital plan responds to changing system and customer needs and adapts the capital portfolio. The capital plan developed in a particular year leads to the initiation of new projects and modifications to some continuing projects. Project Completion and Evaluation Reports are used to evaluate whether individual investment objectives, impacts and benefits were achieved. Please refer to section 6.4.7.9 in Chapter 6 of the Application for further discussion on the Implementation phase of the PPM project lifecycle including project completion.

95.0 Reference: Exhibit B-6, CEC 1.4.1 & 1.43.4 and INCE 1.1.1

The response to CEC 1.4.1 states that:

"The success of our capital planning process as a whole over time is best assessed through the information provided in BC Hydro's Service Plan. The Service Plan contains performance measures such as SAIDI, SAIFI and Key Generating Facility Forced Outage Factor which provide an indication of the impact of capital investment on system performance over time."

However, the response to INCE 1.1.1 states:

"The BC Hydro system is highly complex and dynamic and it is difficult to make a direct link between the SAIDI, SAIFI and Generation Facility Forced Outage Factor performance metrics and investments in the system. These metrics are influenced by factors beyond capital and maintenance investment including operational procedures and uncontrollable events".

2.95.2 Is there a difference between: i) measuring the success of the capital planning process (i.e., to what extent does the capital planning process appropriately identify the required expenditures to meet BC Hydro's planning objectives or put, another way, is the proposed capital plan the appropriate capital plan) and
ii) measuring the success in implementing a given capital plan.

2.95.2.1 If, in BC Hydro's view, there is no difference – please explain why.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.95.2 where we discuss the difference.

95.0 Reference: Exhibit B-6, CEC 1.4.1 & 1.43.4 and INCE 1.1.1

The response to CEC 1.4.1 states that:

"The success of our capital planning process as a whole over time is best assessed through the information provided in BC Hydro's Service Plan. The Service Plan contains performance measures such as SAIDI, SAIFI and Key Generating Facility Forced Outage Factor which provide an indication of the impact of capital investment on system performance over time."

However, the response to INCE 1.1.1 states:

"The BC Hydro system is highly complex and dynamic and it is difficult to make a direct link between the SAIDI, SAIFI and Generation Facility Forced Outage Factor performance metrics and investments in the system. These metrics are influenced by factors beyond capital and maintenance investment including operational procedures and uncontrollable events".

2.95.2 Is there a difference between: i) measuring the success of the capital planning process (i.e., to what extent does the capital planning process appropriately identify the required expenditures to meet BC Hydro's planning objectives or put, another way, is the proposed capital plan the appropriate capital plan) and
ii) measuring the success in implementing a given capital plan.

2.95.2.2 If there is a difference, are the SAIDI, SAIFI and Generation Facility Forced Outage Factor performance metrics measuring the success of the capital planning process?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.95.2 where we explain that BC Hydro evaluates success in its capital planning processes through ongoing achievement of Service Plan targets and performance measures, including System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Forced Outage Factor.

95.0 Reference: Exhibit B-6, CEC 1.4.1 & 1.43.4 and INCE 1.1.1

The response to CEC 1.4.1 states that:

"The success of our capital planning process as a whole over time is best assessed through the information provided in BC Hydro's Service Plan. The Service Plan contains performance measures such as SAIDI, SAIFI and Key Generating Facility Forced Outage Factor which provide an indication of the impact of capital investment on system performance over time."

However, the response to INCE 1.1.1 states:

"The BC Hydro system is highly complex and dynamic and it is difficult to make a direct link between the SAIDI, SAIFI and Generation Facility Forced Outage Factor performance metrics and investments in the system. These metrics are influenced by factors beyond capital and maintenance investment including operational procedures and uncontrollable events".

2.95.2 Is there a difference between: i) measuring the success of the capital planning process (i.e., to what extent does the capital planning process appropriately identify the required expenditures to meet BC Hydro's planning objectives or put, another way, is the proposed capital plan the appropriate capital plan) and ii) measuring the success in implementing a given capital plan.

2.95.2.3 If there is a difference, what performance metrics does BC Hydro use to measure its success in implementing a given capital plan?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.95.2 where we discuss the measures that demonstrate our success in implementing our capital plans over time.

96.0 Reference: Exhibit B-5, BCUC 1.5.1 and 1.10.1
Exhibit B-1, pages 3-27 to 3-30

2.96.1 Please provide a schedule that sets out the forecast LNG load for the test period based on the 2016 Load Forecast.

RESPONSE:

The following table provides the forecast LNG load before losses for the Test Period (fiscal 2020 to fiscal 2021) from the May 2016 Load Forecast:

Fiscal Year (Plan)	LNG Load (GWh)
2020	236
2021	1,182

96.0 Reference: Exhibit B-5, BCUC 1.5.1 and 1.10.1
Exhibit B-1, pages 3-27 to 3-30

2.96.2 With respect to the load forecast for large industrial customers, why is the proposed approach expected to improve the forecast accuracy for specific segments and for which specific segments is this expected to occur (per Exhibit B-1, page 3-29)?

RESPONSE:

Applying the binary method over the near term (up to three years) is expected to improve the load forecast accuracy for those segments where probability-weighted forecasts are influenced by account-specific risk assessments.

For example, in the pulp and paper segment we assess the likelihood of operational shut-downs and the timing of those closures, and in the shale gas segment we assess the likelihood of new start-ups and the associated timing.

Operational shutdowns or new start-ups are binary in nature (i.e., the facilities are either operating or not operating). Therefore any associated probability-weighted (i.e., risk-adjusted) forecast will result in either a positive or negative variance on an actual basis, since the forecast is a projection of future sales with uncertainty around a number of risk elements, such as the likelihood and timing of closures and start-ups.

In contrast, the binary method makes a determination, considering the same risk assessment used to develop the probability-weighted load forecast, on whether the existing facility will continue to operate or shutdown. It is possible that an incorrect binary determination will be made (e.g., we assume that a facility will continue to operate for a certain period, but the facility actually shuts down; or vice versa). However, if an incorrect binary determination is made, the resulting variance will be higher (worse) than the variance resulting from applying the probability-weighted approach. If the correct binary determination is made, then the resulting variance will be lower (better) relative to the probability-weighted approach.

The load forecast variances experienced in recent years have been partially due to relatively small risk adjustments to specific customer forecasts. For example, in the pulp and paper segment some facilities with closure risk over a specific time period are more likely to continue operations than to shut down within that period. For this reason BC Hydro believes it is more likely that correct binary determinations will be made, which will result in an improved load forecast relative to a probability-weighted load forecast.

While the examples described in the parentheses above apply to facilities facing closure risk (e.g., within the pulp and paper segment), the same concept applies to new facilities (e.g., within the natural gas segment).

The example below illustrates the forecast load and potential variances for a plant with a 100 GWh load that has a 25 per cent probability of closure.

				If Plant Stays Operational		If Plant Closes	
	Total Load if Plant is Operating (GWh)	Closure Risk (%)	Load Forecast (GWh)	Actual Load (GWh)	Variance (Actual - Forecast) (GWh)	Actual Load (GWh)	Variance (Actual - Forecast) (GWh)
Previous Method: Load Adjusted by Probability-Weighting	100	25	75	100	(25)	0	(75)
Current Method: Binary Assessment	100	25	100	100	0	0	(100)

Under the probability-weighting method, if the plant stayed operational, there would be a 25 GWh variance attributable to the discounting of the plant’s load. Several plants discounted like this could add up to a large variance across a segment or sub-sector. Under the current binary assessment method, if the plant stayed operational, there would be no variance between their forecast and actual load. If the incorrect binary determination was made and it was assumed the plant remained operational when it actually shut down, a greater variance would result.

96.0 Reference: Exhibit B-5, BCUC 1.5.1 and 1.10.1
Exhibit B-1, pages 3-27 to 3-30

2.96.3 With respect to the October 2018 residential and commercial load forecasts (BCUC 1.5.1, pages 3-5 of 9), why was the calibration period updated to the most recent 10 years instead of using a longer period that also included the original period used as well as the more recent years where actual data is now available?

RESPONSE:

A rolling 10-year calibration period provides an appropriate balance between having a sufficiently large sample size to establish statistically sound regression (120 data points) with a data set that is sufficiently current such that changing trends in electricity consumption and drivers are reflected in the models. There is also a consistency benefit to using a 10-year rolling period. BC Hydro has been developing forecasts with the statistically adjusted end use (SAE) models for residential and commercial sectors using a rolling 10-year calibration period since 2006. Using a 10-year rolling calibration period is also consistent with the period used to establish normal temperature assumptions for the forecast.

96.0 Reference: Exhibit B-5, BCUC 1.5.1 and 1.10.1
Exhibit B-1, pages 3-27 to 3-30

2.96.4 With respect to the October 2018 residential and commercial load forecasts (BCUC 1.5.1, pages 3, 5 & 7 of 9), what is the basis for the updated (mainly higher) projection of average efficiency for the various end uses of electricity?

RESPONSE:

The basis for the updated (higher) efficiency projections for the residential and commercial sectors comes from updated average efficiency projections provided by the U.S. Energy Information Administration (EIA). The May 2016 Load Forecast used the 2015 EIA projection of average efficiency and the October 2018 Load Forecast used the 2018 EIA projection. For several residential and commercial end uses of electricity and appliances there is a higher efficiency projection in the EIA's 2018 forecast.

The EIA model is periodically recalibrated with actual purchased equipment stock and this has led to a revised higher projection of average efficiency relative to previous projections. The last recalibration was published in 2016 after BC Hydro issued its May 2016 Load Forecast and was therefore not reflected in that forecast. The EIA projections are also updated on an annual basis and these updates can include the impact of recently approved legislation on codes and standard requirements of efficiency equipment used in the residential and commercial sectors. The most recent EIA projection was incorporated into the October 2018 Load Forecast. Model recalibrations and projection updates can both account for the higher efficiency projections between the two vintages of EIA forecasts.

96.0 Reference: Exhibit B-5, BCUC 1.5.1 and 1.10.1
Exhibit B-1, pages 3-27 to 3-30

2.96.5 With respect to the impact of DSM savings (BCUC 1.5.1, page 9 of 9) associated with the 2016 Load Forecast, please provide a schedule that sets out the assumed annual savings in F2016 to F2024 associated with DSM programs implemented in F2016-F2018.

RESPONSE:

This answer also responds to BCOAPO IR 2.96.6.

The table below compares the requested forecast of DSM savings from the Previous Application (Column A) with actual savings (Column B) over the same timeframe.

Column A represents the forecast of acquired energy savings at the customer meter resulting from DSM activities from fiscal 2016 to fiscal 2018, including the persistence of the savings out to fiscal 2024. This forecast is consistent with the DSM Plan[1] included in the 2016 Load Forecast.

Column B represents the actual acquired energy savings resulting from DSM activities from fiscal 2016 to fiscal 2018, including the persistence of savings out to fiscal 2024. These actual savings are not included in the DSM savings forecast within the 2018 Load Forecast. The 2018 Load Forecast only includes the DSM savings and the persistence of savings from DSM activities starting in fiscal 2019, as fiscal 2019 is the first year of the forecast. This is to avoid double-counting, as actual DSM savings are embedded within actual sales up to the end of fiscal 2018, which forms the anchor point for the load forecast.

Acquired Energy Savings at Customer Meter (GWh)	Forecast (A)	Actuals (B)
F2016	609	572
F2017	1,243	1,217
F2018	1,775	1,782
F2019	2,073	1,839
F2020	2,032	1,766
F2021	2,016	1,740

[1] **This is the bottom up DSM Plan, as described in footnote 22 on page 3-33 of the Previous Application**

Acquired Energy Savings at Customer Meter (GWh)	Forecast (A)	Actuals (B)
F2022	1,986	1,675
F2023	1,946	1,648
F2024	1,926	1,631

Actual persisting savings beyond fiscal 2018 were lower than forecast primarily due to lower than anticipated savings over the fiscal 2016 to fiscal 2018 timeframe from the General Service Lamps Regulation, and a delay in timing of TMP projects originally planned for fiscal 2018. These lower savings were offset over the fiscal 2016 to fiscal 2018 timeframe by an increase in savings with shorter persistence.

96.0 Reference: Exhibit B-5, BCUC 1.5.1 and 1.10.1
Exhibit B-1, pages 3-27 to 3-30

2.96.6 With respect to the impact of DSM savings (BCUC 1.5.1, page 9 of 9) associated with the 2018 Load Forecast, please provide a schedule that sets out the actual annual savings in F2016 to F2024 associated with DSM programs implemented in F2016-F2018 embedded in the load forecast.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.96.5 for the actual savings from fiscal 2016 to fiscal 2018 DSM activities.

97.0 Reference: Exhibit B-6, BCOAPO 1.18.4.2

2.97.1 Based on the response to BCOAPO 1.18.4.2 there appears to be no adjustment made to the load forecast to account for the loss of persistence in savings related to DSM activities prior to F2019. Please confirm that this is the case.

RESPONSE:

This answer also responds to BCOAPO IRs 2.97.1.1 and 2.97.1.2.

Confirmed. There were no adjustments made to the October 2018 Load Forecast to account for the loss of savings persistence related to DSM activities prior to fiscal 2019. The model projections were not adjusted to account for the loss of DSM persistence over the estimation period for the reasons discussed below.

Any quantification of the loss of savings persistence related to DSM activities prior to fiscal 2019 would be uncertain. DSM measures are assigned a persistence value for the purposes of DSM cost-effectiveness analysis, as a conservative assumption for how long the savings are attributable to the utility's actions. However, from a load forecast perspective, it is possible that the reduction in consumption associated with those DSM measures continue beyond the assigned persistence period (e.g., if a customer replaces the efficient measure with a measure of similar efficiency when it reaches its end of life). Due to these uncertainties, it is not possible to estimate the impact during the test period of the loss of savings persistence.

Even if estimates of the loss of savings persistence were possible, further testing of the statistical significance of these estimates would be required amongst the other load drivers included in the models, such as economic variables, temperature and average energy efficiency.

Given this, we believe it is better to develop statistically sound forecasting models and forecasts with drivers that are well supported. This same rationale applies to the large industrial customer based forecasts and light industrial forecasts.

97.0 Reference: Exhibit B-6, BCOAPO 1.18.4.2

2.97.1 Based on the response to BCOAPO 1.18.4.2 there appears to be no adjustment made to the load forecast to account for the loss of persistence in savings related to DSM activities prior to F2019. Please confirm that this is the case.

2.97.1.1 If confirmed, what is the impact in the test years of the loss in savings related to DSM activities prior to F2019?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.97.1.

97.0 Reference: Exhibit B-6, BCOAPO 1.18.4.2

2.97.1 Based on the response to BCOAPO 1.18.4.2 there appears to be no adjustment made to the load forecast to account for the loss of persistence in savings related to DSM activities prior to F2019. Please confirm that this is the case.

2.97.1.2 If not confirmed, please explain how the loss in persisting savings related to DSM activities prior to F2019 is accounted for in the load forecast.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.97.1.

98.0 Reference: Exhibit B-6, BCOAPO 1.19.2

2.98.1 Are there more recent forecasts available from either the Conference Board of Canada or the Ministry of Finance? If so, please expand the schedule provided in response to BCOAPO 1.19.2 to include the more recent forecasts.

RESPONSE:

There is a more recent forecast available from the Ministry of Finance, which was issued in February 2019. The Conference Board of Canada is in the process of updating its economic forecast as part of BC Hydro's next load forecast cycle.

The table below provides an expanded schedule, which includes the most recent forecast from the Ministry of Finance in addition to the values provided in BC Hydro's response to BCOAPO IR 1.19.2.

GDP Comparison Table – Fiscal 2019 to Fiscal 2022

Calendar Year	June 2018 Conference Board Commercial GDP Growth (%)	June 2018 Conference Board Total B.C. GDP Growth (%)	September 2018 Ministry of Finance Total B.C. GDP Growth (%)	February 2019 Ministry of Finance Total B.C. GDP Growth (%)
2019	2.6	2.2	1.8	2.4
2020	2.6	2.3	2.0	2.3
2021	2.2	1.8	2.0	2.1
2022	2.0	2.1	2.0	2.0

The above table includes two corrections to BC Hydro's response to BCOAPO IR 1.19.2. First, the years are labelled as calendar years rather than fiscal years. Second, the June 2018 Conference Board Total B.C. GDP Growth rates are based on Real GDP by Expenditure rather than Total Output. The differences between these two forecasts are minor.

99.0 Reference: Exhibit B-6, BCOAPO 1.22.2

2.99.1 How is the Light Industrial and Commercial Account forecast developed?

RESPONSE:

This answer also responds to BCOAPO IR 2.99.2.

The total number of accounts for the combined light industrial and commercial sectors in the October 2018 Load Forecast was developed based on computing a historical average of account growth over the past five years ending fiscal 2018. The accounts forecast was developed as follows:

1. **The historical average growth was calculated for two separate segments which include the light industrial and commercial customers under 35 kW per month and light industrial and commercial customers over 35 kW per month;**
2. **The forecast of accounts for fiscal 2019 was developed by adding the historical average to the base year (i.e., fiscal 2018) ending number of accounts for each customer segment (under 35 kW and over 35 kW);**
3. **The forecast for each segment for other years was subsequently increased by the historical average growth; and**
4. **The total number of accounts for the entire sector (total of light industrial and commercial) is computed by the sum of the forecasts for the two segments.**

The methodology described above differs from the account forecast methodology that was used in the May 2016 Load Forecast. This methodology change explains why the October 2018 Load Forecast of light industrial and commercial accounts is different (lower) than the May 2016 Load Forecast even though there is a small positive variance (higher) in actual accounts relative to the May 2016 Load Forecast account forecast for the Test Period.

The May 2016 forecast of accounts was developed on a total customer basis for each of the 15 sub-regions using retail sales projections. The growth in retail sales was used to forecast account growth in each sub-region. The forecast of the total number of accounts was the sum of the forecasts across the 15 sub-regions. However, because historical annual growth in accounts in some of the 15 sub-regions is uneven (up and down), it is difficult to establish a statistical relationship between account growth and retail sales growth. Consequently, a historical growth trend approach was adopted.

As of the end of fiscal 2019 both methods have yielded relatively small variances. The variance in accounts based on the October 2018 Load Forecast methodology is 599 accounts or 0.3 per cent and the variance based on the May 2016 Load Forecast methodology is -244 accounts or -0.1 per cent.

99.0 Reference: Exhibit B-6, BCOAPO 1.22.2

2.99.2 Given that the actual number of Light Industrial and Commercial accounts in F2018 is higher than the May 2016 forecast, please explain why the forecast account numbers for the test years are lower in the current forecast.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.99.1.

99.0 Reference: Exhibit B-6, BCOAPO 1.22.2

2.99.3 How is the Large Industrial Account forecast developed?

RESPONSE:

The forecast of the number of large industrial accounts is based on the sum of the number of existing accounts in the base year (i.e., fiscal 2018), plus the number of new customer accounts, less the number of closed accounts.

100.0 Reference: Exhibit B-6, BCSEA 1.5.3

2.100.1 The referenced excel file does not appear to be attached to the response. Please provide.

RESPONSE:

Attachment 1 to this response provides the attachment to BC Hydro’s response to BCSEA IR 1.5.3 as a working excel file.

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(Accessible by opening the Attachments Tab in Adobe)

101.0 Reference: Exhibit B-6, GJOSHE 1.10.1

2.101.1 How is the distribution substation peak demand forecast for each substation developed?

RESPONSE:

The distribution substation peak demand forecast for each substation consists of four different substation peak forecast scenarios: mid substation forecast before and after incremental Demand-Side Management (DSM), and high substation forecast before and after incremental DSM. The process to prepare both the mid and high forecasts takes approximately six months to complete.

As discussed below, the development of the mid substation forecast and high substation forecast are based on the mid guideline and high guideline and system-wide DSM savings.

Mid Substation Forecast

The first step in developing a mid substation forecast for each of BC Hydro's individual substations is the development of a mid guideline, before DSM, for 15 geographic areas (sub-regions). These guidelines are developed using deterministic and econometric methods with various inputs. Some of the inputs include historical temperature normalized substation peak demands, rate impacts, residential account forecasts, and distribution energy forecasts from BC Hydro's end use model projections as well as other adjustments such as peak load projections for emerging sectors, including electric vehicles, cannabis and cryptocurrency. These mid guidelines are prepared by BC Hydro's Load Forecasting team (Energy Planning department), which also prepares regional and total system energy and peak forecasts. The mid guideline for each sub-region represents the expected total peak demand for all of the substations within that region.

Using the mid guidelines for the 15 sub-regions, distribution planners in the Distribution Planning department develop the mid substation forecasts, before DSM, for individual substations by allocating the aggregated peak demand growth projections in a sub-region to individual substations in that region, based on local knowledge and analysis of historical trends in the substation peak demand.

The Load Forecasting team and Distribution Planning department collaborate to share information on factors that may impact the substation peak demand forecasts.

High Substation Forecast

Similar to the development of the mid substation forecast, the first step in developing the high substation forecast is the development of a high guideline for each of the 15 regions. The high guidelines, before DSM, are developed using BC Hydro's Monte Carlo simulation model. This model is used to develop a high peak demand forecast for the base load in the four main service regions and the results then are allocated among the 15 sub-regions. The high guideline for each of the 15 sub-regions is also supplemented with other peak loads from the emerging sectors, which are not captured in the Monte Carlo Model.

The distribution planners develop the high substation forecasts before DSM for individual substation by applying the ratio of high guidelines and mid guidelines to the mid substation forecasts.

Mid substation forecasts and high substation forecasts after incremental DSM are developed by allocating system-wide DSM savings amongst the individual distribution substations.

The individual substation forecasts are also supplemented by additional information on local electric system operations such as substation load transfers.

101.0 Reference: Exhibit B-6, GJOSHE 1.10.1

2.101.2 How does BC Hydro ensure that its system peak demand (which is developed by a coincident summation of the distribution substation forecast and transmission peak demands) is consistent with the total system energy forecast?

RESPONSE:

BC Hydro undertakes the following steps so that its system peak demand forecast is consistent with the total system energy forecast:

- **The process to develop the transmission connected (large industrial) loads for peak demand and energy is a unified process where both forecasts are developed on a customer by customer basis. The drivers of the large industrial energy forecast generally also apply to the development of peak forecasts. Developing both forecasts with shared inputs achieves consistency between the peak forecast and energy forecast at the total transmission level, as well as their respective contributions to the total system peak and energy forecasts; and**
- **The process to develop the total system distribution peak forecast begins with development of a distribution peak guideline forecast for the 15 sub-regions. The peak guidelines are a key input to developing individual substation forecasts. The guidelines are developed using the same distribution energy forecasts and residential accounts forecasts that are also used to develop the total distribution system energy forecasts. As such, consistency between peak and energy forecasts at the total distribution system level is achieved by using common inputs and drivers.**

102.0 Reference: Exhibit B-6, INCE 1.8.5

The response states "For the residential and commercial sectors, the model sales projections (i.e., before DSM) are based on our SAE forecasting models that utilize the U.S. Energy Information Administration (EIA) forecast of stock average efficiency of end use of electricity".

2.102.1 How does BC Hydro ensure that between the efficiency improvements assumed in the SAE forecasting models and the incremental DSM savings that are subsequently removed from the forecast there is no "double counting" of future efficiency savings?

RESPONSE:

As part of the load forecast process, BC Hydro undertakes a comparison of the U.S. Energy Information Administration (EIA) assumptions and the codes and standards included in BC Hydro's DSM plan to identify areas of overlap.

Where there is overlap, adjustments are made to the residential and commercial SAE model projections so that there is no double counting. This process is described in section 12 of Appendix O of the Application.

103.0 Reference: Exhibit B-5, BCUC 1.15.1.1

2.103.1 Do the values in Table 1 of the response (totaling $1.3 M) represent the difference in the costs for referenced EPAs as between the costs in the F2019 Plan (per the F2019 RRA) and the costs in F2021 per the current RRA?

RESPONSE:

Confirmed.

103.0 Reference: Exhibit B-5, BCUC 1.15.1.1

2.103.1 Do the values in Table 1 of the response (totaling $1.3 M) represent the difference in the costs for referenced EPAs as between the costs in the F2019 Plan (per the F2019 RRA) and the costs in F2021 per the current RRA?

2.103.1.1 If not, what do the values represent?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.103.1.

British Columbia Old Age Pensioners' Organization Et Al Information Request No. **2.103.2** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 2
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

103.0 Reference: Exhibit B-5, BCUC 1.15.1.1

2.103.2 What would be the difference in total costs in F2021 for these EPAs as between: i) the costs assuming they were renewed on the same terms as the initial agreements and ii) the renewal assumptions used in the Application? (Note: If there is also a change in volumes, please also indicate the change in volumes assumed and the difference in $/MWh)

RESPONSE:

This response includes confidential information that pertains to our August 2019 Cost of Energy Evidentiary Update, in accordance with Order No. G-146-19, which has been redacted in the public version of this response. The un-redacted version of the response is being made available to the BCUC only.

The Application uses the price and volume assumptions from the Biomass Energy Program, as was contemplated for Phase 1 of the Government of B.C.'s Comprehensive Review of BC Hydro, for the renewal of biomass EPAs that are due to expire before December 31, 2021. If these EPAs were renewed under the same terms as the initial agreements rather than the renewal assumptions in the Application, the total renewal volume in fiscal 2021 would be higher by 268 GWh and the total cost for the same period would be higher by $44.1 million.

The average unit cost in fiscal 2021 is $95.6/MWh using the renewal assumptions in the Application. However, if the agreements were renewed using the same terms as the initial agreement, the average unit costs in fiscal 2021 would be $107.1/MWh.

BC Hydro notes that the Biomass Energy Program volumes and costs were revised slightly in the Evidentiary Update, as follows:

- **Forecast volumes were updated to reflect additional historical performance in fiscal 2019; and**
- **Forecast costs were updated to reflect the change in volumes above and that load offset energy in the Biomass Energy Program is valued at $85/MWh (Fiscal 2019$), not the $85/MWh (Fiscal 2018$) assumption used in the Application.**

Based on the Evidentiary Update values, if these EPAs were renewed under the same terms as the initial agreements, the total renewal volume in fiscal 2021 would be higher by [redacted] GWh and the associated total cost would be higher by $[redacted] million. The average unit cost for these EPAs in fiscal 2021 is $[redacted] /MWh.

However, if the agreements were renewed using the same terms as the initial agreement, the average unit costs in fiscal 2021 would be $[redacted]/MWh.

Please refer to BC Hydro's response to BCUC IR 1.15.2 for additional information on the IPP forecast methodology in the Application.

**104.0 Reference: Exhibit B-5, BCUC 1.15.1, 1.15.2 and 1.15.2.1
BC Hydro's EPA Renewal Application (Sechelt Creek Hydro, Brown Lake Hydro, and Walden North Hydro), Exhibit B-5, BCUC 1.8.4**

In response to BCUC 1.8.4 from the proceeding dealing with BC Hydro's EPA Renewal Application, BC Hydro states:

'BC Hydro's LRB shows it will not need to acquire new energy resources for many years to come. Given potential policy changes that may affect BC Hydro arising from ongoing government review and other energy related policies, on top of technology cost uncertainty in the long term, BC Hydro recently adopted the use of market price as a conservative interim assumption for evaluating energy during surplus and deficit periods.'

The response to BCUC 1.15.2.1 in the current proceeding indicates that this "conservative interim assumption" was used in the case of the two run of the river EPAs due to expire during the test period. However, the response also indicates that this "conservative interim assumption" was not adopted for facilities eligible for the Biomass Energy Program or facilities with other benefits.

2.104.1 Why was the "conservative interim assumption" not adopted for facilities eligible for the Biomass Energy Program?

RESPONSE:

The conservative interim assumption to use a market-based approach was not adopted for facilities eligible for the Biomass Energy Program because, as described in Appendix C of the Application, the Biomass Energy Program considers fuel supply availability, cost effectiveness, impacts on BC Hydro ratepayers and other government priorities (page 25 of report). As a result, BC Hydro, in consultation with the Government of B.C., developed prices that provide a balance of these considerations.

Please refer to BC Hydro's response to BCUC IR 1.15.2.1 and BCOAPO IR 2.155.3 for additional information related to the adoption and use of the market price as a conservative interim assumption for evaluating BC Hydro's opportunity cost of energy.

104.0 Reference: Exhibit B-5, BCUC 1.15.1, 1.15.2 and 1.15.2.1
BC Hydro's EPA Renewal Application (Sechelt Creek Hydro, Brown Lake Hydro, and Walden North Hydro), Exhibit B-5, BCUC 1.8.4

In response to BCUC 1.8.4 from the proceeding dealing with BC Hydro's EPA Renewal Application, BC Hydro states:

'BC Hydro's LRB shows it will not need to acquire new energy resources for many years to come. Given potential policy changes that may affect BC Hydro arising from ongoing government review and other energy related policies, on top of technology cost uncertainty in the long term, BC Hydro recently adopted the use of market price as a conservative interim assumption for evaluating energy during surplus and deficit periods.'

The response to BCUC 1.15.2.1 in the current proceeding indicates that this "conservative interim assumption" was used in the case of the two run of the river EPAs due to expire during the test period. However, the response also indicates that this "conservative interim assumption" was not adopted for facilities eligible for the Biomass Energy Program or facilities with other benefits.

2.104.1 Why was the "conservative interim assumption" not adopted for facilities eligible for the Biomass Energy Program?

2.104.1.1 What approach was used for these facilities?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.15.2, which provides the assumptions utilized for biomass facilities eligible for the Biomass Energy Program in the IPP forecast in the Application.

104.0 Reference: Exhibit B-5, BCUC 1.15.1, 1.15.2 and 1.15.2.1
BC Hydro's EPA Renewal Application (Sechelt Creek Hydro, Brown Lake Hydro, and Walden North Hydro), Exhibit B-5, BCUC 1.8.4

In response to BCUC 1.8.4 from the proceeding dealing with BC Hydro's EPA Renewal Application, BC Hydro states:

'BC Hydro's LRB shows it will not need to acquire new energy resources for many years to come. Given potential policy changes that may affect BC Hydro arising from ongoing government review and other energy related policies, on top of technology cost uncertainty in the long term, BC Hydro recently adopted the use of market price as a conservative interim assumption for evaluating energy during surplus and deficit periods.'

The response to BCUC 1.15.2.1 in the current proceeding indicates that this "conservative interim assumption" was used in the case of the two run of the river EPAs due to expire during the test period. However, the response also indicates that this "conservative interim assumption" was not adopted for facilities eligible for the Biomass Energy Program or facilities with other benefits.

2.104.2 With respect to Table 1 in BCUC 1.15.1, please indicate for which EPAs: i) the original contract expired prior to the test period and new contract has been concluded, ii) the original contract expired prior to the test period but new contract has yet to be concluded, and iii) the original contract will expire during the test period. (Note: Based on the response to BCUC 1.15.2.1 there should be two run of the river and six biomass EPAs in the third category).

RESPONSE:

The public version of the response to this information request has been redacted to maintain confidentiality. The un-redacted version of this response is being made available to the BCUC only, in order to protect IPPs' commercial interests. The public disclosure of the redacted information could also impact BC Hydro's commercial interests and ongoing negotiations related to the EPAs.

BC Hydro understands the word "concluded" in the question to mean "executed". BC Hydro notes that for projects in category 1, not all agreements that have been executed have completed the regulatory review under section 71 of the *Utilities Commission Act*. BC Hydro also notes that for projects in category 2 and

category 3[1], BC Hydro may or may not proceed with a new contract. For this reason, we have made a modification to the category 2 description.

The table below indicates the EPAs in each of the categories, as of October 1, 2018, which were taken into consideration for Figure 4-2 of the Application. Please refer to BC Hydro's response to BCUC IR 1.17.1 for an explanation of why Figure 4-2 in Chapter 4 of the Application is not meant to be a comprehensive representation of all of the changes in the IPP forecast between vintages. BC Hydro also clarifies in regards to the note in parentheses in the question, one of the run of river EPAs discussed in BC Hydro's response to BCUC IR 1.15.2.1 (Robson Valley) was not included in the Table 1 of BC Hydro's response to BCUC IR 1.15.1.[2]

Categorization of EPA Renewals in Figure 4-2 of the Application

Category	Description	EPAs
1	The original contract expired prior to the test period and new contract has been concluded	Hydro: Akolkolex, Soo River, Boston Bar, Doran Taylor, Brown Lake, Sechelt Creek
2	The original contract expired prior to the test period	Hydro: Seaton Creek[3]
3	The original contract will expire during the test period.	Hydro: Coats IPP Biomass: Armstrong Wood Waste, Celgar Green, Howe Sound Green, NWE Williams Lake, PGP Bio Energy, Skookumchuck Power

1 The biomass agreements included in Category 3 are exempted from BCUC review under the Direction to the British Columbia Utilities Commission Respecting the Biomass Energy Program.

2 As noted in BC Hydro's response to BCUC IR 1.15.1, there were two other EPAs, for Morehead Creek and Robson Valley, which were not captured in the indicative analysis for Figure 4-2 of the Application. If they had been included in the Figure 4-2 indicative analysis, Morehead Creek and Robson Valley would have appeared in category 2 because as of October 1, 2018, their EPAs were expected to expire prior to the beginning of the test period. However, since October 1, 2018, the Robson Valley EPA has been extended to [redacted], which, if included as part of Figure 4-2, would have moved that EPA into category 3 (original contract expires during the test period). The Morehead Creek EPA expired in December 2018 and there is no new contract.

3 The Seaton Creek EPA expired in November 2018 and there is no new contract.

104.0 Reference: Exhibit B-5, BCUC 1.15.1, 1.15.2 and 1.15.2.1
BC Hydro's EPA Renewal Application (Sechelt Creek Hydro, Brown Lake Hydro, and Walden North Hydro), Exhibit B-5, BCUC 1.8.4

In response to BCUC 1.8.4 from the proceeding dealing with BC Hydro's EPA Renewal Application, BC Hydro states:

'BC Hydro's LRB shows it will not need to acquire new energy resources for many years to come. Given potential policy changes that may affect BC Hydro arising from ongoing government review and other energy related policies, on top of technology cost uncertainty in the long term, BC Hydro recently adopted the use of market price as a conservative interim assumption for evaluating energy during surplus and deficit periods.'

The response to BCUC 1.15.2.1 in the current proceeding indicates that this "conservative interim assumption" was used in the case of the two run of the river EPAs due to expire during the test period. However, the response also indicates that this "conservative interim assumption" was not adopted for facilities eligible for the Biomass Energy Program or facilities with other benefits.

2.104.2 With respect to Table 1 in BCUC 1.15.1, please indicate for which EPAs: i) the original contract expired prior to the test period and new contract has been concluded, ii) the original contract expired prior to the test period but new contract has yet to be concluded, and iii) the original contract will expire during the test period. (Note: Based on the response to BCUC 1.15.2.1 there should be two run of the river and six biomass EPAs in the third category).

2.104.2.1 Does the "conservative interim assumption" for evaluating energy during surplus and deficit periods apply to all EPAs in categories (ii) and (iii)? If not, why not?

RESPONSE:

No. Of the EPAs listed in BC Hydro's response to BCOAPO IR 2.104.2, the interim market approach has been or will be used to evaluate only the hydro projects in categories (ii) and (iii).

The other EPAs in category (iii) will not be evaluated using the interim market approach because they are part of the Biomass Energy Program. Please refer to BC Hydro's response to BCOAPO IR 2.104.1 for further description of the rationale for our approach to the Biomass Energy Program.

104.0 Reference: Exhibit B-5, BCUC 1.15.1, 1.15.2 and 1.15.2.1
BC Hydro's EPA Renewal Application (Sechelt Creek Hydro, Brown Lake Hydro, and Walden North Hydro), Exhibit B-5, BCUC 1.8.4

In response to BCUC 1.8.4 from the proceeding dealing with BC Hydro's EPA Renewal Application, BC Hydro states:

'BC Hydro's LRB shows it will not need to acquire new energy resources for many years to come. Given potential policy changes that may affect BC Hydro arising from ongoing government review and other energy related policies, on top of technology cost uncertainty in the long term, BC Hydro recently adopted the use of market price as a conservative interim assumption for evaluating energy during surplus and deficit periods.'

The response to BCUC 1.15.2.1 in the current proceeding indicates that this "conservative interim assumption" was used in the case of the two run of the river EPAs due to expire during the test period. However, the response also indicates that this "conservative interim assumption" was not adopted for facilities eligible for the Biomass Energy Program or facilities with other benefits.

2.104.3 What types of "other benefits" (per BCUC 1.15.2.1) would preclude the use of the "conservative interim assumption"?

RESPONSE:

The term "other benefits" includes safety, reliability, compliance with environmental or regulatory requirements, and benefits to First Nations and/or local communities.

BC Hydro notes that the availability of "other benefits" may not necessarily "preclude" the use of the interim market assumption for evaluating EPAs. Rather the evaluation may consider both the commercial assessment using the interim market assumption as well as the "other benefits".

105.0 Reference: Exhibit B-5, BCUC 1.17.1

2.105.1 Does the $17.3 in "cost savings" reflect just the costs attributed in the F2019 RRA to the three terminated EPAs, the one EPA that was not renewed and the cogeneration project that is not proceeding or is it also net of the opportunity value of the energy (e.g., as surplus power sales in the export market) associated with these projects?

RESPONSE:

This answer also responds to BCOAPO IR 2.105.2.

The $17.3 million reduction in forecast costs does not include a consideration of the lost value of Surplus Sales that could be associated with these projects if they had proceeded. The value of $17.3 million would be reduced to $11.7 million if we were to include a Surplus Sales value utilizing the fiscal 2019 Plan Surplus Sales value (in $/MWh) set out in line 21 of Schedule 4.0 of Appendix A of the Application.

105.0 Reference: Exhibit B-5, BCUC 1.17.1

2.105.2 If the opportunity value of the energy is not included, by how much would allowing for it reduce the "cost savings"?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.105.1 for the requested value.

106.0 Reference: Exhibit B-5, BCUC 1.21.1 and 1.21.2

2.106.1 The response indicates that the reduced availability of natural gas (due to the pipeline rupture) created the potential for increased electrical heating load due to fuel switching. However, it also notes that this potential increase was not included in the load forecast for the test period. Will this potential increase be included in the load forecast update scheduled for October 2019?

RESPONSE:

No. Please refer to BC Hydro's response to AMPC IRs 2.24.1 and 2.24.2, which describe the estimated load impacts due to the pipeline rupture.

106.0 Reference: Exhibit B-5, BCUC 1.21.1 and 1.21.2

2.106.1 The response indicates that the reduced availability of natural gas (due to the pipeline rupture) created the potential for increased electrical heating load due to fuel switching. However, it also notes that this potential increase was not included in the load forecast for the test period. Will this potential increase be included in the load forecast update scheduled for October 2019?

2.106.1.1 If not, why not?

RESPONSE:

Please refer to BC Hydro's response to AMPC IRs 2.24.1 and 2.24.2 which describe the estimated load impacts due to the pipeline rupture.

106.0 Reference: Exhibit B-5, BCUC 1.21.1 and 1.21.2

2.106.2 Will the Cost of Energy forecast be updated in conjunction with the updated load forecast?

RESPONSE:

This answer also responds to BCOAPO IR 2.106.2.1.

The October 2019 Load Forecast will not be updated for the potential impact of the pipeline rupture on the electrical heating load. Therefore, the Cost of Energy forecast will not be updated for this potential impact.

As discussed in BC Hydro's response to AMPC IR 1.1.2, BC Hydro did not observe a material impact on load due to the constrained gas supply from October 2018 to April 2019. After the immediate gas curtailment in October 2018, BC Hydro reviewed the electricity use for our largest customers that typically rely on both gas and electricity for their operations. We observed both increases and decreases in electricity consumption based on site specific factors.

106.0 Reference: Exhibit B-5, BCUC 1.21.1 and 1.21.2

2.106.2 Will the Cost of Energy forecast be updated in conjunction with the updated load forecast?

2.106.2.1 If not, why not?

RESPONSE:

Please refer to BC Hydro’s response to BCOAPO IR 2.106.2.

107.0 Reference: Exhibit B-6, BCSEA 1.14.1
Exhibit B-5, BCUC 1.15.2.1

2.107.1 For the seven expected new EPAs referenced in the response to BCSEA 1.14.1, have the agreements for each of the projects been finalized?

RESPONSE:

This response also provides BC Hydro's response to BCOAPO IRs 2.107.1.1 and 2.107.1.2.

The public version of the response to this information request has been redacted to maintain confidentiality. The un-redacted version of this response is being made available to the BCUC only, in order to protect IPPs' commercial interests. The public disclosure of the redacted information could also impact BC Hydro's commercial interests and ongoing negotiations related to the EPAs.

Since October 1, 2018, BC Hydro has executed agreements for two of the seven expected EPAs: Sukunka wind and Zonnebeke wind.

BC Hydro has not used and does not expect to use the interim market approach for the evaluation of cost-effectiveness of these seven EPAs because these projects are part of Impact Benefit Agreements with First Nations and/or are mature Standing Offer Program projects that have significant First Nations involvement. Please refer to BC Hydro's response to BCOAPO IR 2.104.1 for a description of the "other benefits" that BC Hydro may consider in the evaluation the cost-effectiveness of EPAs.

As discussed in BC Hydro's response to BCUC IR 1.15.2, for those four projects that were part of the Standing Offer Program, the price is as was provided in the Standing Offer Program Rules prior to the indefinite suspension of the program. For those EPAs not issued under the Standing Offer Program the prices [redacted]

107.0 Reference: Exhibit B-6, BCSEA 1.14.1
Exhibit B-5, BCUC 1.15.2.1

2.107.1 For the seven expected new EPAs referenced in the response to BCSEA 1.14.1, have the agreements for each of the projects been finalized?

2.107.1.1 If all of the agreements have not been finalized, what approach is being used by BC Hydro to evaluate the EPAs?

RESPONSE:

Please refer to BC Hydro’s response to BCOAPO IR 2.107.1 for a discussion on the approach BC Hydro is using for the seven expected EPAs.

107.0 Reference: Exhibit B-6, BCSEA 1.14.1
Exhibit B-5, BCUC 1.15.2.1

2.107.1 For the seven expected new EPAs referenced in the response to BCSEA 1.14.1, have the agreements for each of the projects been finalized?

2.107.1.2 If the "conservative interim assumption" described in BCUC 1.15.2.1 is not being used to evaluate the projects, please explain why.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.107.1 for a discussion on the reasons why the conservative interim assumption is not being used to evaluate these EPAs.

108.0 Reference: Exhibit B-6, CEABC 1.6.4

2.108.1 It is noted that out of the last 10 years there were four where overall purchases (market purchases and net purchases from Powerex) exceeded surplus sales. In each case, please explain why and, in particular, whether it was a function of “need” (i.e., shortfall in domestic supply) or “economics” (i.e., purchases were cheaper than available domestic supply).

RESPONSE:

BC Hydro makes net market purchases or sales on an economic basis, by optimizing the operation of system storage to maximize consolidated net revenue from operations. In general, the optimal operation depends on the relationship between system storage levels, forecast loads, inflows, and current and future market prices.

In past years when overall purchases exceeded surplus sales, BC Hydro considered it to be more economic to conduct market purchases than to use system storage in the equivalent amount.

Net purchases from Powerex are based on market economics and occur pursuant to the Transfer Pricing Agreement.

Please also refer to BC Hydro’s response to AMPC IR 1.15.4 which outlines the factors that BC Hydro considers in our optimization of the operation of system storage.

109.0 Reference: Exhibit B-6, CEC 1.16.1
Exhibit B-5, BCUC 1.24.3
Exhibit B-1, pages 4-36 to 4-37

2.109.1 Is the forecast average market price for F2020 referenced in BCUC 1.24.3 the same as the average forward price for F2020 referenced in CEC 1.16.1?

RESPONSE:

The forecast price in BC Hydro's response to BCUC IR 1.24.3 (C$40.31 per MWh for fiscal 2020) is not the same as the average forward price quoted in BC Hydro's response to CEC IR 1.16.1 ($25.84 USD per MWh for fiscal 2020, which is equivalent to C$33.10 per MWh).

The C$40.31 per MWh figure refers to a volume-weighted average value of forecast surplus sales, which were forecast to occur during specific time periods throughout fiscal 2020. The US$25.84 per MWh is an average flat market price forecast for the whole of fiscal 2020 and is not weighted based on forecast surplus sales volumes.

109.0 Reference: Exhibit B-6, CEC 1.16.1
Exhibit B-5, BCUC 1.24.3
Exhibit B-1, pages 4-36 to 4-37

2.109.1 Is the forecast average market price for F2020 referenced in BCUC 1.24.3 the same as the average forward price for F2020 referenced in CEC 1.16.1?

2.109.1.1 If not, what is the difference and why?

RESPONSE:

Please refer to BC Hydro’s response to BCOAPO IR 2.109.1 for an explanation of the difference between the two prices.

109.0 Reference: Exhibit B-6, CEC 1.16.1
Exhibit B-5, BCUC 1.24.3
Exhibit B-1, pages 4-36 to 4-37

2.109.2 What is the most recent average forward price for electricity at Mid-C for fiscal 2020, fiscal 2021, and fiscal 2022?

RESPONSE:

The average forward price as of June 2019 for electricity at Mid-C was US$31.92 per MWh for fiscal 2020, US$31.55 per MWh for fiscal 2021, and US$34.22 per MWh for 2022.

The average price for fiscal 2020 includes actual prices for April and May 2019 and forward market prices for the remainder of the fiscal year.

110.0 Reference: Exhibit B-6, CEC 1.87.1
Exhibit B-1, Appendix A, Schedule 4, Rows 8-11

2.110.1 It is noted that the market purchases currently forecast for F2019 and planned for F2020 are higher than both historic levels and planned levels for F2021. Please explain why and the extent to which this impacted the forecast/planned energy from heritage and non-heritage sources in those years.

RESPONSE:

Market Energy purchases forecast for fiscal 2019 and fiscal 2020 are higher than recent historic and planned future levels due to lower system inflows in fiscal 2019 as explained in BC Hydro’s response BCUC IR 1.24.1. In fiscal 2020, based on the October 2018 Energy Study, planned Market Energy purchases are higher due to the expected filling of system storage in that year.

Forecast Market Energy purchases act to displace generation from heritage sources and contribute directly to reducing the draft of system storage. Market Energy purchases do not appreciably displace generation from non-heritage sources since these resources are primarily must run resources and not directly impacted by system dispatch decisions.

111.0 Reference: Exhibit B-6, INCE 1.7.1
Exhibit B-5, BCUC 1.15.1

2.111.1 Which of the rows in the Table provided in INCE 1.7.1 include EPA renewals per BCUC 1.15.1?

RESPONSE:

The “Pre-2003 Electricity Purchase Agreements” row in the table provided in BC Hydro’s response to INCE IR 1.7.1 includes all of the hydro EPA renewals provided in the table in BC Hydro’s response to BCUC IR 1.15.1.

The table below sets out the specific rows in the table provided in BC Hydro’s response to INCE IR 1.7.1 that correspond to the biomass EPA renewals set out in BC Hydro’s response to BCUC IR 1.15.1.

Biomass EPA Renewals	Call Process
Armstrong Wood Waste Co-Gen	Negotiated Electricity Purchase Agreements
Celgar Green Energy	2008 Bioenergy Call – Phase 1
Howe Sound Green Energy	2010 Integrated Power Offer
NWE Williams Lake	Pre-2003 Electricity Purchase Agreements
PGP Bio Energy	2008 Bioenergy Call - Phase 1
Skookumchuck Power	Negotiated Electricity Purchase Agreements

112.0 Reference: Exhibit B-5, BCUC 1.34.3

The response states:

"Business Groups identified significant cost pressures in their respective areas during the fiscal 2020 budgeting cycle. Using the top-down, bottom-up budgeting approach these costs were not funded as the approach did not allow for costs related to these items beyond the existing budget to be funded. These costs had to be accommodated within the Business Group's existing budgets, allowing us to limit our costs increases to $8.5 million and $9.9 million in fiscal 2020 and fiscal 2021 respectively."

2.112.1 Please clarify what is meant by the "existing budgets" for each Business Group and provide a schedule that sets out the "existing budget" for each Business Group.

RESPONSE:

Existing budgets refer to the Business Groups' fiscal 2019 budgets. Fiscal 2019 budgets are the Business Groups' approved net operating cost budgets adjusted for the BCUC approved expenditures relating to the Waneta two-thirds operating costs, the Customer Crisis Fund operating costs, and budget transfers between Business Groups which net to zero across BC Hydro.

BC Hydro's existing budgets for each Business Group for fiscal 2019 are shown on the last line of the table below titled "F2019 Net Operating Cost Budget".

Fiscal 2019 ($ million)	Integrated Planning	Capital Infrastructure Project Delivery	Operations	Safety	Finance Technology and Supply Chain	People Customer and Corporate Affairs	Other	F2019 BCH Total
F2019 RRA Net Operating Cost Budget	270.1	81.9	216.2	54.9	265.0	122.5	(39.2)	971.5
Appendix A Evidentiary Update Reference	Sched 5.1, line 14	Sched 5.2, line 12	Sched 5.3, line 15	Sched 5.4, line 12	Sched 5.5, line 11	Sched 5.6, line 15	Sched 5.7, line 12 + Sched 5.0 line 8	Sched 5.0, line 15
<u>BCUC Approved Expenditures:</u>								
Waneta 2/3rd Operating Cost (BCUC Order No. G-130-18)			3.8					3.8
Customer Crisis Fund Operating Costs (BCUC Order No. G-166-17)						4.0		4.0
Budget transfers between Business Groups	9.2	1.0	(1.7)	(0.2)	(6.5)	(9.6)	7.8	0.0
F2019 Net Operating Cost Budget	279.3	82.9	218.4	54.8	258.5	116.9	(31.4)	979.3
Operating Cost Continuity Schedules	Chapter 5, Table 5A-3, line 5	Chapter 5, Table 5B-3, line 5	Chapter 5, Table 5C-3, line 6	Chapter 5, Table 5D-3, line 5	Chapter 5, Table 5E-3, line 5	Chapter 5, Table 5F-3, line 6	Chapter 5, Table 5G-3, line 6	Chapter 5, Table 5-7, line 8

112.0 Reference: Exhibit B-5, BCUC 1.34.3

The response states:

"Business Groups identified significant cost pressures in their respective areas during the fiscal 2020 budgeting cycle. Using the top-down, bottom-up budgeting approach these costs were not funded as the approach did not allow for costs related to these items beyond the existing budget to be funded. These costs had to be accommodated within the Business Group's existing budgets, allowing us to limit our costs increases to $8.5 million and $9.9 million in fiscal 2020 and fiscal 2021 respectively."

2.112.2 If cost increases for each Business Group had to be accommodated within the existing budgets, why is there any increase in F2020 and F2021?

RESPONSE:

Business Groups identified a number of cost pressures that were constrained or managed within their existing operating cost budgets. The operating cost pressures that were funded in fiscal 2020 and fiscal 2021 relate to costs for certain non-controllable cost pressures such as the Employer Health Tax.

Please refer to section 5.5.2.2 of Chapter 5 of the Application for a detailed breakdown and explanation of the non-controllable cost increases for fiscal 2020 and fiscal 2021.

113.0 Reference: Exhibit B-5, BCUC 1.35.1.1
Exhibit B-1, page 5-21, Table 5-4

2.113.1 Please explain how the $5.6 M in vacancy factor savings was calculated.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.230.7 which describes how the $5.6 million in vacancy factor savings was determined.

113.0 Reference: Exhibit B-5, BCUC 1.35.1.1
Exhibit B-1, page 5-21, Table 5-4

2.113.2 Please indicate where in Table 5-4 these savings have been included.

RESPONSE:

The vacancy factor savings are included in line 14 titled Test Period Savings in Table 5-4 of Chapter 5 of the Application. For a detailed breakdown of these savings, please refer to Table 5-6 on page 5-25 of Chapter 5 of the Application.

114.0 Reference: Exhibit B-5, BCUC 1.35.2

2.114.1 Why doesn't BC Hydro's new role as Reliability Coordinator lead to an increase in the number of positions (FTEs) required?

RESPONSE:

In BC Hydro's response to BCUC IR 1.35.2, we explained that an increase of 61 FTEs is planned in fiscal 2020 related to the Workforce Optimization Program. This includes 13 FTEs required for BC Hydro to perform the Reliability Coordination function. Further details on these FTEs are provided in BC Hydro's response to BCUC IR 1.85.5.

115.0 Reference: Exhibit B-5, BCUC 1.38.10
Exhibit B-6, BCOAPO 1.26.3

2.115.1 Is it the case that in all areas where a Work Smart initiative has led to gains in capacity hours, that there are/will be increases in workload that will "utilize" the capacity hours gained?

RESPONSE:

BC Hydro considers that full utilization of capacity hours gained through Work Smart initiatives has occurred due to increases in workload and work complexity as well as enabling employees to focus on the highest value work. For more information on the increasing complexity of BC Hydro's work and work environment, please refer to BC Hydro's response to BCUC IR 1.64.1.

115.0 Reference: Exhibit B-5, BCUC 1.38.10
Exhibit B-6, BCOAPO 1.26.3

2.115.2 Alternatively, are there not some work areas where the capacity hours gained will exceed the workload increases in F2020 and F2021 such that there could be a need for fewer FTEs? If not, why not?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.115.1, where we note that BC Hydro considers that full utilization of capacity hours gained through Work Smart initiatives has occurred due to increases in workload and work complexity as well as enabling employees to focus on the highest value work.

Please also refer to BC Hydro's response to BCOAPO IR 1.26.3, where we note that Work Smart's objective is to deliver capacity hours gained, as opposed to reducing FTEs. As noted on page 5-17 of Chapter 5 of the Application, the Work Smart program seeks to address workload issues (e.g., the ability to manage growing workload), so that new costs can be avoided. Work Smart is thus one approach BC Hydro is using to limit its base operating cost increases over the test period. In BC Hydro's response to BCUC IR 1.38.11, we note that without the capacity hours gained through the Work Smart program, BC Hydro's operating costs (and thus its revenue requirements) would be higher.

116.0 Reference: Exhibit B-5, BCUC 1.38.13

2.116.1 What are the estimated capacity gains in F2020 from the initiatives noted in the response?

RESPONSE:

Please refer to BC Hydro’s response to BCUC IR 1.38.3, which describes the method used to estimate the incremental capacity hours to be gained in fiscal 2020 of approximately 22,800 hours.

116.0 Reference: Exhibit B-5, BCUC 1.38.13

2.116.2 Please explain how initiatives #2 and #3 will lead to gains in capacity hours.

RESPONSE:

Initiatives two (Storm Response Customer Experience) and three (Storm Response Customer Call Handling) focus on improving the timeliness and accuracy of information to our customers during storm events through enhancements to communication methods such as:

- **The online outage map;**
- **Online and social media messages;**
- **Text messaging; and**
- **The interactive voice response to our call centre.**

By doing these initiatives, we anticipate the number of calls to our call centre will decline during storm events. Fewer calls will result in capacity hours gained, leading to faster answering of calls and less waiting time for our customers. However, the amount of capacity hours gained cannot be reliably measured until this initiative is implemented.

117.0 Reference: Exhibit B-5, BCUC 1.42.7

2.117.1 What does the bargaining mandate established by the Public Sector Employers' Council for provincial public sector employers, including BC Hydro, represent (i.e., is it guide for public sector employers, is it a maximum, or does it represent something else)?

RESPONSE:

The bargaining mandate established by the Government of B.C. provides the contract term and maximum general wage increase that can be provided by the employer in union collective bargaining. The current mandate, which applies from April 1, 2019 to March 31, 2022 at BC Hydro, requires a three year contract term with maximum annual general wage increases of 2 per cent for union employees.

118.0 Reference: Exhibit B-5, BCUC 1.43.5 and 1.103.1
Exhibit B-1, pages 5-25 & 8-30

2.118.1 Please provide the overall impact on BC Hydro's revenue requirements for F2020 and F2021 of implementing IFRS 16 separating out the impact associated with EPA and non-EPA leases. Please set out the impact by expense item (i.e., depreciation, OM&A, finance charges, etc.).

RESPONSE:

The overall impacts on BC Hydro's revenue requirements for fiscal 2020 and fiscal 2021 of implementing IFRS 16 as reflected in the Evidentiary Update are shown in the schedule below. Amounts in brackets represent decreases in expenses and amounts without brackets represent increases in expenses.

($ million)	EPA Impacts		Non-EPA Impacts		Total Impacts	
	F2020	F2021	F2020	F2021	F2020	F2021
IAS 17 (Previous Standard reversal)						
Operating expense	(54.5)	(55.1)	(3.9)	(3.9)	(58.4)	(59.0)
Grants and taxes	(2.5)	(2.6)			(2.5)	(2.6)
Depreciation	(22.8)	(22.8)			(22.8)	(22.8)
Finance Charges	(41.7)	(40.8)			(41.7)	(40.8)
Cost of energy	(132.8)	(134.8)			(132.8)	(134.8)
Total	**(254.3)**	**(256.1)**	**(3.9)**	**(3.9)**	**(258.2)**	**(260.0)**
IFRS 16						
Depreciation	88.9	90.1	3.1	3.2	92.0	93.3
Finance Charges	48.4	46.1	1.0	1.0	49.4	47.1
Cost of energy	117.9	119.5			117.9	119.5
Total	**255.2**	**255.6**	**4.1**	**4.2**	**259.3**	**259.8**
Net Change						
Operating expense	(54.5)	(55.1)	(3.9)	(3.9)	(58.4)	(59.0)
Grants and taxes	(2.5)	(2.6)	-	-	(2.5)	(2.6)
Depreciation	66.1	67.3	3.1	3.2	69.2	70.5
Finance Charges	6.7	5.3	1.0	1.0	7.7	6.3
Cost of energy	(14.9)	(15.4)	-	-	(14.9)	(15.4)
Impact before amortization of regulatory transfer to NHDA at adoption	**1.0**	**(0.5)**	**0.2**	**0.3**	**1.2**	**(0.2)**
Amortization of amount deferred to NHDA (adoption impact deferred)	41.5	23.3			41.5	23.3
Impact on Revenue Requirement	**42.5**	**22.8**	**0.2**	**0.3**	**42.7**	**23.1**

The amortization of the "Amortization of the amount deferred to the NHDA" is prorated based on the amortization of the total balance in the Non-Heritage Deferral Account included in the Evidentiary Update.

119.0 Reference: Exhibit B-5, BCUC 1.49.3
Exhibit B-1, page 5-41 (Table 5-1)

2.119.1 Please confirm that the $0.8 M in savings associated with Field Service Representatives (i.e., manual metering reading) is not attributable to the full Accenture repatriation as these services were repatriated in F2018.

RESPONSE:

Table 5-11 (page 5-41 of Chapter 5) of the Application provides a complete view of operating savings associated with repatriating all functions from Accenture during the fiscal 2017 to fiscal 2019 period.

Savings associated with Field Service Representatives are not included in the $1.2 million of incremental savings in fiscal 2020 as shown in Figure 5-5 on page 5-22 or Table 5-6 on page 5-25 of Chapter 5 of the Application because they had been realized prior to the fiscal 2020 to fiscal 2021 Test Period.

120.0 Reference: Exhibit B-5, BCUC 1.51.1

2.120.1 Do all graduating apprentices replace employees that are either retiring/leaving the Corporation?

RESPONSE:

The majority of graduating apprentices replace employees that are either retiring/leaving BC Hydro. Some apprentices leave BC Hydro for other opportunities. Apprentices start applying on bulletined postings six months before graduation. If there are no bulletined postings at the time, they are categorized as "journeyperson in holding" and continue to actively support operational crews until they are successful in securing a permanent journeyperson role.

120.0 Reference: Exhibit B-5, BCUC 1.51.1

2.120.1 Do all graduating apprentices replace employees that are either retiring/leaving the Corporation?

2.120.1.1 If not, please explain how trainees graduating from the program lead to a reduction in overall FTEs.

RESPONSE:

As discussed in BC Hydro’s response to BCUC IR 1.51.1, the reduction in Apprentice and Trainees will be achieved through both graduations and fewer new hires. The reduction in new hires leads to a reduction in overall FTEs.

Please also refer to BC Hydro’s response to BCOAPO IR 2.120.1 where we explain that the majority of trainee graduates from the program replace employees that are either retiring/leaving BC Hydro.

121.0 Reference: Exhibit B-6, AMC 1.3.1 and 1.3.2

2.121.1 With respect to the table provided in response to AMC 1.3.2, please include a column with the F2019 RRA FTEs.

RESPONSE:

Please refer to BC Hydro’s response to BCUC IR 2.222.7 which provides an updated table including the fiscal 2019 RRA FTEs as requested in the question.

The financial information provided in the response has been updated based on the information in BC Hydro’s Evidentiary Update.

121.0 Reference: Exhibit B-6, AMC 1.3.1 and 1.3.2

2.121.2 With respect to the table provided in response to AMC 1.3.2, why is there no line showing the impact of the Workforce Optimization program?

RESPONSE:

The FTE's related to the Workforce Optimization program are included in the Operating, Capital and Deferred lines in the table provided in BC Hydro's response to AMPC IR 1.3.2.

For a breakdown of the Workforce Optimization program planned FTE's by Business Group and function, please refer to BC Hydro's response to BCOAPO IR 1.29.1 and BCUC IR 1.48.3.

121.0 Reference: Exhibit B-6, AMC 1.3.1 and 1.3.2

2.121.3 What is the reason for increase in Operating FTEs in F2018 and why did the number decline in F2019?

RESPONSE:

In reference to the table provided in BC Hydro's response to AMPC IR 1.3.2, BC Hydro notes, operating FTEs increase by 127 from fiscal 2017 actuals to fiscal 2018 actuals, followed by a decrease of 158 from fiscal 2018 actuals to fiscal 2019 forecast.

The operating FTE increase of 127 from fiscal 2017 actuals to fiscal 2018 actuals is primarily due to FTE additions resulting from the Workforce Optimization Program.

The operating FTE decrease of 158 from fiscal 2018 actuals to fiscal 2019 forecast is primarily due to a shift from internal to external resources assigned to deliver the maintenance work programs (FTE actual/forecast for the maintenance work programs are reflected in the Operating FTE line in the table provided in BC Hydro's response to AMPC IR 1.3.2).

As described in section 5C.4.1 of Chapter 5C of the Application, each fiscal year the maintenance work programs are assigned to internal and external resources to deliver the work. As the work assigned takes into consideration the resource availability and skillsets required to deliver the maintenance work programs planned for the year, there can be fluctuations in the assignment to internal and external resources.

122.0 Reference: Exhibit B-6, AMC 1.3.12

2.122.1 Is there any true-up (or regulatory account) that addresses/accounts for the difference between forecast and actual project write-offs?

RESPONSE:

No, there are no true-ups or regulatory accounts that capture differences between forecast and actual project write-offs. Variances between forecast and actual project write-offs are to the account of the shareholder.

122.0 Reference: Exhibit B-6, AMC 1.3.12

2.122.1 Is there any true-up (or regulatory account) that addresses/accounts for the difference between forecast and actual project write-offs?

2.122.1.1 If not, would a regulatory account to address such differences be appropriate?

RESPONSE:

A regulatory account would result in ratepayers paying for the actual costs of write-offs. A regulatory account would protect ratepayers from paying higher costs than actuals in the event that BC Hydro incurred lower actual write-offs than forecast. A regulatory account would protect the shareholder from receiving less net income in the event that BC Hydro incurred higher actual write-offs than forecast.

BC Hydro has not requested a regulatory account at this time and will monitor write-off variances relative to the new forecasting methodology outlined in section 8.11 of Chapter 8 of the Application and using the criteria discussed in section 7.6 of Chapter 7 of the Application when considering whether to request the establishment of a new regulatory account.

123.0 Reference: Exhibit B-5, BCUC 1.54.3
Exhibit B-6, BCOAPO 1.7.1

2.123.1 In making its decision not to prepare USoA financial schedules did BC Hydro consider the value of such schedules in benchmarking exercises such as one performed by the Brattle Group?

RESPONSE:

As discussed in BC Hydro's response to BCUC IR 1.54.3, BC Hydro stopped preparing the BCUC Annual Report under the Uniform System of Accounts (USoA) framework following a discussion with BCUC staff on May 2, 2017 where we indicated that the USoA framework was costly to produce, of limited use and value, and only provided for BCUC compliance purposes. At the time, BC Hydro was not aware that that these schedules could be helpful for benchmarking analysis such as the benchmarking study prepared by The Brattle Group.

In the Application, BC Hydro has requested that the BCUC reconsider and rescind Directive 57 of its Decision on BC Hydro's Fiscal 2009 to Fiscal 2010 Revenue Requirements Application which directs that BC Hydro revenue requirement applications contain financial information that follows the USoA framework.

Rescinding Directive 57 would not prevent BC Hydro from preparing USoA financial schedules in the future, if those schedules were required for additional benchmarking analysis. Rather, it would provide BC Hydro management with the discretion to determine whether and how often to prepare these schedules.

Preparing the USoA financial schedules is labour intensive and would create additional cost pressures. In BC Hydro's view, having the discretion to prioritize these pressures against other requirements is an important part of our ongoing efforts to limit overall base operating cost increases.

123.0 Reference: Exhibit B-5, BCUC 1.54.3
Exhibit B-6, BCOAPO 1.7.1

2.123.2 Please explain why BC Hydro considered it appropriate to discontinue preparing USoA financial schedules without the formal approval of the BCUC.

RESPONSE:

In the cover letter to BC Hydro's Fiscal 2017 Annual Financial Report to the BCUC, BC Hydro stated:

> **"BC Hydro and the Commission staff have been working together to review the content of the Annual Financial Report to the Commission to improve and reflect a more relevant and informative report. Based on the dialogue between both parties BC Hydro is providing an annual report for fiscal 2017 with agreed upon changes, including some deletions of sections previously reported that are considered either redundant or not applicable to BC Hydro."**

The cover letter provided a table that indicated as a result of this review, section 15.2, Uniform System of Accounts (USoA) financial schedules, had been removed.

In the Application, BC Hydro has requested that the BCUC reconsider and rescind Directive 57 of its Decision on BC Hydro's Fiscal 2009 to Fiscal 2010 Revenue Requirements Application. For further discussion on this request, please refer to BC Hydro's response to BCOAPO IR 2.123.1.

124.0 Reference: Exhibit B-6, BCOAPO 1.32.1

2.124.1 The response suggests that the Unallocated Funds budget from the F2009 RRA was $8 M (i.e. $15 M less $7 M). Please provide a reference to the previous RRA that demonstrates this is the case.

RESPONSE:

BC Hydro interprets the question to be referring to fiscal 2019 RRA plan (not fiscal 2009).

The unallocated funds budget for fiscal 2019 RRA plan was $6.5 million.

Please refer to BC Hydro's response to BCUC IR 1.63.5 where we provide responses to information requests from the Previous Application proceeding which describe the unallocated funds budget and its amount for fiscal 2015 to fiscal 2019.

124.0 Reference: Exhibit B-6, BCOAPO 1.32.1

2.124.1 The response suggests that the Unallocated Funds budget from the F2009 RRA was $8 M (i.e. $15 M less $7 M). Please provide a reference to the previous RRA that demonstrates this is the case.

2.124.1.1 If this premise is not correct, please explain why and clarify the response to BCOAPO 1.32.1.

RESPONSE:

The premise to this question is not correct as the $7.0 million of Accenture Repatriation savings achieved prior to the test period is one annual planning adjustment made during the fiscal 2019 budgeting process. BC Hydro's response to BCUC IR 2.231.7 provides details of how the annual planning adjustments were determined.

As shown in BC Hydro's response to BCUC IR 2.231.6, the total Annual Planning Adjustments made to the fiscal 2019 unallocated funds budget was $8.5 million and the fiscal 2019 RRA plan amount was $6.5 million.

125.0 Reference: Exhibit B-6, BCOAPO 1.34.1

The response states:

"BC Hydro's maintenance work is planned, on a prioritized basis, within the approved maintenance budget level. Reallocations may be made among the various categories of maintenance (preventative, condition-based, corrective, facilities or engineering) or across the Stations Asset Maintenance and Line Asset Maintenance departments based on maintenance priorities. In the event that there are significant unforeseen risks or events which cannot be accommodated in the existing maintenance budget a request would be made to reallocate funds from elsewhere in BC Hydro".

2.125.1 For each department, what was the initial "approved maintenance budget level" for F2020 and what was it based on?

RESPONSE:

The approved maintenance budget level for Line Asset Maintenance and Stations Asset Maintenance is contained in Table 5-17 of Chapter 5 of the Application and is provided below for ease of reference:

	Fiscal 2020 Plan ($ million)
Line Asset Maintenance	**105.2**
Stations Asset Maintenance	**85.4**

The approved maintenance budgets were based on three factors:

- **A review of historic planned and actual spending levels;**
- **Changes (improvements or degradation) in asset condition and system performance, as indicated by asset health ratings and performance measures; and**
- **The amount of new assets added to the system less any asset retirements.**

For further information on the increase in maintenance funding from fiscal 2019 to fiscal 2020, please refer to BC Hydro's response to BCUC IR 2.233.1.

125.0 Reference: Exhibit B-6, BCOAPO 1.34.1

The response states:

"BC Hydro's maintenance work is planned, on a prioritized basis, within the approved maintenance budget level. Reallocations may be made among the various categories of maintenance (preventative, condition-based, corrective, facilities or engineering) or across the Stations Asset Maintenance and Line Asset Maintenance departments based on maintenance priorities. In the event that there are significant unforeseen risks or events which cannot be accommodated in the existing maintenance budget a request would be made to reallocate funds from elsewhere in BC Hydro".

2.125.2 Were there any "reallocations" between departments based on "maintenance priorities"? If so, what are they and why were they required?

RESPONSE:

No reallocation of the existing maintenance budgets was made in preparing the maintenance forecasts for the test period.

In the future, reallocations may take place within the fiscal year, in response to emerging issues, and to manage within the overall maintenance budget.

125.0 Reference: Exhibit B-6, BCOAPO 1.34.1

The response states:

"BC Hydro's maintenance work is planned, on a prioritized basis, within the approved maintenance budget level. Reallocations may be made among the various categories of maintenance (preventative, condition-based, corrective, facilities or engineering) or across the Stations Asset Maintenance and Line Asset Maintenance departments based on maintenance priorities. In the event that there are significant unforeseen risks or events which cannot be accommodated in the existing maintenance budget a request would be made to reallocate funds from elsewhere in BC Hydro".

2.125.3 Was there any reallocation of funds from elsewhere in BC Hydro? If so, how much was reallocated, to which departments was it directed and what necessitated the need for the reallocation?

RESPONSE:

As discussed in section 5.8.1 of Chapter 5 of the Application, $7.9 million was re-purposed from BC Hydro's unallocated funds budget to enable additional maintenance work to be proactively planned and delivered.

A further $3.5 million was transferred to the Integrated Planning Business Group as part of a re-organization. This cost of this re-organization was net neutral to BC Hydro.

Table 5-18 of Chapter 5 provides a summary of these transfers; however, the version in the Application contained incorrect values for Standard Labour Rate increases. The table below provides a corrected version.

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	0	0	11.1	11.1
Standard Labour Rate Increases	1.3*	2.5*	0.8	4.6
Net Re-organization impacts**	0.3	3.2	0	3.5
Re-purposing of unallocated funds	3.1	4.7	0	7.9
Total	4.7	10.3	11.9	27.0

* corrected values

** offset by equivalent reductions to the Business Unit Support KBU of the Operations Business Group and the Engineering KBU of the Integrated Planning Business Group

Within Stations Asset Maintenance, $4.6 million of the additional $4.7 million of funding re-purposed from the unallocated funds budget was allocated for additional substation maintenance, based on actual historical spending levels and identified maintenance needs. For further information on the maintenance work funded through this reallocation, please refer to BC Hydro's response to BCUC IR 2.233.1.

Within Line Asset Maintenance, the $3.1 million of funding re-purposed from the allocated funds budget was allocated for:

- **A $1.0 million increase for telecom protection & control maintenance, primarily related to NERC CIP v5 ($0.5 million) and additional preventative maintenance ($0.5 million);**
- **A $1.0 million increase for transmission line maintenance, primarily related to new circuits added to the power system; and**
- **A $1.1 million increase for distribution line maintenance, primarily related to addressing high risk defects on the system including end of life crossarms and overhead line automatic splice replacements.**

126.0 Reference: Exhibit B-5, BCUC 1.69.3

The explanation for the actual F2017 Business Support costs being higher than the F2017 RRA value is that "$11.0 million planned savings from the Transmission, Distribution and Customer Service Efficiency Initiative. The planned savings were held in the Business Unit Support KBU and were not allocated to the individual KBUs; however, the actual savings were achieved in the individual KBUs." Similar observations apply for F2018 (actual) and F2019 (forecast). Please explain why there is no overall (equivalent) reduction in the actual (vs. plan) costs for the other KBUs in these years.

2.126.1 What were the actual savings achieved in each of F2017, F2018 and F2019?

RESPONSE:

The savings for fiscal 2017 to fiscal 2019 were $19.0 million per year and were permanently removed from the KBU operating budgets in the previous test period.

Attachment 1 to this response provides BC Hydro's response to BCOAPO IR 2.75.1 from the Previous Application proceeding which provides a breakdown of the specific KBU budget reductions.

British Columbia Old Age Pensioners' Organization Information Request No. **2.75.1** Dated: **December 16, 2016** British Columbia Hydro & Power Authority Response issued **January 23, 2017**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2017 – Fiscal 2019 Revenue Requirements Application**	**Exhibit:** **B-15**

75.0 Reference: BCUC 1.50.3; 1.50.3.1 and 1.51.2

2.75.1 The response to BCUC 1.50.3 indicates that $19 M in savings was allocated to individual business units. However, the change in the Business Unit Support costs is only $15.7 M (i.e. $6.8 M + $8.9 M). Please reconcile.

RESPONSE:

The change in Business Unit Support reflects an increase of $15.7 million only as $3.3 million of the $19.0 million savings result from cost reductions achieved in the Business Unit Support key business unit.

Please see the table provided below for a reconciliation of fiscal 2017:

Transmission, Distribution and Customer Services Operating

Costs Before Regulatory Account Transfers by Key Business Unit

	($ million)	F2017 RRA Plan	SBU Adj	Savings	F2017 Recast
		5			5
1	Field & Grid Operations	146.4	-	(1.3)	145.2
2	Asset Management & Distribution Engineering	168.9	-	(6.4)	162.5
3	Program & Contract Management	12.9	-	(0.5)	12.4
4	Customer Service & Distribution Design	88.0	-	(3.0)	85.1
5	Technology	139.5	-	(4.6)	134.9
6	Business Unit Support	(8.9)	19.0	(3.3)	6.8
7	Total	546.8	19.0	(19.0)	546.8

126.0 Reference: Exhibit B-5, BCUC 1.69.3

The explanation for the actual F2017 Business Support costs being higher than the F2017 RRA value is that "$11.0 million planned savings from the Transmission, Distribution and Customer Service Efficiency Initiative. The planned savings were held in the Business Unit Support KBU and were not allocated to the individual KBUs; however, the actual savings were achieved in the individual KBUs." Similar observations apply for F2018 (actual) and F2019 (forecast). Please explain why there is no overall (equivalent) reduction in the actual (vs. plan) costs for the other KBUs in these years.

2.126.2 Based on the response to BCUC 1.69.3, one would expect to see the annual total actual/currently forecast costs for the other departments to be less than the RRA values in each of the years F2017-F2019 based on achieved savings. However, this is not the case. Please explain why.

RESPONSE:

As shown in Attachment 1 to BC Hydro's response to BCOAPO IR 2.126.1, $19.0 million in annual savings were achieved through the Transmission, Distribution and Customer Service Efficiency Initiative within the KBUs of the former Transmission, Distribution and Customer Services Business Group.

Based on BC Hydro's re-organization to the Plan-Build-Operate-Support Model, $9.7 million in savings was attributed to the Integrated Planning Business Group.

While KBU operating budgets within the Integrated Planning Business Group were reduced to reflect these savings, BC Hydro's Executive Team also approved funding reallocations to the Integrated Planning Business Group to perform additional maintenance work, resulting in higher actuals.

For additional information regarding the approved funding reallocation process, please refer to BC Hydro's response to BCUC IR 1.36.2.1.

127.0 Reference: Exhibit B-6, BCOAPO 1.42.2

2.127.1 The forecast spending on Generation Station Maintenance increases by 10% in F2020 (over F2019 Forecast). What are the specific reasons for the increase?

RESPONSE:

The increase in forecast spending on Generation Station Maintenance from fiscal 2019 forecast to fiscal 2020 plan is almost entirely due to Standard Labour Rate Increases ($1.8 million) and Re-organization impacts ($3.2 million). The Re-organization impacts do not represent new work – they are simply re-categorized costs and are offset by reductions to the Business Unit Support KBU of the Operations Business Group and the Engineering KBU of the Integrated Planning Business Group. For further information, please refer to BC Hydro's response to BCUC IR 2.233.1.

127.0 Reference: Exhibit B-6, BCOAPO 1.42.2

2.127.2 Why is a similar level of spending on Generation Station Maintenance required in F2021?

RESPONSE:

BC Hydro believes that the level of maintenance spending in fiscal 2020 and fiscal 2021 is appropriate. Preventative maintenance spending levels are based on the number of assets which are not expected to decrease from fiscal 2020 to fiscal 2021. Condition based and corrective maintenance spending levels are based on the number of assets as well as the age and use of those assets, which is also expected to remain consistent from fiscal 2020 to fiscal 2021. Generation Station Maintenance cost increases from fiscal 2020 to fiscal 2021 are primarily due to Standard Labour Rate increases.

127.0 Reference: Exhibit B-6, BCOAPO 1.42.2

2.127.3 The forecast spending on Substations Maintenance increases by 30% in F2020 (over F2019 Forecast). What are the specific reasons for the increase?

RESPONSE:

The increase in forecast spending on Substations Maintenance from fiscal 2019 forecast to fiscal 2020 plan is primarily due to additional planned preventative, condition-based and corrective maintenance work in BC Hydro's substations. For further information, please refer to BC Hydro's response to BCUC IR 2.233.1.

127.0 Reference: Exhibit B-6, BCOAPO 1.42.2

2.127.4 Why is a similar level of spending on Substations Maintenance required in F2021?

RESPONSE:

BC Hydro's substation maintenance budgets have been under pressure in previous years due to an aging asset base and new assets coming into service. As discussed in our response to BCUC IR 2.233.1, BC Hydro is increasing spending on substation assets in fiscal 2020 to bring investments to an appropriate level. These asset characteristics and associated maintenance requirements are expected to continue into fiscal 2021. Substations maintenance cost increases in fiscal 2021 are primarily due to Standard Labour Rate increases.

128.0 Reference: Exhibit B-5, BCUC 1.85.3
BC Hydro's MRS RC Registration Application, Exhibit B-1, page 2-4

2.128.1 BC Hydro's MRS RC Registration Filing indicates that BC Hydro's PEAK membership fees are in the order of $4 M annually. Which KBU's budget for F2019 includes these membership fees?

RESPONSE:

The budget for PEAK membership fees for fiscal 2019 is in the Inter-utility Operations Department of the T&D System Operations KBU.

128.0 Reference: Exhibit B-5, BCUC 1.85.3
BC Hydro's MRS RC Registration Application, Exhibit B-1, page 2-4

2.128.2 Please demonstrate that the KBU's budget for F2020 has been reduced to reflect the fact BC Hydro will no longer be required to pay these membership fees.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.241.1 which describes the budget for PEAK membership fees for the test period.

129.0 Reference: Exhibit B-6, CEC 1.52.1 to 1.52.5

2.129.1 How does BC Hydro measure the performance of its Revenue Assurance Program?

RESPONSE:

As described on page 5F-31 in section 5F.5.2.2 of Chapter 5F of the Application, the primary objective of the Revenue Assurance program is to deter a return to previous levels of electricity theft and sustain the theft reduction benefits associated with the Smart Metering Infrastructure (SMI) program.

In fiscal 2019, only 1 per cent of grow-ops encountered in the course of Revenue Assurance investigations were found to be engaged in theft of electricity. As outlined in the SMI Project Completion report, preventing theft of electricity increases paid revenue and reduces long-run energy costs for all customers.

The table below outlines key operational metrics for the past three fiscal years.

Revenue Assurance Performance	Fiscal 2017	Fiscal 2018	Fiscal 2019
Number of Investigations	2,036	2,934	2,982
Number of Thefts Confirmed	95	112	119
Number of Metering and Billing Errors Rectified	37	85	194
Number of Overloaded Services Made Safe	27	125	292

129.0 Reference: Exhibit B-6, CEC 1.52.1 to 1.52.5

2.129.2 What has been the program's performance for the last 3 years?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.129.1 where we outline key operational metrics for the Revenue Assurance program for the last three years.

129.0 Reference: Exhibit B-6, CEC 1.52.1 to 1.52.5

2.129.3 With respect to CEC 1.52.3, what was the total amount recovered in each of F2017, F2018 and F2019 that is directly attributable to the Revenue Assurance Program? Please report separately recoveries related to grow-ops versus other thefts.

RESPONSE:

As discussed in BC Hydro’s response to BCOAPO IR 2.129.1, recoveries from back-billing are not the primary benefit of the Revenue Assurance program. Rather, the objective is to prevent a return to wide-spread theft of electricity and sustain the revenue and cost of energy benefits associated with the Smart Metering Infrastructure program.

The table below provides the total amount of revenue recovered as a direct result of the Revenue Assurance program. Revenue recovered from back-billing of thefts has been broken down between grow-op and non-grow-op thefts. This table also includes revenue collected as a result of metering and billing errors identified through the Revenue Assurance program.

Revenue Assurance Recoveries ($)	Fiscal 2017	Fiscal 2018	Fiscal 2019
Grow-op Thefts	317,119	350,633	144,008
Non-Grow-op Thefts	143,301	20,131	37,092
Total Thefts Payments Received	460,420	370,765	181,100
Metering and Billing Errors	387,590	427,991	500,614
Total Revenue Recovered	848,010	798,756	681,714

129.0 Reference: Exhibit B-6, CEC 1.52.1 to 1.52.5

2.129.4 For each of the years F2017-F2019, what was the total cost of the Revenue Assurance Program?

RESPONSE:

The table below provides the costs of the Revenue Assurance program for fiscal 2017 to fiscal 2019.

Revenue Assurance Costs ($ 000)	Fiscal 2017	Fiscal 2018	Fiscal 2019
Revenue Assurance Team	**2,284.8**	**2,037.1**	**2,295.5**
Field Investigation Team	**4,560.0**	**4,778.4**	**5,050.3**
Total	**6,844.8**	**6,815.5**	**7,345.8**

129.0 Reference: Exhibit B-6, CEC 1.52.1 to 1.52.5

2.129.5 With respect to CEC 1.52.4, what is the basis for the 5% and 60% figures?

RESPONSE:

These figures are calculated based on the outcomes of those revenue assurance field investigations each year wherein the presence of a grow-op was confirmed. The percentage figures reflect the number of thefts involving marijuana grow-ops divided by the total number of concluded investigations wherein the presence of a grow-op was confirmed (including those grow-ops where all electricity was metered).

As shown in the table, 62 per cent of revenue assurance field investigations in fiscal 2011 found theft from marijuana grow-ops. This reduced to 1 per cent in fiscal 2019.

Revenue Assurance Field Investigation Outcomes		Fiscal 2011	Fiscal 2019
Number of Grow-op Related Thefts Confirmed	A	503	8
Number of Revenue Assurance Investigations Involving Grow-ops	B	805	1,474
% of Grow-ops Found to be Engaged in Theft of Electricity	C = A/B	62%	1%

130.0 Reference: Exhibit B-5, BCUC 1.107.1

2.130.1 For each project with a positive variance of 10% or more, please explain why actual costs were higher than expected costs.

RESPONSE:

Please refer to BC Hydro's response to AMPC IR 2.36.2 which provides variance explanations for projects placed in-service from March 1, 2018 to March 31, 2019 with an Expected Cost of $5 million or greater and a cost variance greater than 5 per cent.

131.0 Reference: Exhibit B-5, BCUC 1.110.1
Exhibit B-1, Appendix H, page 15

The response states in part:

"During the annual capital planning cycle in 2018 to develop the fiscal 2020 to fiscal 2024 Capital Plan, any ex-plan projects already approved and not reflected in the prior capital plan (i.e., the capital plan developed in 2017) were incorporated into the capital plan. Based on updated information for all projects within the capital plan including these ex-plan projects, the prioritization process was used to reduce the fiscal 2020 to fiscal 2024 Capital Plan to the previously approved targets for that period.

2.131.1 Please provide a schedule that sets out: i) the previously approved targets for the period and ii) the forecast capital spending based on updated information for all projects within the capital plan including the ex-plan projects prior to the use of the prioritization process to reduce the F2020 to F2024 Capital Plan to the previously approved targets for the period.

RESPONSE:

BC Hydro assumes that the period referred to in the question is fiscal 2020 to fiscal 2024. As discussed in sections 6.3.2 and 6.3.3 of Chapter 6 of the Application, preliminary financial targets are developed for each of the asset categories considering the factors used during top down planning, as well as the historical composition of the capital plan. These targets are established as capital additions per fiscal year. Therefore, the amounts included in the table below are stated as annual capital additions (excluding Site C and Waneta).

Capital additions are used for prioritization within the enterprise capital planning process because they have a direct impact on BC Hydro's revenue requirements.

$ Million	Fiscal 2020	Fiscal 2021	Fiscal 2022	Fiscal 2023	Fiscal 2024
Capital Planning Additions Targets	1,217	1,282	1,256	1,394	1,666
Pre-Prioritization Capital Additions Forecast	1,332	1,116	1,670	1,551	1,681

131.0 Reference: Exhibit B-5, BCUC 1.110.1
Exhibit B-1, Appendix H, page 15

The response states in part:

"During the annual capital planning cycle in 2018 to develop the fiscal 2020 to fiscal 2024 Capital Plan, any ex-plan projects already approved and not reflected in the prior capital plan (i.e., the capital plan developed in 2017) were incorporated into the capital plan. Based on updated information for all projects within the capital plan including these ex-plan projects, the prioritization process was used to reduce the fiscal 2020 to fiscal 2024 Capital Plan to the previously approved targets for that period.

2.131.2 Please indicate which projects were impacted by the prioritization process and why the prioritization process deemed that it was appropriate to have their spending for the period reduced/eliminated versus the spending on other projects?

RESPONSE:

This answer also responds to BCOAPO IR 2.131.3.

The table below was originally provided in BC Hydro's response to BCUC IR 1.108.1.2, and includes the reason each investment was deferred or cancelled. The table has been updated to include the risk score associated with investments deferred during the development of the Fiscal 2020 to Fiscal 2024 Capital Plan. The risk scores for these projects will be updated as necessary, as planning activities progress for the fiscal 2021 to fiscal 2030 period.

Project Name	Reason for Deferral / Cancellation	Operational Impact	Risk Score
Fraser Valley West Area Reinforcement: Phase 2 (formerly Fraser Valley West Substation Expansion)	Expected Change in Load Forecast	None anticipated	10.5*
Metro North Transmission (MNT)	Expected Change in Load Forecast	None anticipated	11.0*
Yaletown (DGR) Property Purchase	Expected Change in Load Forecast	None anticipated	10.0*
Hundred Mile House – Spences Bridge	Expected Change in Load Forecast	None anticipated	9.0*

Project Name	Reason for Deferral / Cancellation	Operational Impact	Risk Score
Capilano Substation 25 kV Conversion	**Expected Change in Load Forecast**	**None anticipated**	**10.5***
VI-GUL-005 SAL 25F61 Submarine Cable Extension to North Pender Island	**Review of the cost-benefit and further study of the system risks is required to justify the timing of the project scope**	**None anticipated**	**8.5**
LM-VAN-088 DV - West End Voltage Conversion Preparation for DGR 12F86 and 87	**Extension of schedules for all Downtown Vancouver/West End voltage conversions to align with changes in the timing of new substations**	**None anticipated**	**8.5**
LaJoie - Governor/Pressure Regulating Valve Replacement	**Adjusted project timing based on the balance of system performance, risk and affordability**	**Accepted potential for increased maintenance and requirement to staff the station during line outages due to control issues of the governor**	**9.5**
MCA - Replace Units 1 to 4 Cooling Water Piping	**Adjusted project timing based on the balance of system performance, risk and affordability**	**Accepted potential for additional maintenance to repair pipe leaks until risks addressed**	**9.0**
PCN - Flood Discharge Gates Reliability Improvement	**Project cancelled at conclusion of Definition Phase due to insufficient risk reductions to justify costs. Review of the delivery and procurement models for project scope is required. Need is expected to be addressed under future projects later in the planning horizon.**	**None anticipated. Project initiation was advanced in efforts to gain synergies with a similar project at WAC Bennett Dam, which were not realized**	**11.0**
Revelstoke - U1 - U4 Service Water Piping Replacement	**Highest risk items addressed through targeted small capital investments. Deferred pending condition assessment update of remaining items.**	**Accepted potential for additional maintenance to repair pipe leaks until risks addressed**	**8.5**

*** The risk scores for these five projects were not updated following the prioritization of the Fiscal 2019 to Fiscal 2028 Capital Plan because they were no longer required in the fiscal 2020 to fiscal 2024 period given the expected change in load forecast. The risk scores for these five projects were based on the May 2016 System Peak Demand Load Forecast and the 2017 Substation Peak Demand Forecast.**

131.0 Reference: Exhibit B-5, BCUC 1.110.1
Exhibit B-1, Appendix H, page 15

The response states in part:

"During the annual capital planning cycle in 2018 to develop the fiscal 2020 to fiscal 2024 Capital Plan, any ex-plan projects already approved and not reflected in the prior capital plan (i.e., the capital plan developed in 2017) were incorporated into the capital plan. Based on updated information for all projects within the capital plan including these ex-plan projects, the prioritization process was used to reduce the fiscal 2020 to fiscal 2024 Capital Plan to the previously approved targets for that period.

2.131.3 For those projects that were impacted by the prioritization process, please indicate what their risk scores are per Exhibit B-1, Appendix H, page 15.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.131.2.

132.0 Reference: Exhibit B-5, BCUC 1.110.1

The response states in part:

"Three ex-plan projects related to transmission system upgrades for the Liquefied Natural Gas and Oil and Gas sectors in the North Coast and Peace regions have been initiated since the fiscal 2020 to fiscal 2024 Capital Plan was finalized. These additional investments and the related increase in unplanned future amortization will be offset by the expected increase in future revenue related to these projects."

2.132.1 With reference to Exhibit B-1, Appendices I and J, please indicate which three projects the response is referring to.

RESPONSE:

The three ex-plan projects noted in the preamble were approved after the fiscal 2020 to fiscal 2024 Capital Plan was finalized. Therefore, they were not included in the fiscal 2020 to fiscal 2024 Capital Plan and are not listed in Appendices I and J of the Application.

The three projects are Bear Mountain Terminal (BMT) to Dawson Creek (DAW) Transmission Voltage Conversion, North Montney Power Supply, and Prince George to Terrace Capacitors. For additional information on these projects, please refer to BC Hydro's response to BCUC IR 2.254.2.

132.0 Reference: Exhibit B-5, BCUC 1.110.1

The response states in part:

"Three ex-plan projects related to transmission system upgrades for the Liquefied Natural Gas and Oil and Gas sectors in the North Coast and Peace regions have been initiated since the fiscal 2020 to fiscal 2024 Capital Plan was finalized. These additional investments and the related increase in unplanned future amortization will be offset by the expected increase in future revenue related to these projects."

2.132.2 Do any of these three projects impact the revenue requirements in the test years?

RESPONSE:

This answer also responds to BCOAPO IRs 2.132.2.1 and 2.132.2.2

These three projects will not impact the revenue requirements in the Test Period because they are currently in Identification phase and do not go into service during the Test Period.

The expenditures on these projects in the Test Period will be managed within existing operating budgets. Please refer to BC Hydro's response to BCUC IR 2.254.2.1 for additional information on the funding requirements for these projects.

132.0 Reference: Exhibit B-5, BCUC 1.110.1

The response states in part:

"Three ex-plan projects related to transmission system upgrades for the Liquefied Natural Gas and Oil and Gas sectors in the North Coast and Peace regions have been initiated since the fiscal 2020 to fiscal 2024 Capital Plan was finalized. These additional investments and the related increase in unplanned future amortization will be offset by the expected increase in future revenue related to these projects."

2.132.2 Do any of these three projects impact the revenue requirements in the test years?

2.132.2.1 If yes please indicate which projects impact the revenue requirements for F2020 and F2021 and what the impact is.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.132.2.

British Columbia Old Age Pensioners' Organization Et Al Information Request No. **2.132.2.2** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

132.0 Reference: Exhibit B-5, BCUC 1.110.1

The response states in part:

"Three ex-plan projects related to transmission system upgrades for the Liquefied Natural Gas and Oil and Gas sectors in the North Coast and Peace regions have been initiated since the fiscal 2020 to fiscal 2024 Capital Plan was finalized. These additional investments and the related increase in unplanned future amortization will be offset by the expected increase in future revenue related to these projects."

2.132.2 Do any of these three projects impact the revenue requirements in the test years?

2.132.2.2 If yes, are there additional revenues from the projects in F2020 and F2021 sufficient to offset these impacts?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.132.2 and BCUC IR 2.254.2.1 for information on the funding requirements for these ex-plan projects within the test period.

133.0 Reference: Exhibit B-5, BCUC 1.133.1

2.133.1 With respect to the W.A.C. Bennett Dam Rip-Rap Upgrade (G000623), please confirm that the total capital additions are anticipated to be under the forecasted expected amount (per BCUC 1.107.1). If not, please explain.

RESPONSE:

Confirmed. BC Hydro expects the total capital additions for the W.A.C. Bennett Dam Rip-Rap Upgrade to be under the Expected Cost of $137 million.

133.0 Reference: Exhibit B-5, BCUC 1.133.1

2.133.2 With respect to the DVES: New DGR Strategic Property Purchase (900222), please explain the purpose of the purchase and why it was still considered prudent when the actual cost was almost double the original forecast.

RESPONSE:

BC Hydro notes that the New DGR Strategic Property Purchase was Planning ID 900221, and that project has been cancelled. Planning ID 900222 is the New Murrin Strategic Property Purchase, which was completed in March 2017 with the acquisition of 303 Vernon Drive for the future East Vancouver Substation.

The purpose of the property acquisition is to develop a new substation to replace the existing Murrin Substation. A new substation, on a new site, is required because Murrin substation:

- **Was built in 1947 and is getting close to end-of-life with more than half of the assets expected to degrade to poor or very poor condition in the next 10 to 20 years. This presents a reliability risk;**
- **Is on seismically unstable soil, with approximately half of the switchyard vulnerable to severe earthquake damage from liquefaction and settlement; and**
- **Has physical space constraints which make redevelopment of the substation in its current location challenging and costly.**

BC Hydro considers the acquisition of 303 Vernon Drive for the future East Vancouver Substation to be prudent because:

- **A new substation, in a new location, is required for the reasons discussed above; and**
- **There is a limited supply of suitable properties in East Vancouver with the specific property attributes required for the replacement substation. The property at 303 Vernon Drive was selected because it is located:**
  - **Close to the established transmission cable (which is in the lane adjacent to the property) and close to an eventual second transmission cable on Hastings Street, avoiding the need for higher incremental transmission costs to connect it to the power system;**
  - **On seismically stable ground;**

- **In the middle of the load serving area, avoiding the need for higher incremental distribution costs to connect to customers; and**
- **In a light industrial area, minimizing future stakeholder issues.**

A key factor that drove the acquisition cost above the original forecast was the high rate of property appreciation that was occurring in the Vancouver real estate market at the time.

The property is currently leased to a credit-worthy commercial tenant which minimizes BC Hydro’s holding costs until the construction of the East Vancouver Substation is initiated.

133.0 Reference: Exhibit B-5, BCUC 1.133.1

2.133.3 With respect to Transmission Project and Programs less than $5 M, the total actual capital additions in F2017 and F2018 are more than 60% higher ($519.2 M vs. $324.4 M) than the RRA values. Please provide an explanation for this significant variance.

RESPONSE:

Transmission Projects and Programs actual capital additions less than $5 million were 60 per cent higher than the fiscal 2017 and fiscal 2018 RRA plans on a combined two year basis, primarily due to:

- **Projects and programs with planned in-service dates additions prior to fiscal 2017 that shifted into fiscal 2017 and fiscal 2018, such as the Transmission Wood Structure and Framing Replacement Program ($15 million), the Overhead Rating Restoration Program ($21 million), Protection and Control Program ($10 million) and the Circuit Breaker Program ($42 million); and**
- **Several unplanned emergency equipment replacements ($20 million) and cost increases on the Outdoor Metalclad Switchgear Replacement projects ($31 million), as noted in Appendix G of the Application.**

The remaining difference of approximately $55 million includes:

- **Completion of the process to record capital additions for certain projects and programs that were put in-service at the end of fiscal 2016 but were recognized as capital additions in fiscal 2017 due to the time required to complete the analysis of which asset classes to allocate the costs; and**
- **Higher than expected trailing costs for projects put into service prior to fiscal 2017.**

134.0 Reference: Exhibit B-6, CEABC 1.13.2
Exhibit B-1, Appendix H, page 2

2.134.1 It is noted that for none of the five examples provided is there any reference to how the results of the project's assessment based on BC Hydro's enterprise framework for capital prioritization (per Exhibit B-1, Appendix H, page 2). Were each of the projects assessed and scored in accordance with the framework?

RESPONSE:

This response also responds to BCOAPO IRs 2.134.1.1 and 2.134.1.2.

CEABC IR 1.13.2 asked for examples of the evaluation of economic benefit vs. cost of the projects in relation to approval. BC Hydro approves projects in accordance with our financial approval policies and procedures, and not the prioritization assessments associated with evaluating investments for inclusion in the capital plan. All five projects listed in BC Hydro's response to CEABC IR 1.13.2 were reviewed by the BCUC, resulting in a decision to proceed. These reviews included an evaluation of the risks and drivers addressed by the projects. These projects were assessed in accordance with the capital prioritization framework that existed at the time the project was proposed for inclusion in the portfolio. BC Hydro's current enterprise-wide framework for capital prioritization was established in 2013, prior to which prioritization of capital spending was asset-centric, following top down investment targets established at the corporate level.

The application of BC Hydro's current enterprise-wide framework for capital prioritization results in risk or value scores, for investments that are not mandatory due to compliance and/or regulatory requirements, considering the financial, reliability, safety, environmental and reputational impacts associated with delaying the investment. An investment's risk or value score is one of the criteria BC Hydro considers when making prioritization decisions. Other criteria include resource and outage constraints (when considering the portfolio of investments).

The table below provides the risk scores for the example projects in our response to CEABC IR 1.13.2 that were assessed under the current enterprise-wide framework for prioritization:

Project	Risk Score
W.A.C. Bennett Dam Riprap Upgrade	**11.5**
Hugh Keenleyside (HLK) Spillway Upgrade	**12.0**
John Hart Generating Station Replacement	**11.0**

For the Dawson Creek/Chetwynd Area Transmission Project and the Ruskin Dam and Powerhouse Upgrade Project, risk scores are not available as these projects were initiated prior to the establishment of the current enterprise framework.

134.0 Reference: Exhibit B-6, CEABC 1.13.2
Exhibit B-1, Appendix H, page 2

2.134.1 It is noted that for none of the five examples provided is there any reference to how the results of the project’s assessment based on BC Hydro’s enterprise framework for capital prioritization (per Exhibit B-1, Appendix H, page 2). Were each of the projects assessed and scored in accordance with the framework?

2.134.1.1 If yes, what were the results and how, if at all, did these results inform the decision making?

RESPONSE:

Please refer to BC Hydro’s response to BCOAPO IR 2.134.1.

134.0 Reference: Exhibit B-6, CEABC 1.13.2
Exhibit B-1, Appendix H, page 2

2.134.1 It is noted that for none of the five examples provided is there any reference to how the results of the project's assessment based on BC Hydro's enterprise framework for capital prioritization (per Exhibit B-1, Appendix H, page 2). Were each of the projects assessed and scored in accordance with the framework?

2.134.1.2 If not, why not?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.134.1.

135.0 Reference: Exhibit B-5, BCUC 1.108.3 and 1.108.5
Exhibit B-6, CEC 1.89.1
Exhibit B-1, Appendix C, page 29

2.135.1 The response to BCUC 1.108.3 states that "The Current Capital Plan contains only high-level investment projections for fiscal 2025 to fiscal 2029 and cannot be split between growth and sustain". However, in Appendix C (page 29) BC Hydro provides a breakdown of the reduction in capital spending and specifically separates out sustainment-related spending. Please reconcile the response to BCUC 1.108.3 with the detail provided in Appendix C.

RESPONSE:

The breakdown provided on page 29 of Appendix C in the Application was an approximation of the expected categorization of the reductions based on the top down planning stage of BC Hydro's annual enterprise capital planning process described in Section 6.3 in Chapter 6 of the Application. The subsequent steps of the annual enterprise capital planning process were not completed for the fiscal 2025 to fiscal 2029 period. Without a detailed investment level plan for this period it is not possible to provide an accurate comparison of the growth and sustain capital additions of the Previous Capital Plan to the Current Capital Plan over the fiscal 2025 to fiscal 2029 period.

Detailed planning for fiscal 2025 to fiscal 2029 is ongoing and the next update to the capital plan will be completed by December 2019.

135.0 Reference: Exhibit B-5, BCUC 1.108.3 and 1.108.5
Exhibit B-6, CEC 1.89.1
Exhibit B-1, Appendix C, page 29

2.135.2 How did BC Hydro establish that the sustainment-related capital expenditures could be reduced by $1.6 B over the ten-year period F2020 to F2029?

RESPONSE:

BC Hydro established that sustainment related capital expenditures could be reduced by approximately $1.6 billion over the 10-year period through the top down planning process as part of the annual enterprise capital planning process.

Specifically, the moderation of sustainment investments was based upon a review of the long-term system performance trends, the current condition of the assets given historical investments and a change in the expected rate of replacement required to maintain system performance. This review determined that the overall portfolio level of sustainment expenditures over the 10-year period could be moderated, relative to previously planned amounts, to maintain an appropriate balance between affordability, system performance and risk. This review is described in more detail in section 6.3.2.2 in Chapter 6 of the Application.

135.0 Reference: Exhibit B-5, BCUC 1.108.3 and 1.108.5
Exhibit B-6, CEC 1.89.1
Exhibit B-1, Appendix C, page 29

2.135.2 How did BC Hydro establish that the sustainment-related capital expenditures could be reduced by $1.6 B over the ten-year period F2020 to F2029?

2.135.2.1 What degree of confidence does BC Hydro have in this reduced spending projection given that it is based only on "high level investment projections" (per CEC 1.89.1) and the detailed planning is yet to be undertaken?

RESPONSE:

BC Hydro has high confidence in the long-term investment level projections but recognizes that the planned reduction in sustainment expenditures relative to the previous plan must be accompanied by careful monitoring of asset condition and system performance.

Long term investment planning always has a degree of uncertainty. Detailed planning for fiscal 2025 to fiscal 2029 is ongoing and the next update to the plan will be completed by December 2019. The completion of this activity will provide BC Hydro with greater certainty on the long-term investment needs of the system and help ensure we are taking an appropriate balance between affordability, system performance and risk.

Any changes in the long-term investment needs over the fiscal 2025 to fiscal 2029 period will not impact the revenue requirements for the test period or the five-year net bill increase forecast provided in the Evidentiary Update.

136.0 Reference: Exhibit B-5, BCUC 1.135.3
Exhibit B-1, page 7-36

2.136.1 Please confirm that the Amortization of Capital Additions Regulatory Account means the customer (eventually) only pay for the actual amortization of assets incurred after the capital additions are recorded and amortization commences on the assets.

RESPONSE:

Variances between forecast and actual amortization of test period capital additions are deferred to the Amortization of Capital Additions Regulatory Account. Variances deferred to the Amortization of Capital Additions Regulatory Account are recovered over the next test period and customers only pay for the actual amortization.

Amortization of existing assets are not in scope of the Amortization of Capital Additions Regulatory Account and therefore variances between forecast and actual amortization of existing assets are to the account of the shareholder.

Amortization variances on existing assets may arise as a result of a reduction in the useful life of an asset or a write-off of an asset during a test period. For example, in the case of a reduction to the useful life of an asset, actual amortization expense is higher than forecast. As the variance is not subject to deferral, it is borne by the shareholder (all else equal).

136.0 Reference: Exhibit B-5, BCUC 1.135.3
Exhibit B-1, page 7-36

2.136.1 Please confirm that the Amortization of Capital Additions Regulatory Account means the customer (eventually) only pay for the actual amortization of assets incurred after the capital additions are recorded and amortization commences on the assets.

2.136.1.1 If not confirmed, please explain why.

RESPONSE:

Please refer to BC Hydro's response to BCOPAO IR 2.136.1.

137.0 Reference: Exhibit B-1, Pages 6-50 to 6-51 and Appendix O, pages 62-63

2.137.1 For purposes of forecasting growth-related transmission capital expenditures are BC Hydro's assumptions regarding the start-up dates for new customers the same as those used for load forecasting purposes (i.e., F2019 to F2021 only includes the start-up of "high likelihood projects" that are included in the load forecast for those years through its new binary assessment process)?

RESPONSE:

BC Hydro interprets the reference to "start-up dates for new customers" in this question to mean the customer's energization date or in-service date.

Most high likelihood customer requests included in the load forecast and the transmission capital plan will use the same in-service date. However, if there is a reasonable likelihood that the actual in-service date will occur after the customer's requested in-service date, the load forecast will be updated so that the fully expected load is reflected at the later date. The transmission capital plan may still show the original customer requested in-service date if BC Hydro has committed to deliver its interconnection capital project by the customer requested in-service date.

137.0 Reference: Exhibit B-1, Pages 6-50 to 6-51 and Appendix O, pages 62-63

2.137.1 For purposes of forecasting growth-related transmission capital expenditures are BC Hydro’s assumptions regarding the start-up dates for new customers the same as those used for load forecasting purposes (i.e., F2019 to F2021 only includes the start-up of “high likelihood projects” that are included in the load forecast for those years through its new binary assessment process)?

2.137.1.1 If not, what assumptions are made regarding the in-service/start-up dates for new customer for purposes of the forecast capital expenditures and asset in-service dates used in the Application?

RESPONSE:

Please refer to BC Hydro’s response to BCOAPO IR 2.137.1 where we explain what assumptions would be used.

137.0 Reference: Exhibit B-1, Pages 6-50 to 6-51 and Appendix O, pages 62-63

2.137.1 For purposes of forecasting growth-related transmission capital expenditures are BC Hydro's assumptions regarding the start-up dates for new customers the same as those used for load forecasting purposes (i.e., F2019 to F2021 only includes the start-up of "high likelihood projects" that are included in the load forecast for those years through its new binary assessment process)?

2.137.1.2 If there is any inconsistency between the assumptions made for load forecast purposes and capital planning purposes are rate-payers eventually held "whole" via BC Hydro's regulatory accounts and, if yes, how?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.137.1 for information on the in-service dates used in the load forecast and the transmission capital plan.

BC Hydro forecasts growth-related transmission capital expenditures using the information available; however, whether or not new transmission voltage customers proceed with their proposed projects and interconnections as well as the timing of these interconnections is highly uncertain. Please refer to BC Hydro's response to AMPC IR 2.35.5 for information on the factors that impact the timeline of requests.

To address this uncertainty, the load forecast uses customer-based forecasts with probability weightings as explained in BC Hydro's response to AMPC IR 2.23.1. In addition, KBUs in the Integrated Planning Business Group works with our People, Customer and Corporate Affairs Business Group to understand customer plans. This provides additional information for the load forecast and capital planning processes.

In implementing capital projects related to the interconnection of transmission voltage customers, the risk to ratepayers is actively managed by:

1. **Ensuring the construction of infrastructure does not advance without the customer entering into a Facilities Agreement and making the required financial commitments in the form of cash payment and/or security as required, in accordance with Tariff Supplement No. 6. This ensures that the rate-payer is not burdened with an investment not otherwise required; and**

2. Aligning schedules between BC Hydro's construction of infrastructure to serve the customer and the customer's required interconnection date. This ensures that infrastructure is not placed into service materially ahead of need.

However, if there are variances between forecast and actual amounts related to the load forecast and capital additions in a test period, ratepayers are held "whole" as a result of BC Hydro's regulatory accounts. Specifically:

- **Variances between forecast and actual load in a test period are deferred to the Non-Heritage Deferral Account; and**

- **Variances in amortization expense caused by variances between forecast and actual capital additions in a test period are deferred to the Amortization of Capital Additions Regulatory Account. Please refer to BC Hydro's response to to BCOAPO IR 2.136.1 for further information on the Amortization of Capital Additions Regulatory Account.**

Amounts deferred to the Non-Heritage Deferral Account and the Amortization of Capital Additions Regulatory Account over a test period are recovered or returned to ratepayers over a future test period(s). Accordingly, ratepayers are kept "whole" in that this results in them only paying actual costs.

138.0 Reference: Exhibit B-1, Appendix J, pages 71-72

2.138.1 Under Issues Being Addressed, please explain the basis for the 2028 and 2021 dates referenced in the discussion (i.e., why is the ability to supply load under normal conditions exceeded in 2021 but the system is able to maintain supply to all customers until 2028?).

RESPONSE:

Based on customer commitments, the transmission system load is expected to exceed the 400 MW transfer capability of the transmission system by fall 2021. At this point, no further load can be connected in the area without system reinforcement. However, the PRES project is expected to be in service by October 2021, and it will provide adequate power supply to meet the expected load growth.

Based on the Mid-Scenario of the May 2016 South Peace Load Forecast - December 2017 Update, the load is expected to grow by approximately 500 MW by fiscal 2028.

139.0 Reference: Exhibit B-5, BCUC 1.119.2

2.139.1 Please provide a schedule of key milestones for the PRES Project that demonstrates the project will be in service no later than December 31, 2022.

RESPONSE:

The table below shows the remaining key milestones for the PRES project.

Activity	Milestone Date
Complete clearing and access construction	**October 2019**
Complete construction, testing and commissioning at Shell Groundbirch Substation	**May 2020**
Complete construction, testing and commissioning at South Bank Substation	**December 2020**
Complete construction, testing and commissioning of transmission lines	**May 2021**
Project in-service date and commencement of operations	**October 2021**

140.0 Reference: Exhibit B-5, BCUC 1.121.4.1

2.140.1 Absent the thermal upgrades, is there/will there be sufficient load in the Peace region to utilize all of the available energy that cannot be transferred to domestic load centers outside the region or export markets?

RESPONSE:

This answer also responds to BCOAPO IR 2.140.1.1.

There is no thermal constraint in the Peace to Kelly 500 kV transmission corridor under system normal conditions. Under normal water conditions, BC Hydro expects to be able to transfer available energy from the Peace Region.

The thermal constraints occur only in summer when one of the 500 kV lines is out of service (N-1 contingency). For short duration line outages, transmission line thermal overload ratings can be used to maintain power transfers between the Peace Region and the load centre or export markets, which reduces the impact of the summer thermal restrictions. In the event of an extended line outage, BC Hydro would re-dispatch generation from other supply regions to alleviate the thermal overload in the Peace to Kelly 500 kV transmission corridor.

140.0 Reference: Exhibit B-5, BCUC 1.121.4.1

2.140.1 Absent the thermal upgrades, is there/will there be sufficient load in the Peace region to utilize all of the available energy that cannot be transferred to domestic load centers outside the region or export markets?

2.140.1.1 If not, what is the likely surplus energy in future years that will be "lost"?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.140.1 where we explain that we expect to be able to transfer energy from the Peace Region to domestic load centers or export markets, so no energy from the Peace Region is expected to be "lost".

141.0 Reference: Exhibit B-5, BCUC 1.122.1.1 and 1.122.2
Exhibit B-1, page 5F-38
Exhibit B-1, Appendix A, pages 66 & 67

2.141.1 With respect to Appendix A, Schedules 10 & 11, what are the actual (F2017 & F2018), the forecast F2019 and the planned F2020 and F2021 end of year values for i) net assets in-service related to EV charging stations owned by BC Hydro and ii) net contributions related to EV charging stations owned by BC Hydro?

RESPONSE:

The actual and forecast values included within the stated line items in Appendix A, Schedule 10.0 for EV charging stations are shown in the table below.

$ million	F2017 Actual	F2018 Actual	F2019 Forecast	F2020 Plan	F2021 Plan
Net assets in service Included within Sch. 10.0 line 16	0.4	0.0	0.0	0.0	0.0
Net assets in service Included within Sch. 10.0 line 22	0.0	3.4	2.5	0.2	2.2
Net contributions Included within Sch. 10.0 line 23	0.0	(0.4)	(2.1)	0.0	0.0

141.0 Reference: Exhibit B-5, BCUC 1.122.1.1 and 1.122.2
Exhibit B-1, page 5F-38
Exhibit B-1, Appendix A, pages 66 & 67

2.141.1 With respect to Appendix A, Schedules 10 & 11, what are the actual (F2017 & F2018), the forecast F2019 and the planned F2020 and F2021 end of year values for i) net assets in-service related to EV charging stations owned by BC Hydro and ii) net contributions related to EV charging stations owned by BC Hydro?

2.141.1.1 Also, for each schedule, in which row are the values reported?

RESPONSE:

Please refer to the table in BC Hydro’s response to BCOAPO IR 2.141.1 which includes the schedule and line information.

141.0 Reference: Exhibit B-5, BCUC 1.122.1.1 and 1.122.2
Exhibit B-1, page 5F-38
Exhibit B-1, Appendix A, pages 66 & 67

2.141.2 For each year, how many charging stations does this represent?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.248.1 for the full listing of charging station locations and in-service years. The table below shows the number of EV fast charging stations put in service by fiscal year.

Public Opening In-Service Fiscal Year	Number of Chargers
Fiscal 2017 and prior	30
Fiscal 2018	4
Fiscal 2019	25
Sub-total	59
Fiscal 2020 Plan	23
Fiscal 2021 Plan	-

141.0 Reference: Exhibit B-5, BCUC 1.122.1.1 and 1.122.2
Exhibit B-1, page 5F-38
Exhibit B-1, Appendix A, pages 66 & 67

2.141.3 Please explain the difference between the 56 fast charging stations owned by BC Hydro (per Exhibit B-1, page 5F-38) and the 30 fast charging stations referenced in the response to BCUC 1.122.1.1.

RESPONSE:

BC Hydro owns all 57[1] EV fast charging stations. The key difference between the first 30 stations deployed (i.e., Phase 1 deployment) and those that were subsequently deployed is that BC Hydro initially leased the EV fast charger to the respective site host.[2] The site host pays for electricity used by the charging station under the applicable rate schedule (e.g., Medium General Service rate). The site host may or may not charge customers a fee to use the charging station, and retains any associated revenue if there is a fee to use the station.

For stations added after the Phase 1 deployment, BC Hydro obtained a land lease/license agreement for each site, and BC Hydro is the operator of each station. Electricity used at each of these sites is recorded as BC Hydro "own use," and BC Hydro will collect revenues from the stations once a rate schedule is in place.

BC Hydro is responsible for the ongoing maintenance of the equipment at EV fast charging stations in both models.

1 **Since the Application was filed BC Hydro put into service an EV Station in Field.**

2 **With the exception of the Powertech Labs station which is operated by BC Hydro and used as a test site.**

142.0 Reference: Exhibit B-5, BCUC 1.134.1

2.142.1 Does the Application's capital expenditure forecast include the spending initially anticipated for the second property purchase?

RESPONSE:

No, the forecast in the Application does not include any expenditures for the second property purchase.

142.0 Reference: Exhibit B-5, BCUC 1.134.1

2.142.1 Does the Application's capital expenditure forecast include the spending initially anticipated for the second property purchase?

2.142.1.1 If yes, how much was the anticipated spending and where is it reflected in the Application?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.142.1.

143.0 Reference: Exhibit B-5, BCUC 1.148.3 & 1.148.4

2.143.1 Please provide a comparative analysis similar to that in BCUC 1.148.3 that compares: i) the current Application vs. ii) the results from using the DARR table mechanism approved by the BCUC in its Decision on BC Hydro's Fiscal 2009 - Fiscal 2010 Revenue Requirements Application.

RESPONSE:

BC Hydro notes that the financial information provided in this response has been prepared based on the information included in BC Hydro's Evidentiary Update.

Please refer to the first set of tables below for a comparative analysis of the Evidentiary Update based on BC Hydro's proposal in the Application to refund the net balance of the Cost of Energy Variance Accounts to the benefit of ratepayers during fiscal 2020 and fiscal 2021, versus the Evidentiary Update using the DARR table mechanism approved by the BCUC in its Decision on BC Hydro's Fiscal 2009 to Fiscal 2010 Revenue Requirements Application.

Scenario for BCOAPO IR 2.143.1

Evidentiary Update with the DARR table mechanism approved by the BCUC in its Decision on BC Hydro's Fiscal 2009 - Fiscal 2010 Revenue Requirements Application

a.) Forecast ending balances of Cost of Energy Variance Accounts, per Scenario					
$ million	F2020	F2021	F2022	F2023	F2024
Heritage Deferral Account	(441)	(234)	(69)	(16)	(1)
Non-Heritage Deferral Account	133	67	4	(5)	(1)
Trade Income Deferral Account	(237)	(126)	(37)	(8)	(1)
Total	(545)	(292)	(101)	(29)	(3)

a.) Forecast ending balances of Cost of Energy Variance Accounts, Evidentiary Update					
$ million	F2020	F2021	F2022	F2023	F2024
Heritage Deferral Account	(218)	(0)	(0)	(0)	(0)
Non-Heritage Deferral Account	101	0	(16)	(22)	(24)
Trade Income Deferral Account	(103)	0	0	0	0
Total	(219)	(0)	(16)	(22)	(24)

b.) Forecast amortization (refund) of Cost of Energy Variance Accounts, per Scenario					
$ million	F2020	F2021	F2022	F2023	F2024
Heritage Deferral Account	(61)	(220)	(171)	(54)	(15)
Non-Heritage Deferral Account	10	66	49	3	(5)
Trade Income Deferral Account	(33)	(118)	(92)	(29)	(8)
Total	(84)	(271)	(213)	(80)	(28)

b.) Forecast amortization (refund) of Cost of Energy Variance Accounts, Evidentiary Update					
$ million	F2020	F2021	F2022	F2023	F2024
Heritage Deferral Account	(281)	(222)	-	-	-
Non-Heritage Deferral Account	41	100	-	-	-
Trade Income Deferral Account	(164)	(105)	-	-	-
Total	(404)	(227)	-	-	-

c.) Forecast Deferral Account Rate Rider revenue, incremental forecast revenue shortfall, incremental forecast rate impact, and incremental forecast bill impact

$ million	**F2020**	**F2021**
DARR revenue, per Scenario	(84)	(271)
DARR revenue, Evidentiary Update (Appendix A, Sch 1.0, Ln 27)	0	0
Incremental Forecast DARR revenue	(84)	(271)

$ million	**F2020**	**F2021**
Revenue Shortfall, per Scenario	741	515
Revenue Shortfall, Evidentiary Update (Appendix A, Sch 1.0, Ln 29)	335	285
Incremental Forecast Revenue Deficiency	406	230

%	**F2020**	**F2021**
Annual Rate Increase, per Scenario	15.16	(4.07)
Annual Rate Increase, Evidentiary Update (Appendix A, Sch 1.0, Ln 30)	6.85	(0.99)
Incremental Forecast Rate Impact	8.31	(3.08)

%	**F2020**	**F2021**
Annual Bill Increase, per Scenario	8.03	(7.48)
Annual Bill Increase, Evidentiary Update (Appendix A, Sch 1.0, Ln 32)	1.76	(0.99)
Incremental Forecast Bill Impact	6.27	(6.49)

However, BC Hydro notes that, in the DARR table mechanism approved by the BCUC in its Decision on BC Hydro's Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, the DARR in a given fiscal year is based on the net balance in the Cost of Energy Variance Accounts as of September 30th of the previous fiscal year. However, because the March 31, 2019 ending net balance in the Cost of Energy Variance Accounts is now available, BC Hydro considers it appropriate (for the purpose of answering the question) to use the net balance in the Cost of Energy Variance Accounts as of March 31, 2019 to determine the DARR for fiscal 2020.

As a result, BC Hydro has included below a second comparative analysis of the Evidentiary Update, versus the Evidentiary Update using the DARR table mechanism approved by the BCUC in its Decision on BC Hydro's Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, using the updated March 31, 2019 net balance in the Cost of Energy Variance Accounts to determine DARR for fiscal 2020 in this scenario.

Scenario for BCOAPO IR 2.143.1

Evidentiary Update results with the DARR table mechanism approved by the BCUC in its Decision on BC Hydro's Fiscal 2009 - Fiscal 2010 Revenue Requirements Application, modified to use the more up-to-date March 31 2019 net balance of the Cost of Energy Variance Accounts to set fiscal 2020 DARR

a.) Forecast ending balances of Cost of Energy Variance Accounts, per Scenario					
$ million	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**
Heritage Deferral Account	(295)	(69)	18	18	19
Non-Heritage Deferral Account	110	22	(21)	(28)	(30)
Trade Income Deferral Account	(159)	(37)	9	10	10
Total	(344)	(84)	6	(0)	(1)

a.) Forecast ending balances of Cost of Energy Variance Accounts, Evidentiary Update					
$ million	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**
Heritage Deferral Account	(218)	(0)	(0)	(0)	(0)
Non-Heritage Deferral Account	101	0	(16)	(22)	(24)
Trade Income Deferral Account	(103)	0	0	0	0
Total	(219)	(0)	(16)	(22)	(24)

b.) Forecast amortization (refund) of Cost of Energy Variance Accounts, per Scenario					
$ million	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**
Heritage Deferral Account	(204)	(233)	(88)	-	-
Non-Heritage Deferral Account	32	87	28	-	-
Trade Income Deferral Account	(109)	(126)	(47)	-	-
Total	(281)	(271)	(107)	-	-

b.) Forecast amortization (refund) of Cost of Energy Variance Accounts, Evidentiary Update					
$ million	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**
Heritage Deferral Account	(281)	(222)	-	-	-
Non-Heritage Deferral Account	41	100	-	-	-
Trade Income Deferral Account	(164)	(105)	-	-	-
Total	(404)	(227)	-	-	-

c.) Forecast Deferral Account Rate Rider revenue, incremental forecast revenue shortfall, incremental forecast rate impact, and incremental forecast bill impact

$ million	**F2020**	**F2021**
DARR revenue, per Scenario	(281)	(271)
DARR revenue, Evidentiary Update (Appendix A, Sch 1.0, Ln 27)	0	0
Incremental Forecast DARR revenue	(281)	(271)

$ million	**F2020**	**F2021**
Revenue Shortfall, per Scenario	740	513
Revenue Shortfall, Evidentiary Update (Appendix A, Sch 1.0, Ln 29)	335	285
Incremental Forecast Revenue Deficiency	405	228

%	**F2020**	**F2021**
Annual Rate Increase, per Scenario	15.13	(4.08)
Annual Rate Increase, Evidentiary Update (Appendix A, Sch 1.0, Ln 30)	6.85	(0.99)
Incremental Forecast Rate Impact	8.28	(3.09)

%	**F2020**	**F2021**
Annual Bill Increase, per Scenario	4.16	(4.08)
Annual Bill Increase, Evidentiary Update (Appendix A, Sch 1.0, Ln 32)	1.76	(0.99)
Incremental Forecast Bill Impact	2.40	(3.09)

Under this scenario, a forecast bill <u>increase</u> of 4.16 per cent in fiscal 2020 is followed by a forecast bill <u>decrease</u> of 4.08 per cent in fiscal 2021. Therefore, BC Hydro considers that this approach creates unwarranted volatility and would not maintain rate stability for customers to the extent practicable.

BC Hydro further notes that its proposal to refund the credit balance in the Cost of Energy Variance accounts in fiscal 2020 and fiscal 2021 is done so that BC Hydro's required rate increase for fiscal 2020 remains unchanged, avoiding the need for a retrospective adjustment to fiscal 2020 interim rates and customer bills.

144.0 Reference: Exhibit B-5, BCUC 1.150.4

2.144.1 Please explain why the fact the low-carbon electrification projects BC Hydro has undertaken and the BC Hydro LCE Program fall within one (or more) class of prescribed undertakings defined under the Greenhouse Gas Reduction precludes them from falling within the definition of “demand side measure” in accordance with section 1 of the Clean Energy Act.

RESPONSE:

While it may be possible for a project to meet either definition, a public utility decides whether to pursue a project as either a prescribed undertaking under the GGRR or a “demand-side measure”.

Please refer to BC Hydro’s response to BCUC IR 2.250.6 where we explain that a public utility will determine whether a project constitutes a “prescribed undertaking” under the GGRR and would be obliged to put evidence forward to support its determination.

145.0 Reference: Exhibit B-5, BCUC 1.150.5

2.145.1 With respect to Table 10-14, the response states that the values represent the average measure life of the DSM expenditures proposed for the test period only. What is the difference/distinction between the 2-year and the 10-year values?

RESPONSE:

In BC Hydro's response to BCUC IR 1.150.5, we stated that the values in Table 10-14 represent the average measure life of the DSM expenditures proposed for the test period only. This statement was intended to clarify that the persistence of energy savings resulting from expenditures prior to the test period were not included in the calculation of weighted average persistence.

The values labelled "2-Year Period" in Table 10-14 of Chapter 10 of the Application represent the average measure life of the energy savings resulting from the DSM expenditures proposed for the test period only.

The values labelled "10-Year Period" represent the average measure life of the energy savings resulting from the DSM expenditures that are planned over the 10-year period from fiscal 2020 to fiscal 2029.

145.0 Reference: Exhibit B-5, BCUC 1.150.5

2.145.2 In each of the test years (F2020 and F2021) how much of the amortization of the DSM regulatory account is attributable to the DSM expenditures proposed for the test period?

RESPONSE:

DSM expenditures for a given fiscal year will begin to be amortized in the following fiscal year. Therefore DSM expenditures for fiscal 2020 will be amortized starting in fiscal 2021, over 15 years. DSM expenditures for fiscal 2021 will be amortized starting in fiscal 2022 (i.e., the next test period), over 15 years.

$7.3 million of the amortization of the DSM Regulatory Account in the test period is related to expenditures proposed for the test period. This represents one-fifteenth of the fiscal 2020 forecast expenditures of $109.1 million.

146.0 Reference: Exhibit B-5, BCUC 1.158.10
Exhibit B-6, CEC 1.75.1 to 1.75.5

2.146.1 CEC 1.75.3 indicates that business cases are developed for individual conversion projects. Were all the conversion projects that BC Hydro has undertaken and will be undertaking during the test period cost effective?

RESPONSE:

Yes, as indicated in BC Hydro's response to BCUC IR 1.158.6, voltage conversion is typically a more economical, and therefore more cost-effective, way to increase feeder capacity because it utilizes existing infrastructure as an alternative to building more costly new feeders and civil infrastructure.

Please refer to BC Hydro's Exhibit B-1, Appendix K, Attachment 1, page 87of 88 (Distribution Planning Practice - section 6.1 and 6.4.2: New Feeders and Voltage Conversion) where BC Hydro states the primary reasons for undertaking voltage conversion.

146.0 Reference: Exhibit B-5, BCUC 1.158.10
Exhibit B-6, CEC 1.75.1 to 1.75.5

2.146.1 CEC 1.75.3 indicates that business cases are developed for individual conversion projects. Were all the conversion projects that BC Hydro has undertaken and will be undertaking during the test period cost effective?

2.146.1.1 If not, what is the basis for approving/initiating those that weren't?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.146.1 which describes the voltage conversion drivers and benefits and voltage conversion as being more cost effective as it utilizes existing infrastructure as an alternative to building more costly new feeders and civil infrastructure.

147.0 Reference: Exhibit B-5, BCUC 1.161.1

2.147.1 The response states that "BC Hydro did not forecast project write-offs in prior test periods". In prior years, how were actual project write-offs treated (i.e., were they written off against net income and effectively paid for by the shareholder)?

RESPONSE:

As BC Hydro did not forecast project write-offs in the Previous Application, the actual write-offs were written-off against net income.

147.0 Reference: Exhibit B-5, BCUC 1.161.1

2.147.2 Under the current plan, how will the difference between the forecast and actual write-offs be treated?

RESPONSE:

Under the approach proposed in the Application, variances between actual and planned project write-offs would be written-off against net income.

As discussed in BC Hydro’s response to BCUC IR 2.261.1, project write-off variances will not be recorded to any regulatory accounts, such as the Amortization of Capital Additions Regulatory Account.

148.0 Reference: Exhibit B-6, BCOAPO 1.72.1

2.148.1 Apart from Finance charges, what other elements of BC Hydro's revenue requirement would be impacted by a change in the USD$/CAD$ exchange rate?

RESPONSE:

Apart from finance charges, other elements of BC Hydro's revenue requirements impacted by a change in the U.S. dollar to Canadian dollar exchange rate include some elements of cost of energy (including surplus sales), operating costs, capital expenditures (and the related amortization), and revenues from other utilities.

In general, a lower exchange rate (weaker Canadian dollar) would increase the revenue requirements in the test period where the underlying costs are in U.S. dollars. Examples include market energy purchases where purchases are in U.S. dollars, independent power producer purchases that are linked to energy prices in U.S. dollars, or thermal generation costs (Sumas natural gas prices are in US dollars).

In general, a lower exchange rate (weaker Canadian dollar) would decrease the revenue requirements in the test period where the underlying revenues or recoveries are in US dollars. Examples include surplus sales, Seattle City Light revenue or any net releases under the Non-Treaty Storage and Libby Coordination Agreements.

148.0 Reference: Exhibit B-6, BCOAPO 1.72.1

2.148.1 Apart from Finance charges, what other elements of BC Hydro's revenue requirement would be impacted by a change in the USD$/CAD$ exchange rate?

2.148.1.1 For these other elements of the revenue requirement would a lower exchange rate generally increase or decrease the test years' revenue requirements?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.148.1 where we provide a discussion on the impact of a lower exchange rate (weaker Canadian dollar) to the revenue requirements.

149.0 Reference: Exhibit B-5, BCUC 1.163.2 and 1.164.1

2.149.1 With respect to the table provided in the response to BCUC 1.163.2, please revise by adding two additional columns that set out for each row the amounts forecast to be paid in F2020 and F2021 by domestic customers and recovered through BC Hydro's bundled sales rates.

RESPONSE:

The following table updates the table provided in BC Hydro's response to BCUC IR 1.163.2 to reflect BC Hydro's Evidentiary Update and to add two additional columns that set out the amounts forecast to be paid in fiscal 2020 and fiscal 2021 by domestic customers and recovered through BC Hydro's bundled sales rates.

		F2020		F2021	
	Reference	Evidentiary Update	Re-covered Through Bundled Rates	Evidentiary Update	Re-covered Through Bundled Rates
NITS	Sch 3.4, L 32	967.8	967.8	965.0	965.0
Internal Ancillary Services	Sch 3.4, L 35	0.0	0.0	0.0	0.0
Internal Scheduling & Dispatch	Sch 3.4, L 37	3.8	3.8	4.0	4.0
Total Current Costs	Sch 3.4, L 21	971.6	971.6	969.0	969.0
Powerex PTP Charges	Sch 3.4, L 18	41.5	0	34.0	0
BC Hydro PTP Charges	Sch 3.4, L 19	19.1	19.1	35.0	35.0
PTP Allocation to Distribution	Sch 3.4, L 25	43.6	43.6	36.0	36.0
Total Internal PTP	Sch 3.4, L 67	104.2	63.7	105.0	71.0
External PTP	Sch 3.4, L 68	12.9	0	12.8	0
External Ancillary Services	Sch 3.4, L 36	2.8	0	2.8	0
External Scheduling & Dispatch	Sch 3.4, L 38	0.2	0	0.2	0
External OATT Revenue	Sch 3.4, L 73	15.9	0	15.9	0
Transmission Revenue Requirement	Sch 3.4, L 28	1,091.7	1,035.3	1,089.9	1,040.0

150.0 Reference: Exhibit B-5, BCUC 1.172.1
Exhibit B-1, pages 10-33 – 10-34

2.150.1 Please provide a detailed listing of what were considered to be portfolio-level costs prior to the March 2017 changes to the Demand-Side Measures Regulation.

RESPONSE:

Pages 75 to 78 of Appendix X of the Application provide details on Public Awareness and Indirect and Portfolio Enabling costs which were BC Hydro's portfolio level costs prior to the March 2017 amendments to the Demand-Side Measures Regulation.

These portfolio-level costs were allocated to each program in accordance with Directive 61 from the BCUC's Decision on BC Hydro's Fiscal 2005 to Fiscal 2006 Revenue Requirement Application.

The cost allocation process is described on pages 14 and 15 of Appendix Z of the Application.

150.0 Reference: Exhibit B-5, BCUC 1.172.1
Exhibit B-1, pages 10-33 – 10-34

2.150.1 Please provide a detailed listing of what were considered to be portfolio-level costs prior to the March 2017 changes to the Demand-Side Measures Regulation.

2.150.1.1 How, if at all, did what could be considered portfolio level costs change as a result of the 2017 changes to the Regulation?

RESPONSE:

The changes to the Demand-Side Measures Regulation in March 2017 that affected the allocation of costs at the portfolio level were specific to the treatment of energy management activities.

To align with the changes in the Demand-Side Measures Regulation in March 2017, BC Hydro has re-categorized its energy management activities. These costs are shown as Energy Management Activities within each sector. In accordance with the Demand-Side Measures Regulation, to determine cost effectiveness, these costs are not allocated to programs but are instead included at the portfolio-level. This process is described in section 10.5.7 of Chapter 10 of the Application.

150.0 Reference: Exhibit B-5, BCUC 1.172.1
Exhibit B-1, pages 10-33 – 10-34

2.150.2 BCUC 1.172.1 states that the Demand-Side Measures Regulation "does not endorse the attribution of portfolio-level costs to individual programs". Does the Regulation preclude the attribution of portfolio-level costs to individual programs?

RESPONSE:

The Demand-Side Measures Regulation (DSM Regulation) explicitly precludes the attribution of portfolio-level costs in some cases. As discussed in section 10.5.5 of Chapter 10 of the Application, section 4(4) of the DSM Regulation requires that "specified demand-side measures" be evaluated at a portfolio-level. "Specified demand-side measures" include energy efficiency training, community engagement and energy management programs that could be considered portfolio-level costs. In addition, section 4(5) of the DSM Regulation requires that a public awareness program be evaluated at the portfolio level. Public awareness programs could also be considered portfolio-level costs. The requirement that specified demand-side measures and public awareness programs be evaluated at the portfolio level precludes the attribution of the costs of these programs to individual programs.

Further, the DSM Regulation and the Guide to the DSM Regulation issued by the BC Ministry of Energy and Mines (Ministry Guide), which elaborates on the DSM Regulation, are prescriptive and formulaic regarding the calculation of cost-effectiveness. Section 4 of the DSM Regulation details the factors that are to be included in the cost-effectiveness calculations, while the Ministry Guide describes the cost-effectiveness calculations, and provides numerical calculations, none of which show that portfolio-level costs are to be attributed to programs. Given the detailed guidance provided in the DSM Regulation and Ministry Guide, it is BC Hydro's view that if the intent of the DSM Regulation was to attribute portfolio-level costs to programs, then the Ministry Guide would have included an example showing how these portfolio level costs would be attributed back to programs.

150.0 Reference: Exhibit B-5, BCUC 1.172.1
Exhibit B-1, pages 10-33 – 10-34

2.150.2 BCUC 1.172.1 states that the Demand-Side Measures Regulation "does not endorse the attribution of portfolio-level costs to individual programs". Does the Regulation preclude the attribution of portfolio-level costs to individual programs?

2.150.2.1 If yes, please indicate specifically where in Regulation this is addressed.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.150.2 for a discussion of the treatment of portfolio-level costs and the Demand-Side Measures Regulation.

150.0 Reference: Exhibit B-5, BCUC 1.172.1
Exhibit B-1, pages 10-33 – 10-34

2.150.2 BCUC 1.172.1 states that the Demand-Side Measures Regulation "does not endorse the attribution of portfolio-level costs to individual programs". Does the Regulation preclude the attribution of portfolio-level costs to individual programs?

2.150.2.2 Also, if yes, does it preclude jut the attribution certain types of portfolio-level costs or all portfolio-level costs?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.150.2 for a discussion of the treatment of portfolio-level costs and the Demand-Side Measures Regulation.

151.0 Reference: Exhibit B-1, Appendix X, page 7 of 8 (Table A-7)

2.151.1 Do the results reported for the Modified Total Resource Cost Test and the Total Resource Cost Test excluding NEBs for the individual DSM Programs include avoided capacity costs where appropriate?

RESPONSE:

Confirmed. Generation and Transmission and Distribution capacity benefits that are associated with the energy saved in our DSM plan are included where appropriate in the calculations for the cost-effectiveness results reported in all three columns of Table A-7: Modified Total Resource Cost Test, Total Resource Cost Test excluding NEBs, and Utility Cost Test. The only program that does not include capacity benefits is the Non-Integrated Areas Program.

151.0 Reference: Exhibit B-1, Appendix X, page 7 of 8 (Table A-7)

2.151.1 Do the results reported for the Modified Total Resource Cost Test and the Total Resource Cost Test excluding NEBs for the individual DSM Programs include avoided capacity costs where appropriate?

2.151.1.1 If not why, given Section 4 (1.1) (b) of the DSM Regulation which states "the avoided electricity cost, if any, respecting a demand-side measure, <u>in addition to the avoided capacity cost</u>, is…"? (emphasis added)

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.151.1 where we confirm the inclusion of avoided capacity costs.

151.0 Reference: Exhibit B-1, Appendix X, page 7 of 8 (Table A-7)

2.151.2 Footnote #2 states that "Capacity focused DSM is not included in the cost-effectiveness calculations". Does this mean that neither the cost of Capacity Focused DSM activities (per Table A-1) nor the capacity savings from these activities are include in the benefit cost ratios reported for the Portfolio Total?

RESPONSE:

Confirmed. Neither costs nor benefits associated with Capacity Focused DSM activities are included in the benefit cost ratios for the Portfolio Total.

Capacity Focused DSM costs have been excluded from the cost effectiveness calculations because this initiative is still in the trial and pilot project stage and therefore the associated benefits have not yet been quantified. Capacity Focused DSM is currently being tested in the market to understand the magnitude and dependability of the capacity savings for inclusion in our planning as potential alternatives to new generation capacity or grid (transmission and distribution) infrastructure.

Please refer to BC Hydro's response to BCOAPO IR 2.151.2.3 that shows the benefit cost ratios for the Portfolio Total if Capacity Focused DSM costs were included.

151.0 Reference: Exhibit B-1, Appendix X, page 7 of 8 (Table A-7)

2.151.2 Footnote #2 states that "Capacity focused DSM is not included in the cost-effectiveness calculations". Does this mean that neither the cost of Capacity Focused DSM activities (per Table A-1) nor the capacity savings from these activities are include in the benefit cost ratios reported for the Portfolio Total?

2.151.2.1 If not, what does it mean?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.151.2 where we confirm that Capacity Focused DSM costs and savings are excluded from cost-effectiveness.

151.0 Reference: Exhibit B-1, Appendix X, page 7 of 8 (Table A-7)

2.151.2 Footnote #2 states that "Capacity focused DSM is not included in the cost-effectiveness calculations". Does this mean that neither the cost of Capacity Focused DSM activities (per Table A-1) nor the capacity savings from these activities are include in the benefit cost ratios reported for the Portfolio Total?

2.151.2.2 Why was capacity focused DSM excluded from the cost effectiveness calculations?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.151.2 where we explain why Capacity Focused DSM costs and savings are excluded from cost-effectiveness.

151.0 Reference: Exhibit B-1, Appendix X, page 7 of 8 (Table A-7)

2.151.2 Footnote #2 states that "Capacity focused DSM is not included in the cost-effectiveness calculations". Does this mean that neither the cost of Capacity Focused DSM activities (per Table A-1) nor the capacity savings from these activities are include in the benefit cost ratios reported for the Portfolio Total?

2.151.2.3 What would be the benefit cost ratios for the Portfolio Total if capacity focused DSM was included?

RESPONSE:

The table below provides the benefit cost ratios for the Portfolio Total with and without Capacity Focused DSM costs. As shown in the table below, adding the costs of Capacity Focused DSM does not have a material impact on the benefit-cost ratios.

	LRMC ($105 per MWh)		Market Price ($30 per MWh)
	Modified Total Resource Cost Test	Total Resource Cost Test excluding NEBs	Utility Cost Test
PORTFOLIO TOTAL[1]	2.5	1.8	1.1
PORTFOLIO TOTAL with Capacity Focused DSM Costs	2.4	1.8	1.1

[1] This portfolio total is revised to exclude Thermo-Mechanical Pulp program activities in fiscal 2021, consistent with the updated DSM expenditure request provided in BC Hydro's Evidentiary Update

152.0 Reference: Exhibit B-5, BCUC 1.175.1, 1.175.2 and 1.175.3

2.152.1 With respect to Table A-7, for purposes of determining the values for the TRC Test excluding NEBs – was the 40% adjustment required for certain DSM programs per Section 4 (2) also excluded?

RESPONSE:

Section 4(2) of the Demand Side Measures Regulation stipulates that a 40 per cent adder to the benefits of the Low Income Program is to be included in the Total Resource Cost (TRC) Test. The 40 per cent adder is not applicable to other programs in BC Hydro's DSM Plan.

In Table A-7 of Appendix X of the Application, the 'TRC excluding NEBs' benefit-cost ratio of 2.7 for the Low Income Program excluded the 40 per cent adder for Low Income in error. The correct value, with the 40 per cent adder included, is 3.7.

152.0 Reference: Exhibit B-5, BCUC 1.175.1, 1.175.2 and 1.175.3

2.152.2 Please clarify the difference between what the benefit cost ratios reported in Table A-7 (Appendix X) and those reported in BCUC 1.175.1 represents.

RESPONSE:

The only difference is the timeframe. The benefit cost ratios reported in Table A-7 of Appendix X of the Application represent fiscal 2020 to fiscal 2022 activities whereas those reported in BC Hydro’s response to BCUC IR 1.175.1 represent fiscal 2020 to fiscal 2021 activities.

152.0 Reference: Exhibit B-5, BCUC 1.175.1, 1.175.2 and 1.175.3

2.152.3 With respect to BCUC 1.175.2:

2.152.3.1 What gives rise to the negative values for Residential-Retail programs?

RESPONSE:

BC Hydro's response to BCUC IR 1.175.2 provides the Long-Run Marginal Cost (LRMC) values that would result in a Total Resource Cost (TRC) benefit-cost ratio (excluding Non-Energy Benefits) equal to 1.0 for each program.

A negative LRMC value can arise if other benefits in the TRC calculation (specifically, capacity benefits and natural gas benefits) outweigh the costs in the TRC calculation. The costs included in the TRC are customer costs and utility non-incentive costs.

The Retail program's LRMC value is negative primarily because its customer costs are negligible as a result of the high volume of LED Lighting measures within the program. LEDs have a low incremental customer cost because a customer avoids the cost of purchasing multiple inefficient bulbs over the longer life of the more efficient LED bulb, which reduces the net cost of the LED light bulb to the customer.

152.0 Reference: Exhibit B-5, BCUC 1.175.1, 1.175.2 and 1.175.3

2.152.3 With respect to BCUC 1.175.2:

2.152.3.2 If the 40% adjustment required for certain DSM programs per Section 4 (2) was excluded for purposes of determining the values for the TRC Test excluding NEBs in Table A-7, provide a revised version of BCUC 1.175.2, where it is excluded.

RESPONSE:

The Demand-Side Measures Regulation section 4 (2) stipulates that a 40 per cent adder to the benefits of the Low Income Program is to be included in the Total Resource Cost Test. The 40 per cent adder is not applicable to other programs in BC Hydro's DSM Plan.

As noted in BC Hydro's response to BCOAPO IR 2.152.1, the 40 per cent adder was excluded from Table A-7 in error. However, it was included in the table in BC Hydro's response to BCUC IR 1.175.2, which calculated the LRMC required for each program to result in a benefit-cost ratio equal to 1.0. If we exclude the 40 per cent adder from the calculation, the LRMC breakeven point for the Low Income Program would be $24 per MWh.

While the table in BC Hydro's response to BCUC IR 1.175.2 includes the 40 per cent adder for the Low Income Program, an error was discovered in the calculation of the adder. Please refer to BC Hydro's response to BCUC IR 2.274.1, which replicates the table provided in BCUC IR 1.175.2 for the test period only, and corrects the error identified.

153.0 Reference: Exhibit B-5, BCUC 1.181.2
Exhibit B-1, Appendix X, Tables A-4 and A-5

2.153.1 Why is it possible in Tables A-4 and A-5 to attribute incremental energy and capacity savings to Residential Energy Management Activities but not to Commercial and Industrial Energy Management Activities?

RESPONSE:

It was possible to attribute energy and capacity savings to Residential Energy Management Activities because energy savings were already attributed to the Residential Behaviour Program prior to the changes to the Demand-Side Measures Regulation. The Residential Behaviour Program was a stand-alone program that had been offered for many years and consisted of a collection of Energy Management Activities designed to assist customers to optimize energy use. There was no equivalent stand-alone program in the Commercial or Industrial sectors.

To comply with the Demand-Side Measures Regulation BC Hydro identified energy management activities and categorized the associated expenditures as an Energy Management Activities Program within each sector. The Residential Behaviour Program expenditures were identified as Energy Management Activities.

If BC Hydro did not report the energy savings from the Residential Behaviour Program with the Residential Energy Management Activities Program, the energy savings would need to be allocated across the remaining Residential Programs. There would be no clear method for performing this allocation. The allocation would improve the results for each of the remaining Residential programs but would result in no change to the cost-effectiveness of the Portfolio.

153.0 Reference: Exhibit B-5, BCUC 1.181.2
Exhibit B-1, Appendix X, Tables A-4 and A-5

2.153.2 The footnotes to Tables A-4 and A-5 indicate that the Commercial and Industrial Energy Management Activities enable and support energy and capacity savings reported under other programs for these sectors.

2.153.2.1 Please indicate in what ways the Energy Management Activities related to these sectors enable and support energy and capacity savings reported under other programs.

RESPONSE:

The overall intent of the energy management activities is to support customers in their optimization of energy use, which also leads to increased participation in BC Hydro's existing DSM programs.

Energy management activities accomplish this by encouraging organizations to consider energy efficiency and by providing customers with the information, support and tools required to inform energy use decisions. For example:

- **Conducting energy management assessments with customers to review their organization's energy management practices and procedures and move them towards best practices;**
- **Providing energy managers that become dedicated energy champions to work within a company to help create and implement a corporate level strategic energy management program with targets; and**
- **Providing training to trade allies/supply-chain partners so that they are educated on energy management and energy efficient products and aware of the details of the available BC Hydro programs. These allies/partners help customers assess facility opportunities, complete customer projects, and provide energy information support.**

As a result of the energy management activities (including the examples above), energy efficiency projects are more likely to come forward and realize energy and capacity savings within BC Hydro's Leaders in Energy Management Commercial or Industrial programs.

153.0 Reference: Exhibit B-5, BCUC 1.181.2
Exhibit B-1, Appendix X, Tables A-4 and A-5

2.153.2 The footnotes to Tables A-4 and A-5 indicate that the Commercial and Industrial Energy Management Activities enable and support energy and capacity savings reported under other programs for these sectors.

2.153.2.2 Doesn't separating these costs out (and not including them as part of the individual DSM program costs) result in the benefit ratios for DSM programs in these sectors being overstated? If not, why not?

RESPONSE:

An allocation of the energy management activities costs to individual programs would result in lower benefit cost ratios for the programs. Energy management activities are categorized by the Demand-Side Measures Regulation as "specified demand-side measures" and as such are properly evaluated on a portfolio basis.

The following measures are categorized as specified demand-side measures:

- **Education programs for students in schools and post-secondary institutions;**
- **Funding of energy efficiency training;**
- **Community engagement programs;**
- **Energy management programs;**
- **Technology innovation programs; or**
- **Financial or other resources provided in support of codes and standards.**

For the purpose of determining the cost-effectiveness of specified demand-side measures, section 4 (4) of the Demand-Side Measures Regulation states that the cost-effectiveness must be determined by determining whether the portfolio is cost-effective as a whole.

Therefore the allocation of these expenditures to individual programs for the purpose of cost effectiveness would be inconsistent with the treatment required in the Demand Side Measures Regulation.

153.0 Reference: Exhibit B-5, BCUC 1.181.2
Exhibit B-1, Appendix X, Tables A-4 and A-5

2.153.3 In the case of the Residential sector it is noted that both energy and capacity savings are attributed to Residential Energy Management Activities. Do Residential Energy Management Activities also serve to enable and support energy and capacity savings reported under for other Residential DSM programs?

RESPONSE:

Yes, the overall intent of residential energy management activities is to support customers' optimization of energy use which also serves to enable and support energy and capacity savings reported under other residential DSM programs.

Energy management activities accomplish this by providing customers with the information, support and tools required to inform energy use decisions. For example:

- **Support to industry partners to provide customers with access to trained and qualified trade allies/supply-chain partners who are knowledgeable on the details of the available BC Hydro programs and can assist customers in understanding their energy management options and completing customer projects/purchases;**
- **Providing feedback and energy data to customers through the Energy Visualization Portal, and home energy monitors. This results in increased awareness and understanding of energy consumption patterns among BC Hydro's customers, enabling them to look for other opportunities to take action to reduce their bill; and**
- **Providing the opportunity for customers to enter into energy challenges, receiving status updates and tips as they strive to reduce household electricity consumption, or maintain a previous reduced consumption level. This active engagement provides tailored communications on additional actions and DSM programs that can assist customers in reducing their consumption.**

153.0 Reference: Exhibit B-5, BCUC 1.181.2
Exhibit B-1, Appendix X, Tables A-4 and A-5

2.153.3 In the case of the Residential sector it is noted that both energy and capacity savings are attributed to Residential Energy Management Activities. Do Residential Energy Management Activities also serve to enable and support energy and capacity savings reported under for other Residential DSM programs?

2.153.3.1 If yes, please indicate how.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.153.3 where we explain that Residential Energy Management Activities enable and support energy and capacity savings reported under other residential DSM programs by providing customers with the information, support and tools required to inform energy use decisions.

154.0 Reference: Exhibit B-6, AMPC 1.5.7

2.154.1 The response confirms that "DSM with a levelized utility cost less than $30 per MWh reduces BC Hydro's overall revenue requirements and overall customer bills". Does DSM with a levelized utility cost less than $30 per MWH reduce the rates paid by all customer classes?

RESPONSE:

The Utility Cost Test estimates the impact on BC Hydro's overall revenue requirement, which is synonymous with overall customer bills. If the levelized utility cost of DSM is less than $30 per MWh, the overall bill for each customer class will be lower. The Utility Cost Test does not, however, provide an indication of the impact of DSM on rates.

DSM can reduce customer bills within a class, but not necessarily reduce rates. This is because DSM reduces the amount of energy sales from which BC Hydro recovers its costs. As a result, while the revenue requirement (customer bills) is decreasing, there could still be an upward pressure on rates as BC Hydro's revenue requirement may need to be recovered from a lower amount of energy sales.

DSM at a levelized utility cost less than $30 causes an upward pressure on rates because the rate for each customer class is larger than the market export price used to value the energy savings during a surplus period. However, the market export revenues and associated capacity benefits from the DSM savings are greater than the cost of DSM, so that the overall revenue requirements and overall bill for each customer class will still be lower.

154.0 Reference: Exhibit B-6, AMPC 1.5.7

2.154.1 The response confirms that “DSM with a levelized utility cost less than $30 per MWh reduces BC Hydro’s overall revenue requirements and overall customer bills”. Does DSM with a levelized utility cost less than $30 per MWH reduce the rates paid by all customer classes?

2.154.1.1 If yes, please explain why.

RESPONSE:

Please refer to BC Hydro’s response to BCOAPO IR 2.154.1 for a discussion of the impacts on customer bills and rates of DSM at a levelized utility cost less than $30 per MWh.

155.0 Reference: Exhibit B-5, BCUC 1.15.3
Exhibit B-6, AMPC 1.5.9; and INCE 1.2.1

2.155.1 With respect to AMPC 1.5.9, why was a 15-year period (i.e., 2020-2034) used to calculate the levelized market price when, with committed domestic resources (including Site C), the planning view LRB only shows an energy surplus until fiscal 2027 (per INCE 1.2.1)?

RESPONSE:

In light of the current energy surplus and the DSM moderation strategy, we use market price in the Utility Cost Test for DSM initiatives to ensure cost-effectiveness. Please refer to BC Hydro's response to BCOAPO IR 2.155.3 where we discuss that BC Hydro has adopted the market price as a conservative interim assumption for evaluating BC Hydro's opportunity cost of energy during both surplus and deficit periods.

The market price forecast used in the DSM cost-effectiveness calculation is a forecast of prices with annual values that vary from year to year, over a 30-year period.

The $30 per MWh value is not a direct input to DSM's cost-effectiveness calculations. As described in BC Hydro's response to AMPC IR 1.5.9, the $30 per MWh market price is a levelized value, calculated over the market price forecast period of fiscal 2020 to fiscal 2034. It is intended to be used as a point of reference when describing market prices in a planning context.

155.0 Reference: Exhibit B-5, BCUC 1.15.3
Exhibit B-6, AMPC 1.5.9; and INCE 1.2.1

2.155.2 The response to AMPC 1.5.9 states that “For the purpose of assessing the TRC under that regulation, the levelized energy LRMC of $105/MWh was used for the duration of the forecast period. Internal decisions on demand side measures are based on the utility cost test at market price, not the LRMC”.

2.155.2.1 Please clarify what is meant by “internal decisions on DSM measures”.

RESPONSE:

Internal decisions on DSM measures refers to decisions made within BC Hydro to approve the DSM Plan.

155.0 Reference: Exhibit B-5, BCUC 1.15.3
Exhibit B-6, AMPC 1.5.9; and INCE 1.2.1

2.155.2 The response to AMPC 1.5.9 states that "For the purpose of assessing the TRC under that regulation, the levelized energy LRMC of $105/MWh was used for the duration of the forecast period. Internal decisions on demand side measures are based on the utility cost test at market price, not the LRMC".

2.155.2.2 In particular, does this mean that the decisions regarding the proposed DSM plan (per Appendix X) are based on the utility cost test at market price?

RESPONSE:

Confirmed. Internal decisions regarding the proposed DSM Plan (per Appendix X) are based on the Utility Cost test at market price. The Total Resource Cost test is also presented for internal decisions to understand cost-effectiveness per the DSM Regulation and the relative cost-effectiveness of DSM to other resource options.

155.0 Reference: Exhibit B-5, BCUC 1.15.3
Exhibit B-6, AMPC 1.5.9; and INCE 1.2.1

2.155.3 Apart from those related to DSM, what other internal decisions affecting the revenue requirement in the test years rely of the value ascribed to BC Hydro's future opportunity cost for energy (e.g., EPA renewals, new EPA agreements, new capital spending commitments, etc.)?

RESPONSE:

This response also provides BC Hydro's response to BCOAPO IR 2.155.3.1.

Generally, internal decisions related to EPA renewals, new EPAs and new capital additions (on the integrated system) rely on the value ascribed to BC Hydro's opportunity cost. However, BC Hydro also considers other benefits prior to proceeding with individual initiatives, such as: safety, reliability, compliance with environmental or regulatory requirements, and benefits to First Nations and/or local communities.

In the Application, BC Hydro's planned revenue requirement for the initiatives described above generally relied on our previous approach to evaluating BC Hydro's opportunity cost of energy. Specifically, BC Hydro used market prices in periods of surplus and Long Run Marginal Cost (LRMC) in periods of deficit.

As discussed in BC Hydro's response to BCUC IR 1.15.2.1, BC Hydro recently adopted the market price as a conservative interim assumption for evaluating BC Hydro's opportunity cost of energy during both surplus and deficit periods. This interim approach applies to internal decisions in the Test Period related to the initiatives described above; however, the change is not expected to have a material impact on the actual costs of those initiatives in the Test Period because:

- **For EPA renewals and new EPAs, as set out in BC Hydro's response to BCUC IR 1.15.2.1, the change would only impact run of river hydro EPA renewals. The total cost of these renewals in the Test Period is approximately $0.1 million and as a result, the impact is not expected to be material. Further, should any variance occur, ratepayers will only pay the actual cost as variances between forecast and actual EPA costs are deferred to the Non-Heritage Deferral Account; and**
- **For capital additions, capital investments in the Test Period are driven by the other benefits described above and not by the opportunity cost of energy.**

155.0 Reference: Exhibit B-5, BCUC 1.15.3
Exhibit B-6, AMPC 1.5.9; and INCE 1.2.1

2.155.3 Apart from those related to DSM, what other internal decisions affecting the revenue requirement in the test years rely of the value ascribed to BC Hydro's future opportunity cost for energy (e.g., EPA renewals, new EPA agreements, new capital spending commitments, etc.)?

2.155.3.1 In each case, what has BC Hydro used as the basis for the opportunity cost energy for purposes of establishing the revenue requirement proposed for the test years?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.155.3.

156.0 Reference: Exhibit B-6, BCOAPO 1.81.1.1 and BCSEA 1.51.3

2.156.1 What impact, if any, does BC Hydro expect the flattening of the Residential tiered energy rate would have on the persistence of the conservation savings that have been attributed to the RIB rate?

RESPONSE:

BC Hydro is not able to provide the information requested as we have not completed analysis of the impact of flattening the RIB rate on the persistence of conservation savings that have been attributed to the RIB rate.

157.0 Reference: Exhibit B-6, BCSEA 1.51.2
Exhibit B-1, Appendix X, Tables A-4 and A-5

2.157.1 The response states "The forecast of TSR energy savings is based on historical and forecast demand-side management projects and incremental self-generation projects at specific TSR customer facilities." How does BC Hydro distinguish between DSM projects and incremental self-generation projects that are attributable to the overall rate level (e.g., would have occurred in the absence of the stepped rate for transmission customers) and projects that can be directly attributed the Transmission Service Rate?

RESPONSE:

In developing the forecast of savings attributable to the Transmission Service Rate, BC Hydro has not assessed how much of these savings would have occurred as a result of changes to the overall rate level but in the absence of the stepped rate.

Savings from changes to the overall rate level are captured by the elasticity assumptions in the October 2018 Load Forecast, as provided in Table 7-21 in Appendix O of the Application, and equate to 20 GWh[1] by the end of the test period. Even if this entire amount was assumed to overlap with the savings in the DSM Plan attributed to the Transmission Service Rate over the test period, this would represent a small portion of the Transmission Service Rate savings in the DSM Plan.

1 BC Hydro's response to BCUC IR 2.211.2 outlines the updated real rate decreases over the test period as filed in BC Hydro's Evidentiary Update, relative to what was used in the October 2018 Load Forecast. Using these updated rate decreases may result in an increase in load, rather than reductions, and as a result there may be no potential overlap with the Transmission Service Rate savings during the test period.

158.0 Reference: Exhibit B-6, BCSEA 1.53.1

2.158.1 What DSM programs has BC Hydro currently scheduled for evaluation in F2019, F2020 and F2021?

RESPONSE:

BC Hydro's current evaluation workplan for DSM programs, rate structures and codes and standards for fiscal 2019, fiscal 2020 and fiscal 2021 is outlined in the table below.

	F2019	F2020	F2021
Codes and Standards			
General Service Lamps			X
Televisions	X		
Commercial Building Code	X		
Rate Structures			
Residential			
Industrial Transmission	X[1]		
Residential Sector Programs			
Behaviour		X	
Low Income			
Home Renovation Rebate		X	
Retail			X
Commercial Sector Programs			
Leaders in Energy Management – Commercial	X		
Leaders in Energy Management – Commercial - Continuous Optimization		X	
New Construction		X	
Industrial Sector Programs			
Leaders in Energy Management – Industrial Transmission		X	
Leaders in Energy Management - Industrial - Distribution			X
Load Displacement	X[1]		
Thermo-Mechanical Pulp			

1 **Started in fiscal 2019, will complete fiscal 2020.**

158.0 Reference: Exhibit B-6, BCSEA 1.53.1

2.158.2 Based on the plan set out in response to part 1 which DSM programs will not have been subject to an evaluation over the F2017 to F2021 period?

RESPONSE:

The only DSM program that will not have been subject to an evaluation over the fiscal 2017 to fiscal 2021 period is the Thermo-Mechanical Pulp program. An evaluation for the Thermo-Mechanical Pulp program is not planned during this time period because of the long lead times associated with project implementation. In addition, each project will be subject to its own Measurement and Verification plan which requires a sufficient period for the project to operate and data to be collected. The current plan is to evaluate the Thermo-Mechanical Pulp program in fiscal 2022.

159.0 Reference: Exhibit B-6, CEABC 1.15.1 and 1.15.4; and INCE 1.2.1
Exhibit B-5, BCUC 1.186.2

2.159.1 In calculating the cost effectiveness of the projects, what assumptions did BC Hydro make regarding future increases in BC Hydro rates for purposes of forecasting the additional revenues that will be earned?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.84.1 where we provide the assumptions regarding future rate increases used to calculate the cost-effectiveness of the projects.

159.0 Reference: Exhibit B-6, CEABC 1.15.1 and 1.15.4; and INCE 1.2.1
Exhibit B-5, BCUC 1.186.2

2.159.2 Why was the time period up to F2031 used for purposes of calculating the GGRR NPV?

RESPONSE:

The Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) provides the parameters for calculating cost-effectiveness. These parameters include the time period to be used. The “specified year” is listed in section 4(1)(b) of the GGRR as calendar 2030. BC Hydro’s fiscal year 2031 starts on April 1, 2030 and thus is the most appropriate year to use.

159.0 Reference: Exhibit B-6, CEABC 1.15.1 and 1.15.4; and INCE 1.2.1
Exhibit B-5, BCUC 1.186.2

2.159.3 The tables provided in response to CEABC 1.15.1 only provide incremental energy through to F2022. For any of the projects, is there expected to be incremental energy after F2022?

RESPONSE:

The tables provided in the response to CEABC IR 1.15.1 represent a forecast of the incremental energy from Project 1, 2, 3, and projects that will be developed through the Low Carbon Electrification Programs. No additional incremental energy was planned for after fiscal 2022 for these projects and Low Carbon Electrification Programs. However, timing delays could shift some incremental energy beyond fiscal 2022.

159.0 Reference: Exhibit B-6, CEABC 1.15.1 and 1.15.4; and INCE 1.2.1
Exhibit B-5, BCUC 1.186.2

2.159.3 The tables provided in response to CEABC 1.15.1 only provide incremental energy through to F2022. For any of the projects, is there expected to be incremental energy after F2022?

2.159.3.1 If yes, please provide revised version of CECBC 1.15.1 that shows the incremental energy for all the year impacted.

RESPONSE:

Please refer to BC Hydro’s response to BCOAPO IR 2.159.3.

159.0 Reference: Exhibit B-6, CEABC 1.15.1 and 1.15.4; and INCE 1.2.1
Exhibit B-5, BCUC 1.186.2

2.159.4 If for any of the projects there is expected to be incremental energy after F2026, how was the fact that the planning view LRB with just committed resources shows there is no surplus after this date (per INCE 1.2.1) taken into account?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 2.159.3, where we discuss the timing of incremental energy after fiscal 2022. BC Hydro's current plan does not include incremental energy after fiscal 2026 for LCE projects.

Future LCE activities beyond the test period will be informed by Phase Two of the Comprehensive Review of BC Hydro.

59.0 Topic: Chapter 4. Cost of Energy
Biomass Energy Program and Retired Railway Ties

Reference: Application, Exhibit B-1, s.4.3.2, pdf p.237; Exhibit B-6, BC Hydro Response to BCSEA IR 1.13.1, pdf p.671

BCSEA asked in IR 1.13.1: “Is it BC Hydro’s intention that a long-term EPA with Atlantic Power for power from the Williams Lake biomass generation facility would include a requirement that power delivered under the agreement would be exclusively from clean or renewable resources?”

BC Hydro responded: “Under the Biomass Energy Program, BC Hydro intends to purchase energy generated from clean or renewable resources, and the terms of the Electricity Purchase Agreements are still under development.” [underline added]

BCSEA asked in IR 1.13.2: “More generally, is it BC Hydro’s intention that long-term EPAs with biomass generation facilities will require exclusively clean or renewable fuel?

BC Hydro responded: “At this time, BC Hydro has not made any decisions regarding the terms and conditions for biomass Electricity Purchase Agreements awarded under any future procurement process beyond the Biomass Energy Program.” [underline added]

2.59.1 What is the status of BC Hydro’s new Electricity Purchase Agreements with Atlantic Power and other operators of biomass generation facilities?

RESPONSE:

This answer also responds to BC Hydro’s response to BCSEA IRs 2.59.2 and 2.59.3.

At this time, confidential bilateral negotiations are still underway for new Electricity Purchase Agreements related to biomass facilities eligible for the Biomass Energy Program. As a result, BC Hydro does not yet know what the outcome of that process will be.

59.0 Topic: Chapter 4. Cost of Energy
Biomass Energy Program and Retired Railway Ties

Reference: Application, Exhibit B-1, s.4.3.2, pdf p.237; Exhibit B-6, BC Hydro Response to BCSEA IR 1.13.1, pdf p.671

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BCSEA asked in IR 1.13.2: "More generally, is it BC Hydro's intention that long-term EPAs with biomass generation facilities will require exclusively clean or renewable fuel?

BC Hydro responded: "At this time, BC Hydro has not made any decisions regarding the terms and conditions for biomass Electricity Purchase Agreements awarded under any future procurement process beyond the Biomass Energy Program." [underline added]

2.59.2 Do the terms of BC Hydro's new long-term EPA with Atlantic Power for power from the Williams Lake biomass generation facility preclude delivery of power from retired railway ties?

RESPONSE:

Please refer to BC Hydro's response to BCSEA IR 2.59.1.

59.0 Topic: Chapter 4. Cost of Energy
Biomass Energy Program and Retired Railway Ties

Reference: Application, Exhibit B-1, s.4.3.2, pdf p.237; Exhibit B-6, BC Hydro Response to BCSEA IR 1.13.1, pdf p.671

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BC Hydro responded: "Under the Biomass Energy Program, BC Hydro intends to purchase energy generated from clean or renewable resources, and the terms of the Electricity Purchase Agreements are still under development." [underline added]

BCSEA asked in IR 1.13.2: "More generally, is it BC Hydro's intention that long-term EPAs with biomass generation facilities will require exclusively clean or renewable fuel?

BC Hydro responded: "At this time, BC Hydro has not made any decisions regarding the terms and conditions for biomass Electricity Purchase Agreements awarded under any future procurement process beyond the Biomass Energy Program." [underline added]

2.59.3 Has BC Hydro determined whether its long-term EPAs with biomass generation facilities will require exclusively clean or renewable fuel?

RESPONSE:

Please refer to BC Hydro's response to BCSEA IR 2.59.1.

60.0 Topic: Chapter 4. Cost of Energy
First Nations energy projects

Reference: Application, Exhibit B-1, s.4.3.2, pdf p.234

"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." [underline added]

2.60.1 Apart from the small number of new First Nations energy projects referred to in the Application, is BC Hydro working toward additional electricity purchase agreements with First Nations that may not be completed in the F2020-F2021 time period?

RESPONSE:

At this time, on the integrated system, BC Hydro is not working towards additional electricity purchase agreements (EPAs) with First Nations other than the seven expected EPAs listed under the "Expected SOP Projects and other First Nations Commitments" category shown in Table 4-12 and Table 4-13 of Chapter 4 of the Application.

BC Hydro notes that of the seven expected EPAs, as of October 2018, five are forecast to reach commercial operation during the test period and two are forecast to reach commercial operation beyond the test period.

Please refer to BC Hydro's response to ZONE II RPG IR 1.4.1 for a discussion of BC Hydro's approach to new supply in Non-Integrated Areas.

61.0 Topic: Chapter 5G. Operating Costs, Other Repurposing of Unallocated Funds

Reference: Application, Exhibit B-1, 5G.7.2 Overview of Operating Costs and FTEs; Exhibit B-6, BC Hydro Response to BCSEA IR 1.26.1

In response to BCSEA IR 1.26.1, BC Hydro states:

> "Yes, the re-purposing of the unallocated funds budget will, necessarily, have an impact on BC Hydro's ability to manage unanticipated costs pressures during the test period."

2.61.1 Has BC Hydro quantified the extent to which the re-purposing of unallocated funds will increase the risk of spending exceeding the approved revenue requirement during the test period? If so, what are the results? If not, why not?

RESPONSE:

As described in BC Hydro's response to BCUC IR 2.231.1, there will be significant challenges during the test period to manage within the total operating cost budget. As operating cost pressures resulting from unplanned work demands and unanticipated cost pressures are not known at this time, BC Hydro cannot quantify what this pressure will be.

62.0 Topic: Chapter 6. Capital Expenditures
Capital Expenditures

Reference: Exhibit B-6, BC Hydro Response to BCSEA IR 1.15.2; Exhibit B-5, BCUC 1.122.5

"BC Hydro anticipates collecting revenue from charging stations in fiscal 2020. BC Hydro intends to apply to the BCUC for approval of a rate design application for BC Hydro owned and operated EV Fast Charging Stations following the completion of the BCUC Inquiry into the Regulation of Electric Vehicle Charging Service, which is expected by fall 2019. BC Hydro anticipates collecting revenues from charging stations upon approval of the application." [Exhibit B-5, BCUC 1.122.5, underline added]

The Phase Two Report of the BCUC Inquiry into the Regulation of Electric Vehicle Charging Services was issued on June 24, 2019 (https://www.bcuc.com/Documents/Proceedings/2019/DOC_54345_BCUC%20EV%20Inquiry%20Phase%20Two%20Report-web.pdf).

2.62.1 What is the current status of BC Hydro's anticipated timing of an application to the BCUC for approval of a rate design for BC Hydro owned and operated EV Fast Charging Stations?

RESPONSE:

BC Hydro's application to the BCUC for approval of a rate for BC Hydro owned and operated EV fast charging stations should be informed by the Government of B.C.'s response to the recommendations to Government contained in the Phase Two Report of the BCUC Inquiry into the Regulation of Electric Vehicle Charging Service. The outcome of this inquiry directly affects the types and scope of the rates BC Hydro may put forward for approval in respect of public fast charging.

BC Hydro's current expectation is that the Government of B.C. will respond to the BCUC recommendations in fall 2019. Assuming this timeline, BC Hydro anticipates that a rate application for BC Hydro owned and operated EV fast charging stations would be filed with the BCUC in early 2020.

63.0 Topic: Chapter 10, Demand Side Management
DSM Envelope

Reference: Application, Exhibit B-1, Chapter 10, Demand Side Management; Exhibit B-6, BC Hydro Response to BCSEA IR 1.33.1

In its response to BCSEA IR 1.33.1, BC Hydro provided a table showing the traditional DSM expenditures on a plan and actual basis (where applicable) for fiscal 2017 to fiscal 2021. Actual figures for F2019 were not available at the time of the response.

2.63.1 Please provide an updated version of the table in response to BCSEA IR 1.33.1 that provides actual figures for F2019.

RESPONSE:

The table below updates the table in BC Hydro's response to BCSEA IR 1.33.1 to include fiscal 2019 actuals.

	Total Costs ($ million)		**Total Costs ($ million) Less TMP**	
	Plan	**Actual**	**Plan**	**Actual**
F2017	**113.7**	**97.4**	**113.7**	**97.3**
F2018	**119.5**	**82.3**	**104.8**	**84.2**
F2019	**127.9**	**104.2**	**100.7**	**76.4**
F2020	**90.8**	**TBD**	**90.8**	**TBD**
F2021	**116.2**	**TBD**	**89.1**	**TBD**

64.0 Topic: Chapter 10, Demand Side Management
Capacity-Focused DSM

Reference: Exhibit B-6, BC Hydro Response to BCSEA IR 1.39.2, 1.39.4

In its response to BCSEA IR 1.39.2, BC Hydro provides a table listing the capacity-focused solutions being tested at each of three substations: Pineview, Hope and Kent. The table also includes the expected relative savings contribution of each solution broken out by each identified constrained substation and customer sector. The table provides estimated Total Cumulative kW savings by the end of F2021 for each of the substations.

In its response to BCSEA IR 1.39.4, BC Hydro states:

> "Success with each capacity-focused DSM trial or pilot will be in the learning gained with regards to the capability to reliably shift and/or reduce load. This information will help to inform our ability to bundle capacity focused initiatives to defer upgrades at the local level or as resource options to inform the next Integrated Resource Plan.
>
> Beyond the trial or pilot stage, the success of capacity focused initiatives will be based on the ability to reliably shift or reduce loads at a lower cost than supply side resources and infrastructure." [pdf p.765]

2.64.1 Recognizing that the capacity-focused DSM measures being tested in the three substation areas are in the nature of a pilot, are the estimated total cumulative kW savings material in relation to the size of the capacity constraints at the three substations? If the estimated total cumulative kW savings were achieved would this be a material contribution toward deferring capital investments at these substations, or would substantially larger kW savings be required?

RESPONSE:

This answer also responds to BCSEA IR 2.64.2.

The substations were chosen to provide different opportunities for BC Hydro to learn about our ability to package a variety of initiatives that influence a range of different customers, in order to achieve capacity savings targets.

The estimated total cumulative kW savings targeted through the Pineview substation pilot during the test period would contribute to deferring capital investments.

The kW savings targeted through Kent substation feeder pilot during the test period would not be sufficient to defer capital investments.

At the Hope substation, there is an opportunity to achieve operational flexibility, however there is not an opportunity to defer capital investments. Additional kW savings beyond the test period for the Hope substation would add to this operational flexibility.

With both the Hope and Kent substations, BC Hydro will consider the potential to ramp up the kW savings after the test period. A decision to ramp up would be informed by what we learn through the substation pilots. BC Hydro will use the learnings from the pilots to better understand the additional kW savings that could be achieved beyond the test period.

64.0 Topic: Chapter 10, Demand Side Management
Capacity-Focused DSM

Reference: Exhibit B-6, BC Hydro Response to BCSEA IR 1.39.2, 1.39.4

In its response to BCSEA IR 1.39.2, BC Hydro provides a table listing the capacity-focused solutions being tested at each of three substations: Pineview, Hope and Kent. The table also includes the expected relative savings contribution of each solution broken out by each identified constrained substation and customer sector. The table provides estimated Total Cumulative kW savings by the end of F2021 for each of the substations.

In its response to BCSEA IR 1.39.4, BC Hydro states:

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>
> Beyond the trial or pilot stage, the success of capacity focused initiatives will be based on the ability to reliably shift or reduce loads at a lower cost than supply side resources and infrastructure." [pdf p.765]

2.64.2 If substantially larger kW savings would be required, how will BC Hydro assess whether such savings could be obtained through capacity-focused DSM?

RESPONSE:

Please refer to BC Hydro's response to BCSEA IR 2.64.1 where we explain that BC Hydro will use the learnings from the substation pilots during the test period to better understand the additional kW savings that could be achieved beyond the test period.

65.0 Topic: Chapter 10, Demand Side Management
Constrained Areas

Reference: Exhibit B-6, BC Hydro Response to BCSEA IR 1.39.3;
BC Hydro Net Metering Application, pp.42-43

In the context of Capacity-Focused DSM, BC Hydro identified the Pineview, Hope and Kent substations as constrained substation areas in which CFDSM measures are being tested.

In the 2019 Net Metering Application, BC Hydro states on pages 42-43 of the Application:

> "As explained in section 9.1.3 of the Evaluation Report, certain areas of the BC Hydro electrical grid are becoming constrained due to the number and size of generators injecting energy back into the grid. Additional generation at these locations, even from small projects in the Program, could require the replacement of substation transformers." [Underline added]

2.65.1 Is there any geographic overlap between areas that are constrained in terms of substation capacity and areas that are constrained in terms of injection of incremental generation?

RESPONSE:

Yes. This generally occurs in areas where there are large differences between the load profile and the generation profile during different seasons. For example, the Hope Substation is nearing capacity in terms of injection of incremental generation in the freshet period because hydro generation in the area is at maximum level and load is generally low. The Hope Substation is also nearing firm capacity in terms of serving incremental load during the winter because load in the area is high and generation in the area is low.

65.0 Topic: Chapter 10, Demand Side Management
Constrained Areas

Reference: Exhibit B-6, BC Hydro Response to BCSEA IR 1.39.3;
BC Hydro Net Metering Application, pp.42-43

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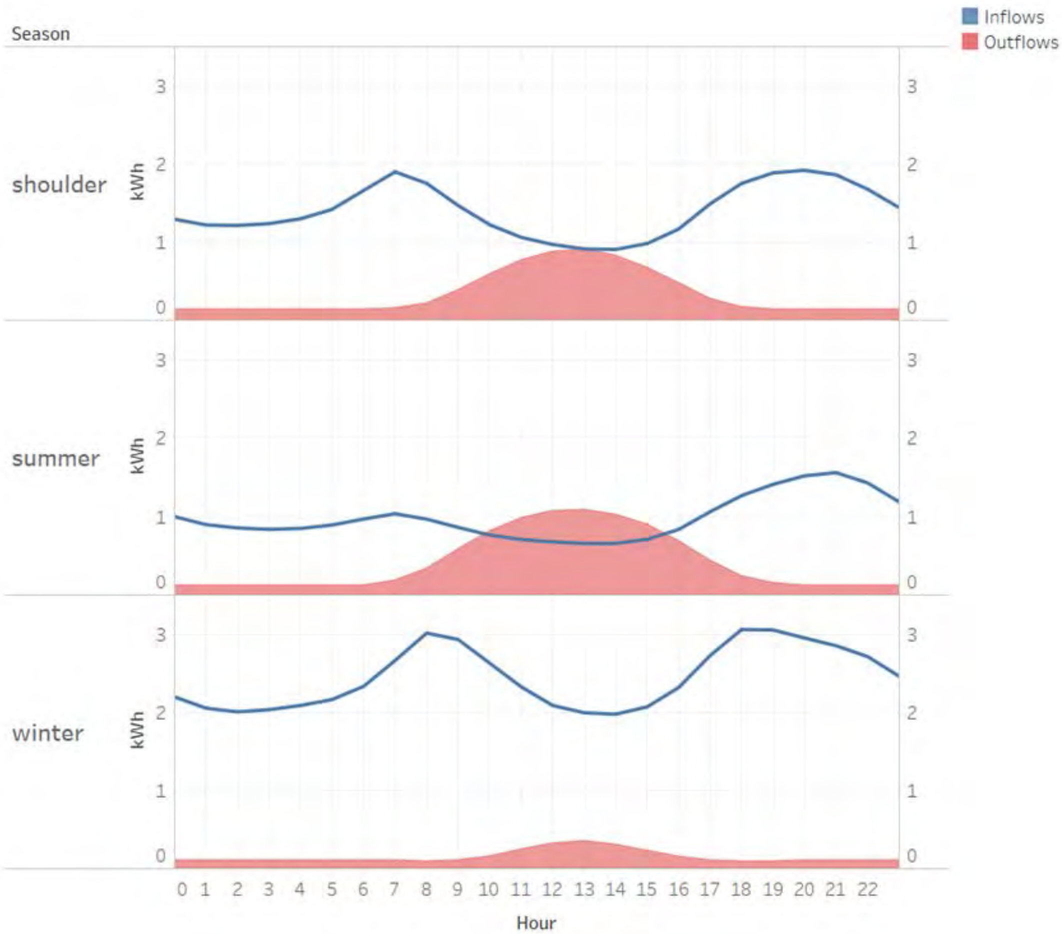
> "As explained in section 9.1.3 of the Evaluation Report, certain areas of the BC Hydro electrical grid are becoming constrained due to the number and size of generators injecting energy back into the grid. Additional generation at these locations, even from small projects in the Program, could require the replacement of substation transformers." [Underline added]

2.65.2 Are there circumstances in which new Net Metering installations could help to address capacity constraints at a particular substation?

RESPONSE:

It is unlikely that new Net Metering Program customers could help address substation load capacity constraints at this time. In order to provide capacity benefits, BC Hydro requires the generating resource to be reliably generating when needed which is typically during the system evening peak in the winter. More than 98 per cent of all customers in the Net Metering Program have solar photovoltaic generating facilities. These resources do not provide capacity benefits to address capacity constraints because they do not have generation in winter evenings. Net Metering installations may be able to provide some relief related to capacity constraints at a particular substation in some limited circumstances, but BC Hydro has not conducted an analysis to determine the viability of such an approach and the Program is not designed to address these issues.

The graphs below provide net consumption (inflow) and net generation (outflow) patterns, by season, for residential customers in the Net Metering Program, based on fiscal 2016 data.



Inflows
Outflows
Season
shoulder
summer
winter
kWh
0
1
2
3
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22
Hour

65.0 Topic: Chapter 10, Demand Side Management
Constrained Areas

Reference: Exhibit B-6, BC Hydro Response to BCSEA IR 1.39.3;
BC Hydro Net Metering Application, pp.42-43

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> "As explained in section 9.1.3 of the Evaluation Report, certain areas of the BC Hydro electrical grid are becoming constrained due to the number and size of generators injecting energy back into the grid. Additional generation at these locations, even from small projects in the Program, could require the replacement of substation transformers." [Underline added]

2.65.3 With reference to the list of Trials and Pilots in the Capacity-Focused DSM program [Exhibit B-5, BCUC 1.183.1, p.3], has BC Hydro considered Net Metering as a potential measure to address local capacity constraints?

RESPONSE:

No. Please refer to BC Hydro's response to BCSEA IR 2.65.2 where we explain why Net Metering customers are unlikely to be suitable for addressing substation load capacity constraints at this time.

66.0 Topic: Chapter 10, Demand Side Management
Capacity-Focused DSM

Reference: Application, Exhibit B-1; Exhibit B-6, BC Hydro Response to BCSEA IR 1.38.3; Exhibit B-5, BCUC 1.183.2, p.3

"BC Hydro expects the results of its capacity-focused DSM pilots and trials to inform the resource options that are considered in the next Integrated Resource Plan." [Exhibit B-6, BCSEA 1.38.3]

"The results of the CFDSM activities will inform the next Integrated Resource Plan, which in turn will guide BC Hydro's actions with respect to capacity and energy deficits." [Exhibit B-5, BCUC 1.183.2, p.3]

2.66.1 When does BC Hydro expect to commence consultation regarding the resource option report that will inform the 2021 Integrated Resource Plan?

RESPONSE:

BC Hydro expects to commence consultation in the fall of 2019 regarding the resource option report that will inform the 2021 Integrated Resource Plan.

67.0 Topic: Chapter 10, Demand Side Management
Capacity-Focused DSM

Reference: Application, Exhibit B-1; Exhibit B-6, BC Hydro Response to BCSEA IR 1.39.5.1; Exhibit B-5, BC Hydro Response to BCUC 1.183.2

In response to BCSEA IR 1.39.5.1, BC Hydro states:

> "No, the reduced budget will not impact our ability to test and analyze opportunities [to use capacity-focused DSM to reduce infrastructure investments]. The budget reflects the expenditures needed to implement our capacity-focused DSM activities and is not constraining BC Hydro during the test period.
>
> Please refer to BC Hydro's response to BCUC IR 1.183.2 where we explain the reductions and shift in timing of our capacity-focused DSM expenditures."

2.67.1 Will the results of BC Hydro's capacity-focused DSM trials and pilots be available in time to be fully included in the resource options report that will be used for the 2021 Integrated Resource Plan?

RESPONSE:

We anticipate that, although all the pilots may not be completed, we will have either final or interim results that will provide valuable insights into the potential of capacity-focused DSM and help to inform the resource options in the next Integrated Resource Plan.

67.0 Topic: Chapter 10, Demand Side Management
Capacity-Focused DSM

Reference: Application, Exhibit B-1; Exhibit B-6, BC Hydro Response to BCSEA IR 1.39.5.1; Exhibit B-5, BC Hydro Response to BCUC 1.183.2

In response to BCSEA IR 1.39.5.1, BC Hydro states:

> "No, the reduced budget will not impact our ability to test and analyze opportunities [to use capacity-focused DSM to reduce infrastructure investments]. The budget reflects the expenditures needed to implement our capacity-focused DSM activities and is not constraining BC Hydro during the test period.
>
> Please refer to BC Hydro's response to BCUC IR 1.183.2 where we explain the reductions and shift in timing of our capacity-focused DSM expenditures."

2.67.2 Would a larger budget for capacity-focused DSM during the test period produce more useful results sooner than the proposed budget?

RESPONSE:

With the existing budget for the Test Period, BC Hydro has established a prudent and measured approach to testing out the various technologies and activities that form capacity-focused DSM. Within this budget, we have also selected multiple substation pilots to test out combinations of technologies and activities to determine whether a constraint target can be met.

Given the long lead times associated with developing, launching and implementing capacity-focused DSM pilots, it is not clear whether a larger budget during the test period would provide more useful results sooner.

68.0 Topic: Chapter 10, Demand Side Management
Capacity-Focused DSM

Reference: Application, Exhibit B-1; Exhibit B-5, BC Hydro Response to BCUC 1.183.1, page 6 of 9

In describing the Key Findings of its Capacity-Focused DSM trials and pilots, BC Hydro states:

> "Baselines, which enable the comparison between what would have happened, absent the program intervention and what actually happened, can be complicated. They need to be clearly defined and consider the customer's operational behaviour and technology available."

2.68.1 Has BC Hydro considered using control groups to help evaluate the effectiveness of the various capacity-focused DSM measures? If so, would this require regulatory approval? If not, why not?

RESPONSE:

BC Hydro considers the use of controls groups to help assess the effectiveness of various DSM initiatives. For example, non-participant control groups are frequently used in the evaluation of DSM programs.

BC Hydro also considers the use of control groups and participant baselines to better understand capacity-focused DSM initiatives where appropriate.

Specific regulatory approval is not required for the use of control groups to help evaluate capacity focused DSM measures, although BC Hydro requires acceptance of any associated DSM expenditures under section 44.2 of the *Utilities Commission Act*.

69.0 Topic: Chapter 10, Demand Side Management Capacity-Focused DSM

Reference: Exhibit B-5, BC Hydro Response to BCUC 1.183.1, Attachment 1, pdf p.2032

"Smart electric vehicle (EV) charging – single family

- Status: Initiated in May 2017, completed.
- Description: The project involved EV owners in single family residential settings. Communicating level 2 electric vehicle supply equipment (EVSE) or charging stations replaced existing level 2 stations installed in each home. This allowed for signals to be sent to the EVSE to enact various smart charging tactics such as randomization of charging times, charge-by settings, decreased power charging etc.
- Results: 50 single family residences participated in the pilot that ran over two winters (fiscal 2018 and fiscal 2019). Preliminary results will be available later in 2019." [underline added]

2.69.1 Please provide (or summarize) the preliminary results of the "Smart electric vehicle (EV) charging – single family" project if they are available.

RESPONSE:

The preliminary results and findings from the Smart Electric Vehicle Charging – Single Family Project are as follows:

- **The smart charger performed according to its specifications and responded to curtailment events as required;**
- **Demand response in the morning showed limited results which is due to vehicles being unplugged during the morning test period. Evening curtailment events worked very well because that is the time most vehicles were plugged in. Vehicles were plugged in for more than ten hours but only required between one and four hours to fully charge;**
- **Electric vehicles with the "minimum state of charge" feature provided lower benefits when the feature was enabled. The feature prevented curtailment when vehicles were low on charge and therefore reduced the demand response benefits;**
- **Participant survey results indicate few program participants were negatively impacted by the demand response events. This is supported by the fact that**

there were a small number of participants who took advantage of the opt-out option provided; and

- **The survey results also showed that participants were likely to participate in future demand response programs provided some kind of financial incentive was provided and the opt-out option was available.**

BC Hydro's preliminary conclusions are as follows:

- **Vehicles generally need between one to four hours of charging overnight, but are plugged in for eight to 10 hours on average. This means there is substantial load flexibility. Actual kW and duration is variable depending on factors such as the type of electric vehicle, vehicle state of charge and driver behaviour;**
- **Average capacity savings is estimated to be 1 kW/vehicle across the broad spectrum of brands, during peak hours, while factoring in opt-out activity and cars that may not plug in every evening. The assumption is these are battery electric vehicles. Hybrids charge much less and are not included in the calculations;**
- **Participants found the events non-disruptive and the events did not increase "range anxiety" or "charge anxiety"; and**
- **Participants liked the additional reporting, charging time, and increased control the smart charging station provided.**

70.0 Topic: Chapter 10, Demand Side Management
Capacity-Focused DSM

Reference: Exhibit B-5, BC Hydro Response to BCUC 1.183.1, Attachment 1, pdf p.2032; Phase Two Report, BCUC Inquiry into the Regulation of Electric Vehicle Charging Services (https://www.bcuc.com/Documents/Proceedings/2019/DOC_54345_BCUC%20EV%20Inquiry%20Phase%20Two%20Report-web.pdf), pp. 30-31; BCUC Order G-92-19 (https://www.ordersdecisions.bcuc.com/bcuc/orders/en/400728/1/document.do)

"High voltage utility charger – MURB and Commercial customers

• Status: Launched September 2017, ongoing.

• Description: Current challenges for potential EV owners who live in multi-unit residential buildings include charger and related infrastructure costs as well as the need to disaggregate metered electricity consumption between EV charging and the building's common facilities (i.e., non-EV loads). An integrated charger, and a metering and billing solution would potentially alleviate these concerns. We will be testing the ability to control the timing of the charge.

• Results: Plan is to install 60 chargers in locations in the Lower Mainland. Roll out has been delayed due to testing. Expectations are the pilot will run during the winter of 2019 with results being available later in 2020."

The June 24, 2019 Phase Two Report of the BCUC's Inquiry into the Regulation of Electric Vehicle Charging Services refers to an April 29, 2019 BCUC Order G-92-19 that the Panel describes as follows:

"A recent example of this participation [by a non-exempt public utility in facilitating the development of EV charging infrastructure in strata and rental properties] is BCUC Order G-92-19 that approved amendments to the residential tariff to allow for the electricity metering of parking stalls in a MURB and combining the bill with that of the parking stall owner's dwelling unit, thereby eliminating the separate basic charge for the parking stall's electric meter."

2.70.1 Is BCUC Order G-92-19 related to BC Hydro's "High voltage utility charger – MURB and Commercial customers" pilot?

RESPONSE:

The changes to the Electric Tariff approved by BCUC Order No. G-92-19 are related to one component of the "High voltage utility charger – MURB and Commercial customers" pilot.

The purpose of the "High voltage utility charger – MURB and Commercial customers" pilot is to address current challenges for potential electric vehicle (EV) charging in multi-unit residential buildings or commercial buildings. There are two components to the pilot:

- **The main component focused on the development of a charger with an integrated transformer, which is intended to reduce EV charging infrastructure costs. This component is not related to the changes to the Electric Tariff approved by BCUC Order No. G-92-19; and**
- **An additional component focused on a solution for metering energy consumption for EV charging separately from a building's common area (i.e., non-EV loads) within multi-unit residential buildings. The changes to the Electric Tariff approved by BCUC Order No. G-92-19 relate to this component. The amended Tariff provisions allow BC Hydro to install multiple meters at a dwelling (as that term is amended and defined in the Tariff) at the customer's request, to aggregate the energy consumption from multiple meters, and to bill the customer for the aggregated consumption under one Residential Service account.**

70.0 Topic: Chapter 10, Demand Side Management
Capacity-Focused DSM

Reference: Exhibit B-5, BC Hydro Response to BCUC 1.183.1, Attachment 1, pdf p.2032; Phase Two Report, BCUC Inquiry into the Regulation of Electric Vehicle Charging Services (https://www.bcuc.com/Documents/Proceedings/2019/DOC_54345_BCUC%20EV%20Inquiry%20Phase%20Two%20Report-web.pdf), pp. 30-31; BCUC Order G-92-19 (https://www.ordersdecisions.bcuc.com/bcuc/orders/en/400728/1/document.do)

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- Results: Plan is to install 60 chargers in locations in the Lower Mainland. Roll out has been delayed due to testing. Expectations are the pilot will run during the winter of 2019 with results being available later in 2020."

The June 24, 2019 Phase Two Report of the BCUC's Inquiry into the Regulation of Electric Vehicle Charging Services refers to an April 29, 2019 BCUC Order G-92-19 that the Panel describes as follows:

> "A recent example of this participation [by a non-exempt public utility in facilitating the development of EV charging infrastructure in strata and rental properties] is BCUC Order G-92-19 that approved amendments to the residential tariff to allow for the electricity metering of parking stalls in a MURB and combining the bill with that of the parking stall owner's dwelling unit, thereby eliminating the separate basic charge for the parking stall's electric meter."

2.70.2 What plans does BC Hydro have to inform owners and residents of strata and rental properties of the new potential billing arrangements enabled by Order G-92-19?

RESPONSE:

The following steps are being taken to inform owners and residents of strata and rental properties of the new potential metering and billing arrangements enabled by BCUC Order No. G-92-19:

- **Updating internal processes, procedures and providing training to frontline staff (e.g., the Distribution Design and Customer Connect KBU and the Customer Service KBU) to explain the new metering and billing options available to customers taking Residential Service who contact BC Hydro for electric vehicle charging connection requests;**
- **Updating BC Hydro's external website, www.bchydro.com/ev to provide information on the new metering and billing options; and**
- **Communicating the new metering and billing options to industry associations who promote and install electric vehicle charging.**

71.0 Topic: Chapter 10, Demand Side Management
Capacity-Focused DSM

Reference: Application, Exhibit B-1; Exhibit B-5, BC Hydro Response to BCUC 1.183.1

BC Hydro reports on its exploration of localized demand-side management to defer local transmission and distribution investments.

2.71.1 Does BC Hydro anticipate that localized demand-side management measures will require specific regulatory approval to do with the fact that the measures are not available to ratepayers outside the local target area?

RESPONSE:

The only specific regulatory approval required for localized demand-side management measures will be acceptance of the DSM expenditures pursuant to section 44.2 of the *Utilities Commission Act*. Demand-side measures are typically designed to be available to particular groups of customers in order to achieve particular benefits or overcome particular barriers. The fact that localized DSM measures will be available only in a target area enables them to defer local transmission and distribution infrastructure. This results in a reduction to BC Hydro's overall revenue requirement, which should support a determination by the BCUC that they are in the public interest.

71.0 Topic: Chapter 10, Demand Side Management
Capacity-Focused DSM

Reference: Application, Exhibit B-1; Exhibit B-5, BC Hydro Response to BCUC 1.183.1

BC Hydro reports on its exploration of localized demand-side management to defer local transmission and distribution investments.

2.71.2 Does BC Hydro anticipate any difficulty with customer acceptance of localized DSM measures?

RESPONSE:

This answer also responds to BCSEA IR 2.71.3.

BC Hydro has extensive experience delivering energy efficiency initiatives for residential, commercial, and industrial customers through our existing DSM programs. BC Hydro first identifies the barriers that prevent adoption. Categories of barriers are: awareness, acceptance, availability, accessibility and affordability. BC Hydro then designs the DSM initiative to address the identified barriers.

BC Hydro does anticipate that there may be difficulty with customer acceptance of localized DSM measures. BC Hydro believes that it will be important that capacity focused DSM measures are not disruptive to customers in order to minimize customer acceptance issues. Many of BC Hydro’s capacity focused DSM pilot initiatives are designed to better understand customer satisfaction and potential areas of customer disruption to inform future program design.

To overcome potential customer acceptance issues, BC Hydro expects that the use of information and education, allowing customers to maintain some element of control and minimizing inconvenience to customers will all be important strategies.

71.0 Topic: Chapter 10, Demand Side Management
Capacity-Focused DSM

Reference: Application, Exhibit B-1; Exhibit B-5, BC Hydro Response to BCUC 1.183.1

BC Hydro reports on its exploration of localized demand-side management to defer local transmission and distribution investments.

2.71.3 If yes, what steps will BC Hydro undertake to overcome those objections?

RESPONSE:

Please refer to BC Hydro's response to BCSEA IR 2.71.2 where we discuss the steps that BC Hydro undertakes to overcome acceptance barriers.

72.0 Topic: Chapter 10, Demand Side Management
Capacity-Focused DSM

Reference: Exhibit B-5, BC Hydro Response to BCUC 1.183.1, pages 8-9 of 9; Exhibit B-5, BC Hydro Response to BCUC 1.183.3; Exhibit B-6, BC Hydro Response to BCSEA 1.38.3; Exhibit B-6, BC Hydro Response to BCSEA 1.39.4

“The pilots are providing information that will inform the savings potential and cost effectiveness of different technologies and behaviours. The results are based on smaller scale pilots that may not translate to broader populations. Information from the pilots will be used to inform potential opportunities at the distribution system level as well as broader potential resource options to inform the next Integrated Resource Plan.” [Exhibit B-5, BC Hydro Response to BCUC 1.183.1, pages 8-9 of 9]

“Continuation and completion of planned trials, as well as further experience gained through localized capacity initiatives at the substation. level (combined with DERMS development), are the next steps prior to estimating potential program savings...” [Exhibit B-5, BC Hydro Response to BCUC 1.183.3]

“BC Hydro expects the results of its capacity-focused DSM pilots and trials to inform the resource options that are considered in the next Integrated Resource Plan.” [Exhibit B-6, BC Hydro Response to BCSEA 1.38.3]

“Success with each capacity-focused DSM trial or pilot will be in the learning gained with regards to the capability to reliably shift and/or reduce load. This information will help to inform our ability to bundle capacity focused initiatives to defer upgrades at the local level or as resource options to inform the next Integrated Resource Plan. [Exhibit B-6, BC Hydro Response to BCSEA 1.39.4]

Beyond the trial or pilot stage, the success of capacity focused initiatives will be based on the ability to reliably shift or reduce loads at a lower cost than supply side resources and infrastructure.” [Exhibit B-6, BC Hydro Response to BCSEA 1.39.4]

2.72.1 Please outline the various next steps and the associated timing that BC Hydro anticipates will come out of the capacity-focused DSM activity during the test period.

RESPONSE:

We anticipate that the majority of technical trials will have been completed by the end of the Test Period. This work will include assessments and summaries of findings to inform potential future program development in this area.

In parallel to the work that is underway to complete the remaining technical trials, work will commence on resource option development for the next Integrated Resource Plan, including capacity-focussed DSM options. We anticipate that the Integrated Resource Plan resource option development will start in the fall of 2019 and will complete in the spring of 2020. We expect that the work to develop the Integrated Resource Plan resource options will be informed by the Conservation Potential Review, as well as the findings of the capacity-focussed DSM trials and pilots, where applicable.

These resource options will be used in the Integrated Resource Plan analysis, which will inform the development of a recommended action plan, including potential actions related to capacity-focussed DSM. The Integrated Resource Plan is planned to be submitted to the BCUC in February 2021.

73.0 Topic: Chapter 10, Demand Side Management
Demand-Side Management Plan Evolution

Reference: Exhibit B-6, BC Hydro Response to BCSEA 1.43.1

Asked to discuss the implications of reducing the commercial and industrial programs budgets in terms of expected savings and participants, BC Hydro states:

> "BC Hydro expects energy savings in the commercial sector to be lower due to lower expected participation in incentive projects. BC Hydro expects energy savings in the industrial sector to be higher due to similar participation in incentive projects and increased energy savings through energy management activities.
>
> During the process of updating the DSM plan, BC Hydro considered a number of factors, including participation projections, technology costs, energy management activities, and customer barriers. BC Hydro's projections of commercial sector participants forecast to submit incentive projects over the test period was lower than previously planned. As a result, BC Hydro was able to reduce the expenditures to reflect the updated expectations of commercial sector participation over the test period. In addition, of those projects submitted, lower incentives will be required due to lower technology costs, the mix of projects, and an increase in customer funded projects.
>
> In the industrial sector, BC Hydro expects energy management activities to assist in achieving additional energy savings." [underline added]

2.73.1 In BC Hydro's view, why were its projections of commercial sector participants forecast to submit incentive projects over the test period lower than previously planned? Does this represent a 'vicious circle' in which future reductions in spending on commercial DSM programs results in fewer proposals for commercial DSM projects?

RESPONSE:

BC Hydro made changes to the commercial program offers as part of the moderation strategy as outlined in the Previous Application. When program changes are made and announced, there is some uncertainty on how the market will react to the changes. Although BC Hydro assessed what impacts the program changes may have on program participation in its forecast of expenditures, the

commercial program changes resulted in lower participation and expenditures than BC Hydro estimated in its DSM plan in the Previous Application.

Since the program changes were introduced and the market has had time to adapt to the revised offers, we have reassessed the response and have a better understanding of expected project forecasts which we have reflected in this Application. We do not anticipate a continued decline in participation.

74.0 Topic: Chapter 10, Demand Side Management
DSM Evaluation, Measurement and Verification

Reference: Application, Exhibit B-1, Appendix AA, DSM Measurement, Verification and Evaluation; Appendix AA, Attachment 1, F2017 Demand Side Management Milestone Evaluation Summary Report

In Attachment 1 of Appendix AA [pdf p.2296], BC Hydro provides a copy of its F2017 Demand Side Management Milestone Evaluation Summary Report, dated December 2017. 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.

2.74.1 Is BC Hydro concerned about the lag between the date of the data and the date of the reports of the impact evaluations?

RESPONSE:

This answer also responds to BCSEA IR 2.74.2.

BC Hydro is not concerned with the lag between the date of the data and the date of the reports of the impact evaluations.

BC Hydro tracks program performance, market trends and customer satisfaction (e.g., customer surveys, market information, site inspections, Measurement & Verification) at more frequent intervals than impact evaluations to provide regular feedback to program managers on program performance.

In addition, as noted in BC Hydro's response to BCUC IR 2.271.1.2, BC Hydro has developed criteria to determine its evaluation workplan, which provides guidance for the evaluation frequency and coverage of DSM initiatives. The evaluation planning criteria are designed to balance the value from the evaluations with the costs and resources required to conduct them.

While a more recent impact evaluation report for the Commercial New Construction program is not available at this time, one is planned for fiscal 2020, as noted in BC Hydro's response to BCOAPO IR 2.158.1. The Commercial New Construction program is challenging to evaluate as frequently as other programs due to factors such as construction, occupancy and the time required to obtain measurement and verification results.

74.0 Topic: Chapter 10, Demand Side Management
DSM Evaluation, Measurement and Verification

Reference: Application, Exhibit B-1, Appendix AA, DSM Measurement, Verification and Evaluation; Appendix AA, Attachment 1, F2017 Demand Side Management Milestone Evaluation Summary Report

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2. Continuous Optimization: F2011-F2013;
3. High Performance Buildings and Commercial New Construction: F2008-F2011; and
4. Power Smart Partner - Transmission: F2012-F2014.

2.74.2 For Commercial New Construction, can BC Hydro provide an impact evaluation of data that is more recent than F2008-F2011?

In Appendix AA, pdf pp.2288-2289, BC Hydro provides an evaluation work plan for the test years (F2020 and F2021) that includes the list of planned evaluations and various data collection activities that provide inputs to evaluations.

RESPONSE:

Please refer to BC Hydro’s response to BCSEA IR 2.74.1, where we explain when the next Commercial New Construction program evaluation will be available.

74.0 Topic: Chapter 10, Demand Side Management
DSM Evaluation, Measurement and Verification

Reference: Application, Exhibit B-1, Appendix AA, DSM Measurement, Verification and Evaluation; Appendix AA, Attachment 1, F2017 Demand Side Management Milestone Evaluation Summary Report

In Attachment 1 of Appendix AA [pdf p.2296], BC Hydro provides a copy of its F2017 Demand Side Management Milestone Evaluation Summary Report, dated December 2017. The Report summarizes the impact evaluations completed during F2017 for the following:

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2. Continuous Optimization: F2011-F2013;
3. High Performance Buildings and Commercial New Construction: F2008-F2011; and
4. Power Smart Partner - Transmission: F2012-F2014.

2.74.3 For the impact evaluations and process evaluations slated for F2020, when and in what form will the results be provided?

RESPONSE:

Directive 66 of the BCUC's Decision on BC Hydro's 2004/05 to 2005/06 Revenue Requirements Application directed BC Hydro to file the executive summaries of its milestone evaluation reports and full final evaluation reports for all its DSM programs. BC Hydro meets this requirement through filing annual Evaluation Summary Reports with the BCUC, typically later in the following fiscal year. Accordingly, for the impact evaluations and process evaluations scheduled to complete in fiscal 2020, an annual Evaluation Summary Report for fiscal 2020 will be filed with the BCUC later in fiscal 2021.

In addition to these annual filings, BC Hydro also appends its most recent Evaluation Summary Reports to Revenue Requirements Applications, to inform the BCUC's consideration of its DSM expenditure request.

75.0 Topic: Chapter 10, Demand Side Management
CleanBC Better Buildings Program

Reference: Application, Exhibit B-1, section 10.4.3 re Energy EfficiencyBC program funding for LCE, pdf 1052; Exhibit B-6, BC Hydro Response to BCSEA IR 55.2 (Energy EfficiencyBC funding for low carbon electrification initiatives)

2.75.1 Please confirm, or otherwise explain, that the estimated $12.3 million allocated to BC Hydro to implement offers to fuel switch to electricity is the full extent of the Better Buildings program budget that is administered by BC Hydro. That is, it is not the case the BC Hydro administers some aspects of the Better Buildings program that do not involve fuel-switching to electricity.

RESPONSE:

The $12.3 million was the initial allocation going to BC Hydro for the EfficiencyBC program which subsequently became CleanBC Better Homes and Better Buildings. Subsequent to this initial arrangement, BC Hydro has now been asked to administer a government funded commercial new construction fuel switching initiative that will increase this value over time. BC Hydro also expects the initial allocation of $12.3 million could increase over time if the Government of B.C. extends the time period for their initial offers or asks BC Hydro to administer new potential offers.

In addition to these fuel switching offers, BC Hydro has been asked to process energy efficiency CleanBC Better Homes program incentives for windows, doors, or insulation projects with customers whose primary space heating fuel is natural gas from Pacific Northern Gas, oil, or propane (not from FortisBC piped propane). These are expected to be a small component of the overall CleanBC Better Homes and Better Buildings program and are government funded.

75.0 Topic: Chapter 10, Demand Side Management
CleanBC Better Buildings Program

Reference: Application, Exhibit B-1, section 10.4.3 re Energy EfficiencyBC program funding for LCE, pdf 1052; Exhibit B-6, BC Hydro Response to BCSEA IR 55.2 (Energy EfficiencyBC funding for low carbon electrification initiatives)

2.75.2 Who administers the portion of the Better Buildings budget that is not administered by BC Hydro? Is it FortisBC Energy Inc., or FortisBC Inc. (electric)?

RESPONSE:

This response also provides BC Hydro's response to BCSEA IR 2.75.3.

BC Hydro is aware of the following groups that are involved in the administration of the CleanBC Better Homes and Better Buildings budget that is not administered by BC Hydro: FortisBC Energy Inc. (FortisBC Gas), FortisBC Inc. (FortisBC Electric), and BC Housing. BC Hydro works collaboratively with all partners to ensure a smooth experience for the customer.

The following list explains how the administration responsibilities for the CleanBC Better Homes and Better Buildings program are divided between BC Hydro and the other entities:

- **Fuel switching customers in the BC Hydro service territory and the City of New Westminster are administered by BC Hydro;**
- **Fuel switching customers in FortisBC Electric service territory are administered by FortisBC Electric;**
- **Gas efficiency customers in FortisBC Gas territory are administered by FortisBC Gas;**
- **Residential gas efficiency customers for windows, doors, and insulation whose primary space heating fuel is from Pacific Northern Gas are administered by BC Hydro;**
- **Residential propane or oil space heated customers (excluding FortisBC piped propane customers) for windows, doors, and insulation energy efficiency projects are administered by BC Hydro; and**
- **Across all service territories, BC Housing administers CleanBC Better Buildings in the non-profit and social housing sector.**

75.0 Topic: **Chapter 10, Demand Side Management**
CleanBC Better Buildings Program

Reference: **Application, Exhibit B-1, section 10.4.3 re Energy EfficiencyBC program funding for LCE, pdf 1052; Exhibit B-6, BC Hydro Response to BCSEA IR 55.2 (Energy EfficiencyBC funding for low carbon electrification initiatives)**

2.75.3 Please explain how the administration responsibilities for the Better Buildings program are divided between BC Hydro and the other entity(ies). Does BC Hydro administer all Better Buildings measures that occur within BC Hydro's service territory, and none that occur outside its service territory? In what circumstances, if any, would an entity other than BC Hydro administer a Better Buildings measure that occurs within BC Hydro's service territory.

RESPONSE:

Please refer to the BC Hydro response to BCSEA IR 2.75.2

75.0 Topic: **Chapter 10, Demand Side Management**
CleanBC Better Buildings Program

Reference: **Application, Exhibit B-1, section 10.4.3 re Energy EfficiencyBC program funding for LCE, pdf 1052; Exhibit B-6, BC Hydro Response to BCSEA IR 55.2 (Energy EfficiencyBC funding for low carbon electrification initiatives)**

2.75.4 Please provide a table showing each of the measures supported by Better Buildings, the entity or entities that administers each the measure, and where more than one entity administers a measure the criteria for determining which entity administers the measure. If possible, please provide the approximately budget allocation.

RESPONSE:

Please refer to BC Hydro's response to BCSEA IR 2.75.2 to clarify which entity administers in which situation. As outlined in that response, BC Hydro works collaboratively with the partners to ensure a smooth experience for the customer.

The following table outlines the measures that BC Hydro administers for CleanBC Better Home and Better Buildings.

Residential
Fuel Switch: Air source heat pump- mini split
Fuel Switch: Air source heat pump- multi split
Fuel Switch: Air source heat pump- central no fossil fuel back-up
Fuel Switch: Air source heat pump- central with fossil fuel back-up
Fuel Switch: Air source heat pump water heater
Fuel Switch: Custom heat pump (e.g. hydronic, combined with water heater etc.)
Windows, Doors, or Insulation upgrades (energy efficiency) for customers whose primary space heating fuel is natural gas from Pacific Northern Gas, oil, or propane (other than FortisBC piped propane)
Energy Assessments
Upgrade Bonus (installing multiple measures)
Commercial
Energy studies investigating custom fuel switching retrofits
Custom fuel switching retrofit implementation
Energy studies investigating commercial new construction fuel switching
Commercial new construction project implementation fuel switching

FortisBC Inc. supports these same fuel switching measures in their service territory with the exception of the fuel switching commercial new construction offers. While not listed specifically in the table above, FortisBC Energy Inc. supports gas efficiency measures and BC Housing supports fuel switching measures in their respective areas of responsibility.

The following websites outline the CleanBC offers and many of the utilities' efficiency offers:

https://betterhomesbc.ca/

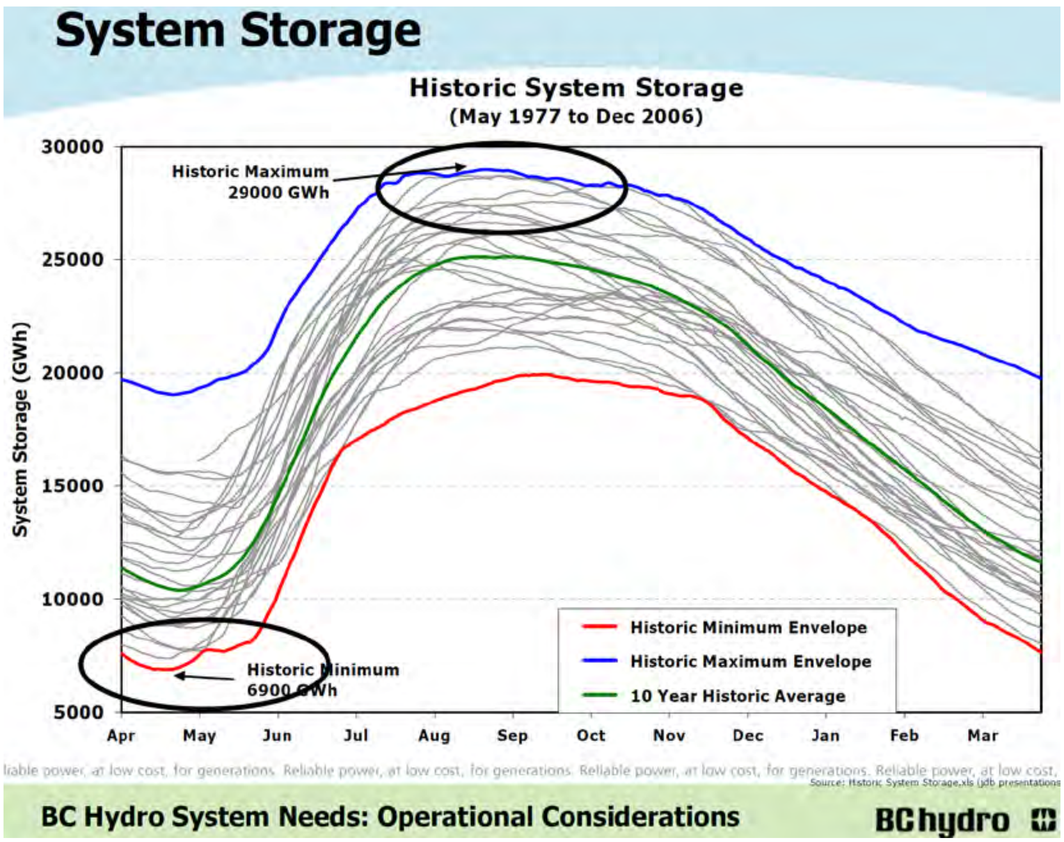
https://betterbuildingsbc.ca/

https://betterbuildingsbc.ca/incentives/cleanbc-social-housing-incentives/

The Government of B.C. or the applicable entity would be best suited to answer questions about their areas of responsibility.

25.0 Reference: Exhibit B-1, the Application, Section 4.4, discussing the use of System Storage to optimize the value of BC Hydro's energy, and the history of System Storage.

In Table 4-1 (page 4-18), BC Hydro reported the recent history of its year-end System Storage levels. In a 2007 Workshop, BC Hydro presented the following chart showing the monthly history of its System Storage going back to 1977.



2.25.1 Please update this historic data by providing a table of the month-end System Storage levels from January, 2007 to the end of March, 2019, in a working Excel model.

RESPONSE:

This response includes commercially sensitive information which has been redacted in the public version of the response. The un-redacted version of the response contains information about BC Hydro's monthly System Storage energy content. Publication of the information would enable third-parties to model

BC Hydro's system to predict BC Hydro's import and export requirements. Given the high degree of sensitivity around these numbers, and the significant potential for harm that would result from inadvertent disclosure, the un-redacted version of this response is being made available to the BCUC only.

The table below provides month-end System Storage levels from January 2007 to the end of March 2019 in GWh.

[redacted]

26.0 Reference: Exhibit B-1, the Application, Section 4.4.2 discussing BC Hydro's Energy Study methodology, and Section 4.4, discussing the use of System Storage to optimize the value of BC Hydro's energy.

In the Summary Notes to the October 11, 2018 Transmission Service Rate Design Workshop, BC Hydro reported that *"the surplus energy volume from most recent fiscal year (F2018) was just over 5,000 GWh."* (statement highlighted in the Summary Notes below)

2.	**Lok Chao Liu, Yotta Technologies Inc.** **Question** - Wanted clarification on the size of the surplus and the contribution of industrial load to total domestic load. He referred back to Keith Anderson's (page 7 slide) where the annual consumption for industrials was 16,000 GWh/yr and is now ~ 13,500 GWh/yr. **Question** - Wanted clarification on BCH's installed generation capacity and current system peaks. **Question** – Why are Manitoba Hydro rates lower than BCH's? **Question** – What is the scale/size of the surplus? Like a thousand megawatts?	The industrial customer portion of BCH's total domestic load, by energy volume, is about 25 per cent. BCH has about 11,000 MW of installed generation, the majority of which is large hydro. In terms of peak demand, BCH is a winter peaking utility although summer peaks (due to AC loads) have been increasing. Peak loads occur during heavy load hours (typically 4 p.m. to 8 p.m.) on cold winter nights. Subject to check, peak domestic loads are ~ 8,500 MW*. ***Updated Response:** • Peak Winter demand: 10,200 MW

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	Feedback	BC Hydro Response
		• Peak Summer demand: 7,500 MW Confirmed that Manitoba Hydro's rates are currently lower than BCH's. The energy surplus varies from year to year and on a planning basis vs actual basis. Forecast is based on average water. Actual depends on system conditions - which are highly variable. For context, the surplus energy volume from most recent fiscal year (F2018) was just over 5,000 GWh.

In Section 4.4.4 of the Application, BC Hydro's System Storage is defined as follows:

"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."

Table 4-1 (page 4-18) reports the year-end System Storage quantities, in GWh, as follows:

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

From this BC Hydro evidence, it appears that, even though there was an apparent 5,000 GWh surplus of energy in the fiscal year 2018, BC Hydro chose to run down its reservoir levels by 3,500 GWh compared to the levels at the start of F2018 (the highlighted values show 13,208 GWh at the end of F2017 vs. 9,736 GWh at the end of F2018, a drop of approximately 3,500 GWh).

2.26.1 What does BC Hydro consider to be the normal target level for System Storage at the end of a fiscal year (i.e. the end of March each year)? What level is considered lower than desirable? What level is considered excessively high?

RESPONSE:

BC Hydro does not have a target level for system storage for the end of a fiscal year. Instead, BC Hydro's objective is to maximize the value of our energy supply. The desirable level for system storage at the end of the fiscal will depend on a number of factors that are inputs to the Energy Study and have been outlined in section 4.4.2.1 of Chapter 4 of the Application (load, IPP supply, inflows, electricity and gas market prices, generation unit availability).

Storage levels at the end of a fiscal year will be driven by two main factors:

1. **The actual operations that materialize across the year. As an example, if system loads are exceptionally high due to colder than normal winter temperatures, then the system will show a tendency toward lower system storage levels; and**

2. **The forecast for future operational factors (load, IPP supply, inflows, electricity and gas market prices, generation unit availability). As an example, in the case where there is high snowpack in the system storage reservoir basins (high forecasted freshet inflows), then with all else being equal, the Energy Studies Model will provide guidance that will result in a tendency**

toward a deeper draft of system storage. The deeper projected draft would more effectively capture the forecast additional freshet inflow and store the water until high value time periods. Conversely if low freshet flows are being forecasted, then with all else being equal, there would be a tendency toward a higher system storage level.

An elevation level that creates excessive risk of inability to refill to a reasonable level is considered low. BC Hydro does not have a defined elevation where the refill risk would be considered too low at the end of the fiscal year as the refill risk each year will depend on a number of factors and not just the elevation or system storage.

An elevation level that creates excessive spill risk is considered high. BC Hydro does not have a defined elevation where the spill risk would be considered too high at the end of the fiscal year as the spill risk each year will depend on a number of factors and not just the elevation or system storage.

26.0 Reference: Exhibit B-1, the Application, Section 4.4.2 discussing BC Hydro's Energy Study methodology, and Section 4.4, discussing the use of System Storage to optimize the value of BC Hydro's energy.

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	Feedback	BC Hydro Response
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2.26.2 According to this BC Hydro evidence, 8,500 GWh of energy was removed from the system during F2018 (5,000 of surplus plus 3,500 of storage reduction). Where did this 8,500 GWh of energy go? Was it all exported by Powerex?

RESPONSE:

This answer also responds to CEABC IRs 2.26.3 and 2.26.4.

BC Hydro acknowledges the inaccurate use of defined terms in the BC Hydro Transmission Service Rate Design Workshop. However, CEABC's interpretation of the evidence provided in the preamble is incorrect and 8,500 GWh was not removed from the system.

The three components of Market Energy costs and revenues are defined in section 4.2.4 of Chapter 4 of the Application. The fiscal 2018 Market Energy numbers are provided in Appendix A, Schedule 4.0 (page 38 of 80) and are reproduced below. Numbers are in GWh:

Market Electricity Purchases	**150**
Surplus Sales (freshet forced and system refill) ***(freshet forced sales with system at minimum generation & other sales through July 31)***	**(2,230)**
Surplus Sales (discretionary sale) ***(discretionary sales to optimize longer term energy surplus position)***	**(2,842)**
Net Purchases (Sales) from Powerex (i.e., trade)	**(557)**
Total Purchases (Sales) from System	**(5,479)**

Surplus Sales have been further broken into two categories:

1. **Surplus Sales (freshet forced and system refill management): These sales were a combination of forced sales, driven by the hourly/daily physical load-resource balance in the system, and sales that were required to manage system refill and reduce spill.**

2. **Surplus Sales (discretionary sales across the balance of the fiscal year): These sales were made at high market prices, with the intent of managing the seasonal surplus position of the system. These sales were informed by the Energy Studies modeling.**

The decisions made regarding system storage operations in fiscal 2018 were informed by the Energy Studies optimization modelling that is discussed in section 4.4.2 in Chapter 4 of the Application.

Across late summer in 2017 (part of fiscal 2018), significant sales were made into high priced U.S. markets (Mid-C heavy load hour prices averaged US$49 for August 2017 with daily prices exceeding US$100 on a number of days) during a period when BC Hydro was forecasting a surplus in the range of 4,000 to 5,000 GWh. With dry conditions emerging in the early fall, the actual fiscal 2018 surplus[1] was approximately 2,300 GWh and the total volume withdrawn from system storage was approximately 3,500 GWh.

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[1] **As described in BC Hydro's response to BCUC IR 1.23.5, BC Hydro defines a surplus to be the amount by which system inflows plus deliveries from EPA contracts exceeds load, and a deficit to be a negative surplus. As such, any variability across a year, in the system inflow, Electricity Purchase Agreement deliveries, and system loads, will result in changes to both the forecasted and eventual outcomes for the surplus/deficit energy position.**

Clean Energy Association of B.C. Information Request No. **2.26.3** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

26.0 Reference: Exhibit B-1, the Application, Section 4.4.2 discussing BC Hydro's Energy Study methodology, and Section 4.4, discussing the use of System Storage to optimize the value of BC Hydro's energy.

In the Summary Notes to the October 11, 2018 Transmission Service Rate Design Workshop, BC Hydro reported that *"the surplus energy volume from most recent fiscal year (F2018) was just over 5,000 GWh."* (statement highlighted in the Summary Notes below)

2.	**Lok Chao Liu, Yotta Technologies Inc.** **Question** - Wanted clarification on the size of the surplus and the contribution of industrial load to total domestic load. He referred back to Keith Anderson's (page 7 slide) where the annual consumption for industrials was 16,000 GWh/yr and is now ~ 13,500 GWh/yr. **Question** - Wanted clarification on BCH's installed generation capacity and current system peaks. **Question** – Why are Manitoba Hydro rates lower than BCH's? **Question** – What is the scale/size of the surplus? Like a thousand megawatts?	The industrial customer portion of BCH's total domestic load, by energy volume, is about 25 per cent. BCH has about 11,000 MW of installed generation, the majority of which is large hydro. In terms of peak demand, BCH is a winter peaking utility although summer peaks (due to AC loads) have been increasing. Peak loads occur during heavy load hours (typically 4 p.m. to 8 p.m.) on cold winter nights. Subject to check, peak domestic loads are ~ 8,500 MW*. ***Updated Response:** • Peak Winter demand: 10,200 MW

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	Feedback	BC Hydro Response
		• Peak Summer demand: 7,500 MW Confirmed that Manitoba Hydro's rates are currently lower than BCH's. The energy surplus varies from year to year and on a planning basis vs actual basis. Forecast is based on average water. Actual depends on system conditions - which are highly variable. For context, the surplus energy volume from most recent fiscal year (F2018) was just over 5,000 GWh.

In Section 4.4.4 of the Application, BC Hydro's System Storage is defined as follows:

"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."

Table 4-1 (page 4-18) reports the year-end System Storage quantities, in GWh, as follows:

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

From this BC Hydro evidence, it appears that, even though there was an apparent 5,000 GWh surplus of energy in the fiscal year 2018, BC Hydro chose to run down its reservoir levels by 3,500 GWh compared to the levels at the start of F2018 (the highlighted values show 13,208 GWh at the end of F2017 vs. 9,736 GWh at the end of F2018, a drop of approximately 3,500 GWh).

2.26.3 Since BC Hydro made the decision to divest itself of the 5,000 GWh of surplus energy and to also run down its System Storage levels during F2018, was that decision made as a result of its monthly Energy Studies optimization modeling, as discussed in Section 4.4.2 of the Application? If not, why not? If so, then what pertinent factors from the optimization modeling convinced BC Hydro to do this?

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.26.2 where we describe the factors that influenced system operations in fiscal 2018.

26.0 Reference: Exhibit B-1, the Application, Section 4.4.2 discussing BC Hydro's Energy Study methodology, and Section 4.4, discussing the use of System Storage to optimize the value of BC Hydro's energy.

In the Summary Notes to the October 11, 2018 Transmission Service Rate Design Workshop, BC Hydro reported that *"the surplus energy volume from most recent fiscal year (F2018) was just over 5,000 GWh."* (statement highlighted in the Summary Notes below)

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From this BC Hydro evidence, it appears that, even though there was an apparent 5,000 GWh surplus of energy in the fiscal year 2018, BC Hydro chose to run down its reservoir levels by 3,500 GWh compared to the levels at the start of F2018 (the highlighted values show 13,208 GWh at the end of F2017 vs. 9,736 GWh at the end of F2018, a drop of approximately 3,500 GWh).

2.26.4 During the same F2018 period, how much energy was imported by Powerex, both for trade and for domestic purposes? Was an additional amount equivalent to all of this imported energy also exported?

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.26.2 for a breakdown of the Market Energy Purchases for domestic purposes. Please also refer to BC Hydro's response to BCUC IR 1.3.2 with respect to the Letter Agreement between BC Hydro and Powerex – Forward Electricity Purchases[1] for a breakdown of Powerex imports during fiscal 2018.

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[1] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-filings/fep/00-2019-05-23-bchydro-bcuc-wm.pdf.

26.0 Reference: Exhibit B-1, the Application, Section 4.4.2 discussing BC Hydro's Energy Study methodology, and Section 4.4, discussing the use of System Storage to optimize the value of BC Hydro's energy.

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	Feedback	BC Hydro Response
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From this BC Hydro evidence, it appears that, even though there was an apparent 5,000 GWh surplus of energy in the fiscal year 2018, BC Hydro chose to run down its reservoir levels by 3,500 GWh compared to the levels at the start of F2018 (the highlighted values show 13,208 GWh at the end of F2017 vs. 9,736 GWh at the end of F2018, a drop of approximately 3,500 GWh).

2.26.5 Please provide a table (including a working Excel model) showing the system energy flows by month over the history period from January, 2016 to March, 2019. This table should show the system generation, the domestic load, the imports for both the trade and the domestic accounts, and the exports for both the trade and the domestic accounts, and the monthly net change in System Storage.

RESPONSE:

This answer also responds to CEABC IR 2.38.5.

This response includes monthly actual generation and System Storage data which is considered commercially sensitive and which has been redacted in the public version of the response. Publication of this information would enable third-parties to model BC Hydro's system to estimate the depth of BC Hydro's energy need and to predict BC Hydro's import and export requirements. Given the high degree of sensitivity around these numbers, and the significant potential for harm that would result from inadvertent disclosure, the un-redacted version of this response is being made available to the BCUC only.

The first table below provides monthly system energy data over the period January 2016 to March 2019, broken down by system generation, domestic load, consolidated (trade and domestic) imports and exports, and the monthly net change in System Storage.

As requested in CEABC IR 2.38.5, the second table shows the monthly system generation broken down over the following components: EPA generation, BC Hydro must-run (run-of-river) generation, BC Hydro storage dam (Peace and Columbia) generation, BC Hydro Other generation (Kootenay, Pend d'Oreille, Rupert Generating Station, Burrard Generating Station), and Coordination Agreements.

The data in both tables reflects only the generation and load for the integrated system and does not include Fort Nelson generation or load.

Table 1 (all values in GWh)

Date	[redacted]	[redacted]	Trade and Domestic Imports	Trade and Domestic Exports	[redacted]
2016-01-01	[redacted]	[redacted]	129	-782	[redacted]
2016-02-01	[redacted]	[redacted]	297	-166	[redacted]
2016-03-01	[redacted]	[redacted]	288	-97	[redacted]
2016-04-01	[redacted]	[redacted]	185	-228	[redacted]
2016-05-01	[redacted]	[redacted]	15	-847	[redacted]
2016-06-01	[redacted]	[redacted]	4	-973	[redacted]
2016-07-01	[redacted]	[redacted]	30	-1036	[redacted]
2016-08-01	[redacted]	[redacted]	110	-804	[redacted]
2016-09-01	[redacted]	[redacted]	194	-303	[redacted]
2016-10-01	[redacted]	[redacted]	191	-137	[redacted]
2016-11-01	[redacted]	[redacted]	81	-589	[redacted]
2016-12-01	[redacted]	[redacted]	42	-846	[redacted]
2017-01-01	[redacted]	[redacted]	25	-798	[redacted]
2017-02-01	[redacted]	[redacted]	232	-284	[redacted]
2017-03-01	[redacted]	[redacted]	391	-153	[redacted]
2017-04-01	[redacted]	[redacted]	280	-230	[redacted]
2017-05-01	[redacted]	[redacted]	81	-506	[redacted]
2017-06-01	[redacted]	[redacted]	51	-717	[redacted]
2017-07-01	[redacted]	[redacted]	6	-1059	[redacted]
2017-08-01	[redacted]	[redacted]	54	-1190	[redacted]
2017-09-01	[redacted]	[redacted]	23	-1023	[redacted]
2017-10-01	[redacted]	[redacted]	67	-508	[redacted]
2017-11-01	[redacted]	[redacted]	74	-339	[redacted]
2017-12-01	[redacted]	[redacted]	75	-815	[redacted]

Date	[redacted]	[redacted]	Trade and Domestic Imports	Trade and Domestic Exports	[redacted]
2018-01-01	[redacted]	[redacted]	243	-331	[redacted]
2018-02-01	[redacted]	[redacted]	325	-215	[redacted]
2018-03-01	[redacted]	[redacted]	323	-198	[redacted]
2018-04-01	[redacted]	[redacted]	429	-105	[redacted]
2018-05-01	[redacted]	[redacted]	87	-429	[redacted]
2018-06-01	[redacted]	[redacted]	100	-407	[redacted]
2018-07-01	[redacted]	[redacted]	14	-892	[redacted]
2018-08-01	[redacted]	[redacted]	144	-806	[redacted]
2018-09-01	[redacted]	[redacted]	239	-237	[redacted]
2018-10-01	[redacted]	[redacted]	229	-464	[redacted]
2018-11-01	[redacted]	[redacted]	618	-94	[redacted]
2018-12-01	[redacted]	[redacted]	544	-185	[redacted]
2019-01-01	[redacted]	[redacted]	234	-319	[redacted]
2019-02-01	[redacted]	[redacted]	141	-472	[redacted]
2019-03-01	[redacted]	[redacted]	502	-40	[redacted]

Table 2 (all values in GWh)

Date	EPA Generation	BCH Must-Run Generation	BCH Storage Dam Generation	BCH Other Generation	Coordination Agreements
2016-01-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016-02-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016-03-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016-04-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016-05-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016-06-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016-07-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016-08-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016-09-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016-10-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016-11-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016-12-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017-01-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017-02-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Date	EPA Generation	BCH Must-Run Generation	BCH Storage Dam Generation	BCH Other Generation	Coordination Agreements
2017-03-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017-04-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017-05-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017-06-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017-07-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017-08-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017-09-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017-10-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017-11-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017-12-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018-01-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018-02-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018-03-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018-04-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018-05-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018-06-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018-07-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018-08-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018-09-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018-10-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018-11-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018-12-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019-01-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019-02-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019-03-01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

27.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.5.1, Surplus Sales

While the CEABC appreciates BC Hydro's response to CEABC IR 1.5.1, and the cross reference to BCUC IR 1.15.3, the CEABC seeks further clarification of the surpluses and deficits related to BC Hydro's planning and operational views.

Page 1 of Zapped: A Review of BC Hydro's Purchase of Power from Independent Power Producers Conducted for the Ministry of Energy Mines and Petroleum Resources – February 2019, states (underlining added to focus point of reference):

"Government directed BC Hydro to purchase 8,500 GWh of Firm energy BC Hydro did not need. This direction of BC Hydro's actions is manifest in the Response EPAs (Electricity Purchase Agreements) through which <u>BC Hydro managed to acquire 9,500 GWh of blended energy</u>, which is equivalent to 8,075 GWh of Firm energy."

2.27.1 Does the referenced 9,500 GWh of surplus energy correctly describe BC Hydro's apparent energy surplus for either the Planning View or the Operational View?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.15.3 where we provide the estimated system surplus volumes from both a Planning View and an Operating View.

27.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.5.1, Surplus Sales

Hansard transcript from the Afternoon Sitting of May 9, 2019 (underlining added to focus point of reference):

A. Weaver: "I shake my head every time I get an answer. The minister is saying what the report concludes, but the report assumed the conclusion that it concluded. So it's kind of circular to suggest that the report is concluding that the surplus required them to go to the IPPs. It's just circular logic. I'll ask another question, then. What is the total surplus energy that is produced in British Columbia each year, on average? Simple question."

Hon. M. Mungall: "From year to year, the total that the member is asking about does vary. But we can give him that, on average, it's 4,000 gigawatt hours per year."

2.27.2 Does the referenced 4,000 GWh of total surplus energy produce in B.C. each year, on average, correctly describe BC Hydro's apparent energy surplus for either the Planning View or the Operational View?

RESPONSE:

As shown in BC Hydro's response to BCUC IR 1.15.3, BC Hydro's average forecast system surplus volume is about 4,000 GWh per year (over the fiscal 2020 to fiscal 2024 period) from an Operating View.

28.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.5.1, Surplus Sales

While the CEABC appreciates BC Hydro's response to CEABC IR 1.5.1, and the cross reference to BCUC IR 1.15.3, the CEABC seeks further clarification of the surpluses and deficits related to BC Hydro's planning and operational views.

In its response to BCUC IR 1.15.3, BC Hydro describes the distinction between the planning and the operational views as follows:

"In summary, the planning view reflects the capability of resources based on BC Hydro's planning criteria while the operational view shows the forecasted operation of these same resources given market and system conditions."

BC Hydro then presents the following two tables illustrating the different Surplus/Deficit projections resulting from these two views over the period F2020 to F2024:

Table 1 Operational View of Energy Surplus/Deficit based on October 2018 Energy Study

GWh	F2020	F2021	F2022	F2023	F2024
Surplus/Deficit	2,985	3,834	4,318	4,119	3,029

Table 2 Planning Vie of Energy Surplus/Deficit based on October 2018 Short Term Load Forecast

	GWh	F2020	F2021	F2022	F2023	F2024
Line 14	**Surplus / (Deficit)**	5,677	6,293	6,517	6,191	5,348

According to these tables, the operational view projects a surplus which is 2,000 to 3,000 GWh less than that projected by the planning view.

2.28.1 Please describe all the differences between the assumptions used under "BC Hydro's planning criteria" and those that reflect "market and system conditions". In particular, how do these two separate sets of assumptions differ with regard to the following:

- The assumed output of the Heritage hydro assets (e.g. under average water conditions vs. the critical water period);
- The assumed purchases from Alcan (i.e. deliveries from Kemano under average vs critical water conditions);
- The assumed purchases from Island Generation;
- The assumed purchases from IPPs and from EPA Renewals (e.g. under average vs. critical water conditions);

- The assumed savings from DSM programs
- The assumed savings from price elasticity or natural conservation
- Any other significantly different assumptions between planning and operational criteria?

RESPONSE:

The Planning View reflects the capability of resources based on BC Hydro's planning criteria. The Operational View shows the forecast operation of these same resources given market and system conditions. The table below provides a description of the assumptions used under BC Hydro's Planning View and BC Hydro's Operational View.

The largest difference between the Planning View and the Operational View is the generation from Island Generation. The Planning View includes the amount of generation that Island Generation is capable of producing in a year (2,170 GWh), whereas the Operational View uses the generation forecast for Island Generation from the Energy Studies which reflects generation for both reliability and economics. In Table 1 of BC Hydro's response to BCUC IR 1.15.3, the forecast generation of Island Generation for the period fiscal 2020 to fiscal 2024 ranges from 0 to 26 GWh per year.

	Planning View	Operational View
Heritage Hydro	Based on system modelling that maximizes energy.	Based on system modelling that maximizes revenue while meeting load requirements.
Rio Tinto Alcan	Assumes amount of energy that Rio Tinto Alcan can generate during BC Hydro's critical water period.	Assumes the forecast that is provided by Rio Tinto Alcan based on current conditions.
Island Generation	Assumes generating capability based on a 90 per cent availability factor (2,170 GWh).	Reflects expected usage based on the Energy Studies modelled dispatch.

	Planning View	Operational View
IPPs and EPA Renewals	**Run-of-river and storage hydro – assumes amount of energy that can be generated during BC Hydro's critical water period.** **For all other resources, assumes estimates provided by IPPs.** **EPA renewal percentage assumptions are the same as the Operating View.**	**For several of the run-of-river and storage hydro – forecast energy that can be generated based on current conditions. A few years in the future this converges on expected generation under average water.** **For all other IPP resources, assumes average energy based on historic actual deliveries or estimates provided by the IPPs adjusted as described in BC Hydro's response to BCUC IR 1.15.2.** **For information on our IPP forecast in the Operating View, including the EPA renewal assumptions, please refer to BC Hydro's response to BCUC IR 1.15.2.**
DSM Programs	**No difference between operational and planning views**	
Price Elasticity	**No difference between operational and planning views**	

28.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.5.1, Surplus Sales

While the CEABC appreciates BC Hydro's response to CEABC IR 1.5.1, and the cross reference to BCUC IR 1.15.3, the CEABC seeks further clarification of the surpluses and deficits related to BC Hydro's planning and operational views.

In its response to BCUC IR 1.15.3, BC Hydro describes the distinction between the planning and the operational views as follows:

"In summary, the planning view reflects the capability of resources based on BC Hydro's planning criteria while the operational view shows the forecasted operation of these same resources given market and system conditions."

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Line 14	Surplus / (Deficit)	5,677	6,293	6,517	6,191	5,348

According to these tables, the operational view projects a surplus which is 2,000 to 3,000 GWh less than that projected by the planning view.

2.28.2 What aspects of the current "market and system conditions" are expected to be so significantly different from "BC Hydro's planning criteria" and so long lasting that their impact will remain significant for at least the next 5 years? How long into the future are these impacts expected to persist?

RESPONSE:

The premise of the question is incorrect. There is not a significant persistent issue that is causing a difference between our Planning and Operating Views. Please refer to BC Hydro's response to CEABC IR 2.28.1 for a further description of the Planning View and Operational View, and a detailed comparison of resource assumptions.

28.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.5.1, Surplus Sales

While the CEABC appreciates BC Hydro's response to CEABC IR 1.5.1, and the cross reference to BCUC IR 1.15.3, the CEABC seeks further clarification of the surpluses and deficits related to BC Hydro's planning and operational views.

In its response to BCUC IR 1.15.3, BC Hydro describes the distinction between the planning and the operational views as follows:

"In summary, the planning view reflects the capability of resources based on BC Hydro's planning criteria while the operational view shows the forecasted operation of these same resources given market and system conditions."

BC Hydro then presents the following two tables illustrating the different Surplus/Deficit projections resulting from these two views over the period F2020 to F2024:

Table 1 Operational View of Energy Surplus/Deficit based on October 2018 Energy Study

GWh	F2020	F2021	F2022	F2023	F2024
Surplus/Deficit	2,985	3,834	4,318	4,119	3,029

Table 2 Planning Vie of Energy Surplus/Deficit based on October 2018 Short Term Load Forecast

	GWh	F2020	F2021	F2022	F2023	F2024
Line 14	**Surplus / (Deficit)**	5,677	6,293	6,517	6,191	5,348

According to these tables, the operational view projects a surplus which is 2,000 to 3,000 GWh less than that projected by the planning view.

2.28.3 For clarity, please provide the values in Table 2 (the Planning View) on the basis of the critical water period.

RESPONSE:

In accordance with the 2012 amendment to Special Direction 10, BC Hydro assumes average water conditions for BC Hydro's Heritage Assets for planning purposes.

BC Hydro is not able to provide values for the time period in Table 2 on the basis of a critical water period, as BC Hydro does not have an updated critical period study available for the resource mix in place for the Test Period.

Please refer to BC Hydro's response to CEABC IR 2.36.1 for information that is available from the long term study on Heritage Resources capability conducted in 2018.

28.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.5.1, Surplus Sales

While the CEABC appreciates BC Hydro's response to CEABC IR 1.5.1, and the cross reference to BCUC IR 1.15.3, the CEABC seeks further clarification of the surpluses and deficits related to BC Hydro's planning and operational views.

In its response to BCUC IR 1.15.3, BC Hydro describes the distinction between the planning and the operational views as follows:

"In summary, the planning view reflects the capability of resources based on BC Hydro's planning criteria while the operational view shows the forecasted operation of these same resources given market and system conditions."

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Line 14	Surplus / (Deficit)	5,677	6,293	6,517	6,191	5,348

According to these tables, the operational view projects a surplus which is 2,000 to 3,000 GWh less than that projected by the planning view.

2.28.4 In each of the Tables 1 and 2, what amounts of energy are assumed for IPPs and EPA Renewals under both average and critical water conditions?

RESPONSE:

The table below shows the amount of energy assumed for IPPs, EPA Renewals and future projects under the Standing Offer Program (SOP) for the Operational View and the Planning View. As the amendment to Special Direction 10 applies only to BC Hydro Heritage Resources, the planning assumptions for IPPs and EPA

renewals remain unchanged. Please refer to BC Hydro's response to CEABC IR 2.28.1, which provides the assumptions under Operational and Planning Views and notes that the largest difference between the Planning View and Operational View is the generation from Island Generation.

Please note that the future Standing Offer Program (SOP) projects are shown separately as they are neither existing or committed IPPs nor EPA renewals.

(GWh)	F2020	F2021	F2022	F2023	F2024
	Operational View (Table 1)				
IPPs	14,917	14,911	14,888	14,768	14,538
EPA Renewals	446	965	1,213	1,308	1,501
Future SOPs	70	149	230	230	230
	Planning View (Table 2)				
IPPs	16,898	16,607	16,293	14,173	13,762
EPA Renewals	593	1,105	1,352	3,430	3,789
Future SOPs	67	145	226	226	226

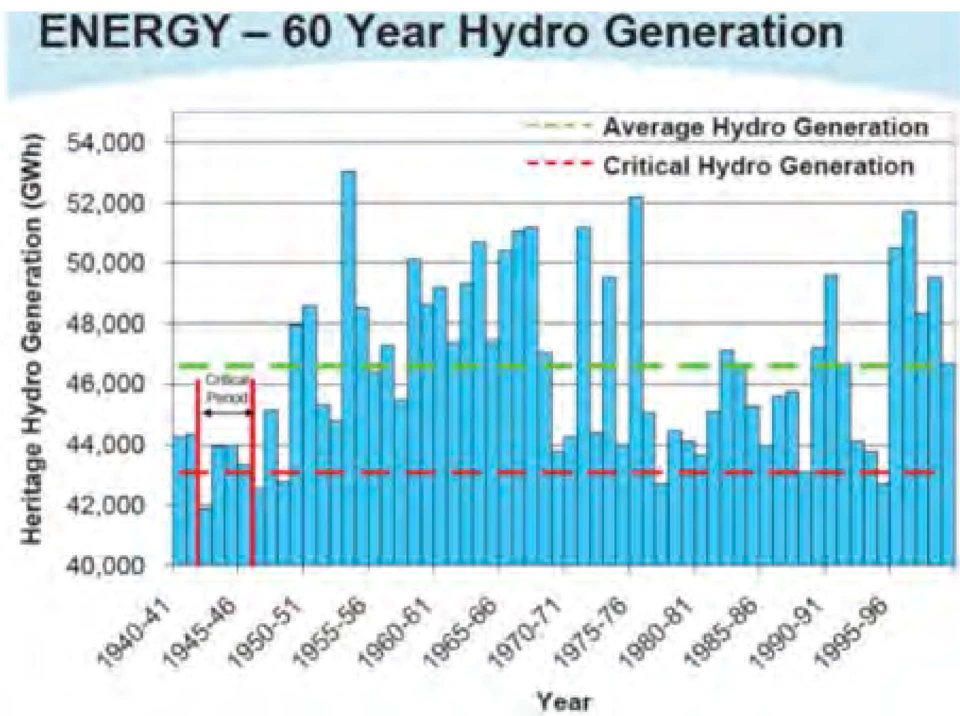
29.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.6.2, the variability of Surplus Sales

BC Hydro's response to CEABC IR 1.6.2, included reference to the "critical water period in the 1940's" as follows (underlining added to focus the point of reference):

"Energy Study models use an ensemble of historic calendar years beginning in1973 to develop a baseline definition for 'normal'. More details on the structure of this ensemble are provided in BC Hydro's response to BCUC IR 1.31.1. <u>The critical water period in the 1940s is therefore not included in the Energy Studies.</u> The 1973 start date was chosen for the Energy Studies because as of that year both the GM Shrum and Mica generating stations were in-service, and as a result consistently calculated historic inflow data is available starting in 1973.

BC Hydro defines the critical period as the most adverse sequence of stream flows in the historical period of record during which the system generates the least amount of energy while drafting the active storage of the system reservoirs from full to empty."

BC Hydro included the following "60 Year Hydro Generation" graph from a June 8, 2007 presentation by BC Hydro, entitled "System Needs: An Energy Planning Perspective"**.** It shows that the years in the early 1940's were the lowest hydro generation. The last year on the graph appears to be 1996.



2.29.1 Please update to this Hydro Generation history graph to cover 1940 - 2019.

RESPONSE:

This answer also responds to CEABC IRs 2.29.2 and 2.29.3.

The data in the chart in the preamble to the question is from a long-term planning study for the 2003 Heritage Contract Inquiry that was used to determine Heritage Resources capability for the Heritage Contract. It is important to note that the graph that is reproduced in the preamble to the question does not show actual BC Hydro historic heritage hydro generation. Rather, the graph shows hypothetical generation that could have resulted from BC Hydro's heritage assets as they existed at the time the graph was created with historic hydrological data (for example, many of BC Hydro's major generating stations were not yet constructed as of the 1940s).

BC Hydro does not have an updated long-term planning study available with the same assumptions that were used to create the graph in the preamble to the question. That type of long-term planning study has not been updated, and takes approximately two to three months to complete. Accordingly, BC Hydro is not able to complete the task in the time allotted for responses to this round of information requests.

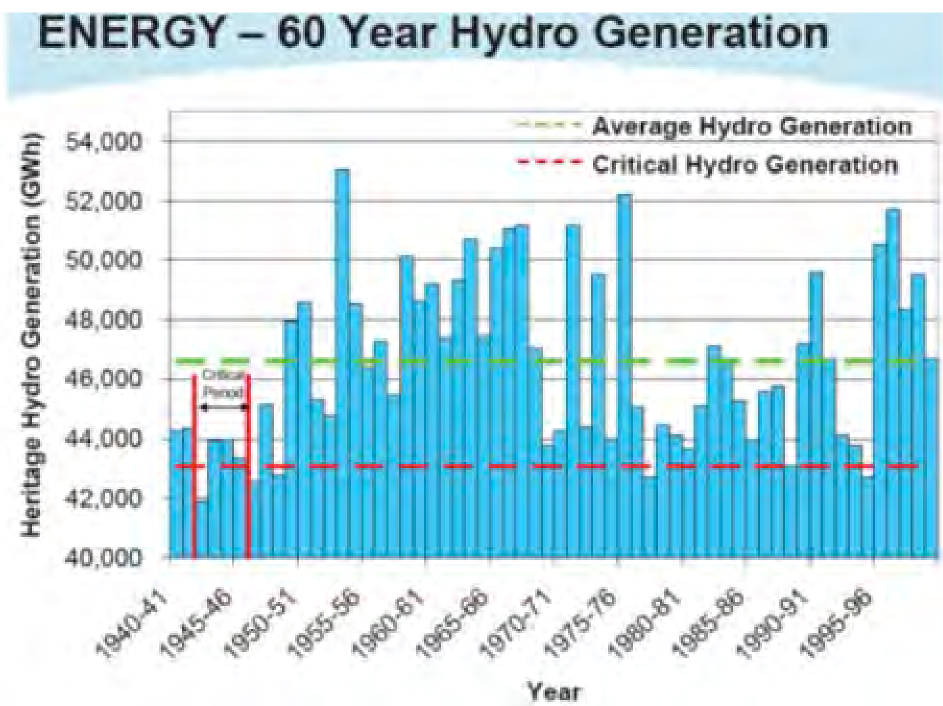
29.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.6.2, the variability of Surplus Sales

BC Hydro's response to CEABC IR 1.6.2, included reference to the "critical water period in the 1940's" as follows (underlining added to focus the point of reference):

"Energy Study models use an ensemble of historic calendar years beginning in1973 to develop a baseline definition for 'normal'. More details on the structure of this ensemble are provided in BC Hydro's response to BCUC IR 1.31.1. <u>The critical water period in the 1940s is therefore not included in the Energy Studies.</u> The 1973 start date was chosen for the Energy Studies because as of that year both the GM Shrum and Mica generating stations were in-service, and as a result consistently calculated historic inflow data is available starting in 1973.

BC Hydro defines the critical period as the most adverse sequence of stream flows in the historical period of record during which the system generates the least amount of energy while drafting the active storage of the system reservoirs from full to empty."

BC Hydro included the following "60 Year Hydro Generation" graph from a June 8, 2007 presentation by BC Hydro, entitled "System Needs: An Energy Planning Perspective"**.** It shows that the years in the early 1940's were the lowest hydro generation. The last year on the graph appears to be 1996.



2.29.2 Please update the average and critical generation numbers (the horizontal green and red lines).

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.29.1.

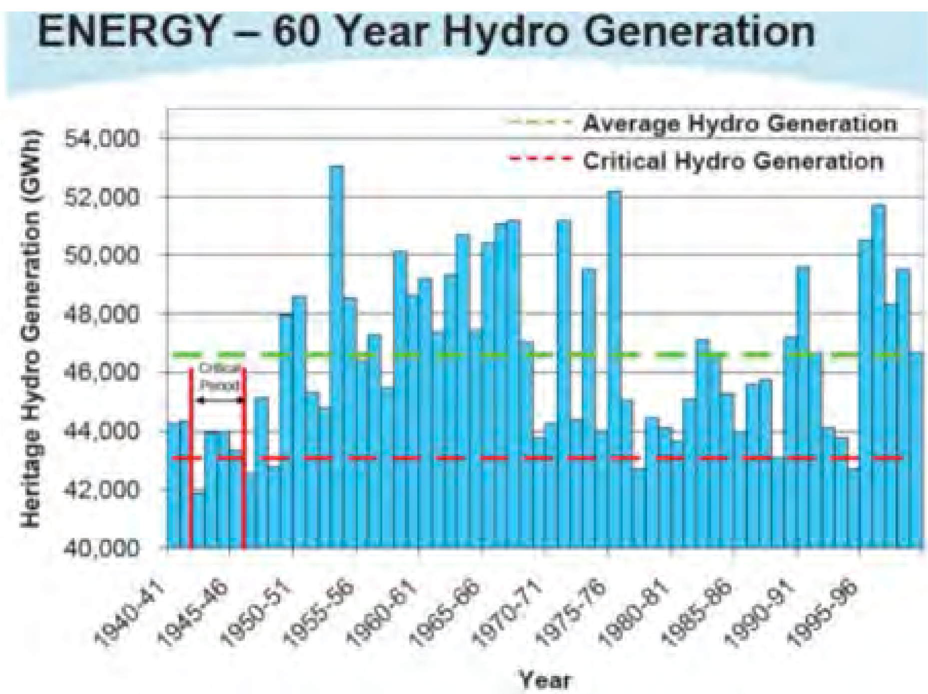
29.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.6.2, the variability of Surplus Sales

BC Hydro's response to CEABC IR 1.6.2, included reference to the "critical water period in the 1940's" as follows (underlining added to focus the point of reference):

"Energy Study models use an ensemble of historic calendar years beginning in1973 to develop a baseline definition for 'normal'. More details on the structure of this ensemble are provided in BC Hydro's response to BCUC IR 1.31.1. <u>The critical water period in the 1940s is therefore not included in the Energy Studies.</u> The 1973 start date was chosen for the Energy Studies because as of that year both the GM Shrum and Mica generating stations were in-service, and as a result consistently calculated historic inflow data is available starting in 1973.

BC Hydro defines the critical period as the most adverse sequence of stream flows in the historical period of record during which the system generates the least amount of energy while drafting the active storage of the system reservoirs from full to empty."

BC Hydro included the following "60 Year Hydro Generation" graph from a June 8, 2007 presentation by BC Hydro, entitled "System Needs: An Energy Planning Perspective". It shows that the years in the early 1940's were the lowest hydro generation. The last year on the graph appears to be 1996.



2.29.3 Please include a working excel spreadsheet containing the annual hydro generation numbers (GWh) that appear on the graph and the average and critical hydro generation levels when they changed over time.

RESPONSE:

The working excel spreadsheet is not available. Please refer to BC Hydro's response to CEABC IR 2.29.1.

30.0 Reference: Miscellaneous – The impact of Amended Special Direction 10

Amended Special Direction 10 changed BC Hydro's planning criteria for its Heritage Assets from "critical water" to "average water".

2.30.1 What impact did that change to "average water" have on the generation that would be assumed from the Heritage Assets under "BC Hydro's planning criteria"?

RESPONSE:

In 2012, the amendment to Special Direction 10 changed BC Hydro's planning criteria from critical water to average water, thus increasing the generation for planning purposes for BC Hydro's Heritage Resources. The change to "average water" effectively increased the generation that would be assumed from the Heritage Assets by 4,100 GWh/year.

As described in BC Hydro's response to CEABC IR 1.6.6, the change in 2012 also reflected additional system capability from system changes which occurred between the introduction of Special Direction 10 and the amendment to Special Direction 10, for a total increase of 5,600 GWh/year.

30.0 Reference: Miscellaneous – The impact of Amended Special Direction 10

Amended Special Direction 10 changed BC Hydro's planning criteria for its Heritage Assets from "critical water" to "average water".

2.30.2 Under the current planning criteria (subsequent to Amended Special Direction 10), what is the assumed annual generation from the Heritage Assets?

RESPONSE:

Under current planning criteria, the annual generation from the Heritage Resources during the Test Period is assumed to be 46,916 GWh/year.

30.0 Reference: Miscellaneous – The impact of Amended Special Direction 10

Amended Special Direction 10 changed BC Hydro's planning criteria for its Heritage Assets from "critical water" to "average water".

2.30.3 Under the current operational criteria, reflecting market and system conditions, what is the assumed annual generation from the Heritage Assets?

RESPONSE:

This response includes confidential information that pertains to our August 2019 Cost of Energy Evidentiary Update, in accordance with Order No. G-146-19, which has been redacted in the public version of this response. The un-redacted version of the response is being made available to the BCUC only.

Special Direction 10 is focussed on planning, and has no impact to BC Hydro's Operational View of energy available from the Heritage Assets. In addition, there is no specific criteria for defining the annual energy in the Operational View. Instead, the Energy Studies forecast what energy is available energy to meet load and forecast the optimal dispatch of the system including imports/exports to meet load.

The Heritage Hydro GWh forecast for fiscal 2020 to fiscal 2024 is provided in the table below:

GWh	F2020 EU	F2021 EU	F2022 Forecast	F2023 Forecast	F2024 Forecast
Heritage Energy	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

30.0 Reference: Miscellaneous – The impact of Amended Special Direction 10

Amended Special Direction 10 changed BC Hydro’s planning criteria for its Heritage Assets from “critical water” to “average water”.

2.30.4 What impact did the change to “average water” have on the generation that would be assumed from Independent Power Projects under planning criteria? Or under operational criteria?

RESPONSE:

The amendment to Special Direction 10 changed BC Hydro’s planning criteria from “critical water” to “average water” for its Heritage Assets only. There is no impact on the generation that would be assumed from Independent Power Projects.

Please refer to BC Hydro’s response to CEABC IR 2.28.1 for IPP assumptions under Planning and Operational Views.

30.0 Reference: Miscellaneous – The impact of Amended Special Direction 10

Amended Special Direction 10 changed BC Hydro’s planning criteria for its Heritage Assets from “critical water” to “average water”.

2.30.5 What total impact did the change to “average water” have on any forecasted energy surpluses or deficits?

RESPONSE:

Please refer to BC Hydro’s response to CEABC IR 2.30.1 for a description of the impact of the change to average water on BC Hydro’s Heritage Resources, which increased the surplus (or reduced a deficit) by 4,100 GWh/year.

As described in BC Hydro’s response to CEABC IR 2.30.4, the amendment to Special Direction 10 had no impact on the generation assumed from Independent Power Projects.

31.0 Reference: Exhibit B-6, BC Hydro Response to CEABC IR 1.5.3, Second Kemano Diversion Tunnel

In its response, BC Hydro states: "These amounts reflect forecast hydrology and expected increases to the generation, as permitted under the 2007 EPA, due to the completion of a second tunnel (the Kemano T2 Project) expected by the end of 2020."

2.31.1 How will the second tunnel increase generation capability?

RESPONSE:

Rio Tinto Alcan has advised BC Hydro that the second tunnel is being constructed primarily for de-risking and safety reasons, as the original tunnel could be subject to collapse, as with other tunnels of a similar age and profile. The addition of a second tunnel reduces friction, and in turn energy losses, and as a result is expected to increase capacity by about 100 MW to 140 MW and energy by about 50 average MW (approximately 450 GWh/yr energy), subject to hydrology, maintenance, and reservoir and operating conditions.

31.0 Reference: Exhibit B-6, BC Hydro Response to CEABC IR 1.5.3, Second Kemano Diversion Tunnel

In its response, BC Hydro states: "These amounts reflect forecast hydrology and expected increases to the generation, as permitted under the 2007 EPA, due to the completion of a second tunnel (the Kemano T2 Project) expected by the end of 2020."

2.31.2 How much will the existing capacity and energy capabilities of Kemano in megawatts and megawatt hours be increased?

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.31.1.

31.0 Reference: Exhibit B-6, BC Hydro Response to CEABC IR 1.5.3, Second Kemano Diversion Tunnel

In its response, BC Hydro states: "These amounts reflect forecast hydrology and expected increases to the generation, as permitted under the 2007 EPA, due to the completion of a second tunnel (the Kemano T2 Project) expected by the end of 2020."

2.31.3 Will the grade line profile of the second tunnel be any different than the existing tunnel?

RESPONSE:

Rio Tinto Alcan has advised BC Hydro that the second tunnel will be mainly constructed in parallel to the existing tunnel.

31.0 Reference: Exhibit B-6, BC Hydro Response to CEABC IR 1.5.3, Second Kemano Diversion Tunnel

In its response, BC Hydro states: "These amounts reflect forecast hydrology and expected increases to the generation, as permitted under the 2007 EPA, due to the completion of a second tunnel (the Kemano T2 Project) expected by the end of 2020."

2.31.4 Will the existing tunnel remain in daily operation or be used for backup or some other role?

RESPONSE:

Rio Tinto Alcan has advised BC Hydro that the existing tunnel will remain in daily operation.

31.0 Reference: Exhibit B-6, BC Hydro Response to CEABC IR 1.5.3, Second Kemano Diversion Tunnel

In its response, BC Hydro states: "These amounts reflect forecast hydrology and expected increases to the generation, as permitted under the 2007 EPA, due to the completion of a second tunnel (the Kemano T2 Project) expected by the end of 2020."

2.31.5 Will the second tunnel supply the existing penstocks?

RESPONSE:

Rio Tinto Alcan has advised BC Hydro that the second tunnel will supply the existing penstocks.

31.0 Reference: Exhibit B-6, BC Hydro Response to CEABC IR 1.5.3, Second Kemano Diversion Tunnel

In its response, BC Hydro states: "These amounts reflect forecast hydrology and expected increases to the generation, as permitted under the 2007 EPA, due to the completion of a second tunnel (the Kemano T2 Project) expected by the end of 2020."

2.31.6 Are the existing penstocks being replaced or modified to provide additional water flow to the existing turbines and generators at the Kemano powerhouse?

RESPONSE:

Rio Tinto Alcan has advised BC Hydro that the existing penstocks are not being replaced or modified to provide additional water flow to the existing turbines and generators.

31.0 Reference: Exhibit B-6, BC Hydro Response to CEABC IR 1.5.3, Second Kemano Diversion Tunnel

In its response, BC Hydro states: "These amounts reflect forecast hydrology and expected increases to the generation, as permitted under the 2007 EPA, due to the completion of a second tunnel (the Kemano T2 Project) expected by the end of 2020."

2.31.7 Will the head of the Kemano project be increased with the addition of the second tunnel?

RESPONSE:

Rio Tinto Alcan has advised BC Hydro that the head of the Kemano project will not be increased with the addition of the second tunnel – both tunnels will be fed by the same reservoir.

31.0 Reference: Exhibit B-6, BC Hydro Response to CEABC IR 1.5.3, Second Kemano Diversion Tunnel

In its response, BC Hydro states: "These amounts reflect forecast hydrology and expected increases to the generation, as permitted under the 2007 EPA, due to the completion of a second tunnel (the Kemano T2 Project) expected by the end of 2020."

2.31.8 Are the existing turbines and generators at the Kemano powerhouse being replaced or modified as a result of the second tunnel?

RESPONSE:

Rio Tinto Alcan has advised BC Hydro that no direct modifications are being made to the turbines and generators as a result of the second tunnel – the turbines and generators will be operated and maintained in accordance with the flows enabled by the two tunnels.

31.0 Reference: Exhibit B-6, BC Hydro Response to CEABC IR 1.5.3, Second Kemano Diversion Tunnel

In its response, BC Hydro states: "These amounts reflect forecast hydrology and expected increases to the generation, as permitted under the 2007 EPA, due to the completion of a second tunnel (the Kemano T2 Project) expected by the end of 2020."

2.31.9 Are additional turbines being installed at the Kemano powerhouse?

RESPONSE:

Rio Tinto Alcan has advised BC Hydro that no additional turbines are being installed at the Kemano powerhouse.

31.0 Reference: Exhibit B-6, BC Hydro Response to CEABC IR 1.5.3, Second Kemano Diversion Tunnel

In its response, BC Hydro states: "These amounts reflect forecast hydrology and expected increases to the generation, as permitted under the 2007 EPA, due to the completion of a second tunnel (the Kemano T2 Project) expected by the end of 2020."

2.31.10 Was BC Hydro's approval required under the EPA for the second tunnel? If yes please provide the details.

RESPONSE:

BC Hydro's approval to proceed with the second tunnel was not required under the EPA.

32.0 Reference: Exhibit B-6, BC Hydro Response to CEABC IR 1.5.4, Kemano Deliveries

In IR 1.5.4, the CEABC requested a table showing the actual deliveries to and from Kemano for the last 5 years and projected deliveries during the test period. Although BC Hydro provided the requested information it did so only on a confidential basis. The CEABC appreciates there may be a need in certain circumstance for confidentiality in relation to projected deliveries. However, in the IPP supply list[1], the annual representative energy output for all IPP EPAs is shown including Kemano at 3,307 "Energy (GWh/yr)". The 3,307 figure is no longer relevant given, among other things:

- the Modernization Project which is referenced in the Alcan EPA[2] and is now completed;
- the Tier 1 Quantity Table in the definition of "Tier 1 Electricity Quantity" in the Alcan EPA, which shows "Tier 1 Electricity Quantity" 2017 *et seq.* as *"33 Incremental Quantity (AvMW)"*
- the definition of *"Tier 2 Electricity"* as the amount in excess of the sum of the Electricity required to service the applicable Smelter Load and Scheduled Tier 1 Electricity; and
- BC Hydro's calculation of Tier 1 average annual energy of 289 GWh and 552 GWh for Tier 2 energy as per BC Hydro's response to CEABC IR 1.5.3

2.32.1 Why is it necessary to claim confidentiality with respect to historical deliveries especially in relation to an EPA the terms and conditions of which, including price are publicly available?

RESPONSE:

Actual generation from a specific IPP project is considered commercially sensitive information of the IPP and falls under the confidential information provisions under the EPA. As a result, BC Hydro does not disclose this information unless we have the consent of the IPP to do so. BC Hydro has not received any such consent with respect to Kemano.

It is also BC Hydro's understanding that generation data for IPPs which are associated with other production facilities is considered especially sensitive to the IPP as such generation information could be potentially used to back-calculate facility production information.

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1. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/ipp-supply-list-in-operation.pdf

2 BC Hydro and Alcan Inc. 2007 Energy Purchase Agreement dated August 13, 2007

32.0 Reference: Exhibit B-6, BC Hydro Response to CEABC IR 1.5.4, Kemano Deliveries

In IR 1.5.4, the CEABC requested a table showing the actual deliveries to and from Kemano for the last 5 years and projected deliveries during the test period. Although BC Hydro provided the requested information it did so only on a confidential basis. The CEABC appreciates there may be a need in certain circumstance for confidentiality in relation to projected deliveries. However, in the IPP supply list[1], the annual representative energy output for all IPP EPAs is shown including Kemano at 3,307 “Energy (GWh/yr)”. The 3,307 figure is no longer relevant given, among other things:

- the Modernization Project which is referenced in the Alcan EPA[2] and is now completed;
- the Tier 1 Quantity Table in the definition of “Tier 1 Electricity Quantity” in the Alcan EPA, which shows “Tier 1 Electricity Quantity” 2017 *et seq.* as *“33 Incremental Quantity (AvMW)”*
- the definition of *“Tier 2 Electricity”* as the amount in excess of the sum of the Electricity required to service the applicable Smelter Load and Scheduled Tier 1 Electricity; and
- BC Hydro’s calculation of Tier 1 average annual energy of 289 GWh and 552 GWh for Tier 2 energy as per BC Hydro’s response to CEABC IR 1.5.3

2.32.2 Did the Modernization Project increase the Smelter Load as those terms are defined in the Alcan EPA above the maximum quantities set out in the table in section 6.1 of this EPA? If yes please explain including whether BC Hydro’s consent was required for such increase.

RESPONSE:

Rio Tinto Alcan has advised BC Hydro that the Modernization Project did not increase the smelter load as defined in the Rio Tinto Alcan EPA.

1. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/ipp-supply-list-in-operation.pdf

2 BC Hydro and Alcan Inc. 2007 Energy Purchase Agreement dated August 13, 2007

32.0 Reference: Exhibit B-6, BC Hydro Response to CEABC IR 1.5.4, Kemano Deliveries

In IR 1.5.4, the CEABC requested a table showing the actual deliveries to and from Kemano for the last 5 years and projected deliveries during the test period. Although BC Hydro provided the requested information it did so only on a confidential basis. The CEABC appreciates there may be a need in certain circumstance for confidentiality in relation to projected deliveries. However, in the IPP supply list[1], the annual representative energy output for all IPP EPAs is shown including Kemano at 3,307 "Energy (GWh/yr)". The 3,307 figure is no longer relevant given, among other things:

- the Modernization Project which is referenced in the Alcan EPA[2] and is now completed;
- the Tier 1 Quantity Table in the definition of "Tier 1 Electricity Quantity" in the Alcan EPA, which shows "Tier 1 Electricity Quantity" 2017 *et seq.* as *"33 Incremental Quantity (AvMW)"*
- the definition of *"Tier 2 Electricity"* as the amount in excess of the sum of the Electricity required to service the applicable Smelter Load and Scheduled Tier 1 Electricity; and
- BC Hydro's calculation of Tier 1 average annual energy of 289 GWh and 552 GWh for Tier 2 energy as per BC Hydro's response to CEABC IR 1.5.3

2.32.3 Are the projected deliveries during the test period, which BC Hydro provided to the BCUC in response to CEABC IR 1.5.4, for the operational view? If not, please provide the values for the operational view.

RESPONSE:

This answer also responds to CEABC IR 2.32.4.

This response includes commercially sensitive information which has been redacted in the public version of the response. The un-redacted version of this response is being made available to the BCUC only as public disclosure could impact BC Hydro's and the IPP's commercial interests.

Yes, the projected deliveries for the Test Period (set out in BC Hydro's response to CEABC IR 1.5.3) are relevant for the Operational View of the Local Resource Balance (LRB). The table below sets out the Tier 1 and Tier 2 volumes, that align

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1. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/ipp-supply-list-in-operation.pdf

2. BC Hydro and Alcan Inc. 2007 Energy Purchase Agreement dated August 13, 2007

with the forecast assumptions in the Application (as of October 1, 2018) and in the Evidentiary Update (as of June 1, 2018), for the test period and beyond for the operational and planning views of the LRBs. BC Hydro notes that the Planning View values do not change with the Evidentiary Update.

	F2020	F2021	F2022	F2023	F2024 and beyond
Operational View - Application					
Tier 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tier 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operational View – Evidentiary Update					
Tier 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tier 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Planning View					
Tier 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tier 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

32.0 Reference: Exhibit B-6, BC Hydro Response to CEABC IR 1.5.4, Kemano Deliveries

In IR 1.5.4, the CEABC requested a table showing the actual deliveries to and from Kemano for the last 5 years and projected deliveries during the test period. Although BC Hydro provided the requested information it did so only on a confidential basis. The CEABC appreciates there may be a need in certain circumstance for confidentiality in relation to projected deliveries. However, in the IPP supply list[1], the annual representative energy output for all IPP EPAs is shown including Kemano at 3,307 "Energy (GWh/yr)". The 3,307 figure is no longer relevant given, among other things:

- the Modernization Project which is referenced in the Alcan EPA[2] and is now completed;
- the Tier 1 Quantity Table in the definition of "Tier 1 Electricity Quantity" in the Alcan EPA, which shows "Tier 1 Electricity Quantity" 2017 *et seq.* as *"33 Incremental Quantity (AvMW)"*
- the definition of *"Tier 2 Electricity"* as the amount in excess of the sum of the Electricity required to service the applicable Smelter Load and Scheduled Tier 1 Electricity; and
- BC Hydro's calculation of Tier 1 average annual energy of 289 GWh and 552 GWh for Tier 2 energy as per BC Hydro's response to CEABC IR 1.5.3

2.32.4 For the planning view what are the expected Tier 1 and Tier 2 energy deliveries under average water conditions and during the critical water period?

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.32.3.

1. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/ipp-supply-list-in-operation.pdf

2 BC Hydro and Alcan Inc. 2007 Energy Purchase Agreement dated August 13, 2007.

33.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.5.5, Island Generation

2.33.1 BC Hydro has supplied forecast energy volumes for Island Generation for the test period on a confidential basis. If these volumes are for the operational view, please provide the energy volumes for the planning view.

RESPONSE:

The forecast energy volumes that were provided for Island Generation on a confidential basis for the test period are for the Operational View. In the Planning View, which is used for the long term Load Resource Balance, Island Generation is assumed to provide 2,170 GWh/year of energy.

33.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.5.5, Island Generation

2.33.2 The CEABC also requests that BC Hydro provide the gas transportation contracts for the transmission of natural gas from the gas fields to Island Generation and the corresponding natural gas commodity supply agreements.

RESPONSE:

BC Hydro holds a Transportation Services Agreement with FortisBC Energy (Vancouver Island) for the delivery of gas from the Sumas/Huntingdon trading hub to Island Generation. This agreement was filed with the BCUC in 2007 as part of Exhibit B-1[1] to the "Application by TGVI for the filing of BCH's Long Term Service Agreements" and was approved by BCUC Order No. G-123-07.

Natural gas to operate the Island Generation facility is purchased by BC Hydro from Powerex pursuant to the Transfer Pricing Agreement.

1 https://www.bcuc.com/Documents/Proceedings/2007/DOC_16847_B-1_TGVI_ICP-BCH_Agreements_Application.pdf.

33.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.5.5, Island Generation

2.33.3 In response to AMPC IR 1.8.1.4, BC Hydro states that Powerex purchases the natural gas for Island Generation and BC Hydro arranges gas transportation. Why does Powerex purchase gas on behalf of BC Hydro for Island Generation which is a domestic facility?

RESPONSE:

BC Hydro purchases natural gas from Powerex pursuant to the Transfer Pricing Agreement. Under the Transfer Pricing Agreement, Powerex is the market facing entity that participates in wholesale electricity and natural gas markets, including procuring wholesale natural gas for sale to BC Hydro for domestic thermal operations (including Island Generation). Powerex already has in place the necessary capabilities to procure and transport wholesale natural gas supply, manage the nominations and perform the other necessary administrative functions. This allows BC Hydro to avoid duplication of costs.

A copy of the Transfer Pricing Agreement is provided as Attachment 1 to BC Hydro's response to AMPC IR 2.46.3.

Clean Energy Association of B.C. Information Request No. **2.33.4** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit:** **B-13**

33.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.5.5, Island Generation

2.33.4 How do BC Hydro and Powerex co-ordinate the transportation and purchase of natural gas for Island Generation?

RESPONSE:

When BC Hydro determines it needs to operate Island Generation, it purchases gas from Powerex based on the provisions in the Transfer Price Agreement (Section 10 and Appendix B) and Powerex arranges delivery to Sumas/Huntington.

Please refer to BC Hydro's response to CEABC IR 2.33.2 for a description of transport from Sumas/Huntington to Island Generation.

33.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.5.5, Island Generation

2.33.5 In response to BCUC IR 1.22.1 BC Hydro referred to: "… the gas transportation contract assigned to Powerex in November 2018". Please provide the gas transportation contract and assignment.

RESPONSE:

The natural gas transportation contract that was assigned by to Powerex in November 2018 is available on the Westcoast pipeline website on the "Informational Postings"; page, under "Capacity" and "Pipeline Contracted Firm Service." The link provided below lists the August 2019 firm service contract on the T-South system (Zone 4). Powerex's November 2018 contract is listed on page 8.

https://noms.wei-pipeline.com/CustomerContent/s_and_t_firm/tsouth_aug_2019.pdf

33.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.5.5, Island Generation

2.33.6 Why was this assignment made?

RESPONSE:

BC Hydro assigned the gas transportation contract to Powerex in order to align the responsibility for covering the transportation costs with the party receiving the majority of the economic benefit.

Please also refer to the public version of Attachment 1 to BC Hydro's response to ZONE II RPG IR 1.6.1 for the business case on the assignment of the Westcoast T-South Transportation Service Agreement from BC Hydro to Powerex.

34.0 Reference: Exhibit B-6, BC Hydro response to CEABC 1.5.7, Market Constraints

In its response BC Hydro states: "During periods when BC Hydro is in a deficit position, Island Generation will generally be dispatched more often, when needed for reliability or when imports are limited by transmission or market constraints. In general, Island Generation is more expensive than market imports in part due to the BC Carbon tax."

2.34.1 Please describe in detail "market constraints".

RESPONSE:

Market constraints refer to any limitations on the availability of wholesale market supply.

In the context of BC Hydro's response to CEABC IR 1.5.7, we were referring to any situation where our expectation of the cost of imports (market price) to meet our deficit is greater than the cost of running Island Generation.

35.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.6.3, Glacier Melt

In its response BC Hydro provided information about the impact of climate change on glacier melt and projected increases in precipitation and runoff to large interior glaciated basins.

2.35.1 Does BC Hydro have any specific information about glacier melt and projected increases in precipitation and runoff in relation to the Bridge river system that is different than the general information provided with respect to large interior glaciated basins. If yes, please provide it.

RESPONSE:

BC Hydro and the Pacific Climate Impacts Consortium prepared a technical report "BC Hydro Bridge River System: Climate Change Summary Report on Future Projections of Climate and Inflows" in 2017 as part of the Bridge River Water Development Plan for the Application for Water Licence Renewal submitted to the BC Comptroller of Water Rights. This technical report summarized historical trends in climate and reservoir inflows and future projections of climate and streamflow, including glacier runoff, for the Bridge River watershed.

A copy of the report can be found at the following link.

36.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.6.9, Heritage Hydro Capability

In its response, BC Hydro said: "The heritage hydro capability used for BC Hydro's long term planning purposes was updated in 2018 to reflect the most current and planned system upgrade conditions since 2012".

2.36.1 Please provide the updated figures for all water conditions and a description and rationale for all the changes that were made.

RESPONSE:

In 2018, BC Hydro conducted a long-term planning study (based on average water planning criteria) for a future resource portfolio in 2027 that includes Site C. The average Heritage Resources capability (Hydro and Prince Rupert) from that study is 52,202 GWh, as can be seen in Table 1 of BC Hydro's response to BCUC IR 1.11.2.2.1 in the EPA Renewals for Sechelt Creek, Brown Lake Hydro and Walden North Hydro proceeding, a copy of which is provided as Attachment 1 to this response. The attached response provides a description of the changes made to the Heritage Resources capability when the long term planning study was updated in 2018.

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11.0 B. ECONOMIC ANALYSIS

Reference: BC HYDRO ENERGY/CAPACITY GAP
Exhibit B-1, p. 3; 2017 BCUC Site C Inquiry, Exhibit F1-1, pp. 7, 8, Exhibit A-24-2-1, Commission Illustrative Alternative Portfolio
Need for new resources

BC Hydro states on page 3 of the Application that based on the mid-level load forecast in the F2017-F2019 RRA, the LRB identifies a need for new resources in F2022.

1.11.2.2.1 Please provide an updated Table K-3 and K-4 above, using BC Hydro's most recent estimates for each row and explain any significant differences (Updated LRB).

RESPONSE:

Tables K-3 and K-4 provided in the BCUC Site C Inquiry only provide the LRB after planned resources. For completeness and for the purpose of answering other questions in this proceeding that refer to this response, we are providing the updates to the LRB tables both before and after planned resources (i.e., Tables K-1 to K-4 of the Site C Inquiry where Tables K-1 and K-2 do not include Site C, and Tables K-3 and K-4 include Site C). Please refer to Tables 1-4, which all include Site C, in section 3 below.

Tables 1-4 provide an updated LRB[1] that incorporates new and updated information as discussed more fully in section 1 below. This updated LRB is not a new long term load forecast. This update includes new supply information and incorporates adjustments to the May 2016 load forecast. The updated LRB in Table 1 below shows that the first year of LRB shortfall (before planned resources) has moved from fiscal 2022 (in the Application) to fiscal 2027.

Additional detailed information is provided below as follows: (1) new and updated information to the LRB; (2) the first year of deficit in the updated LRB; and (3) updated LRBs.

[1] BC Hydro notes in our applications subsequent to the F17-F19 RRA (i.e., BCUC Site C Inquiry [Tables K1-K4], Waneta 2017 Transaction), BC Hydro provided updates to the LRB which largely reflected revisions and re-allocations to certain values, and had no impact on the fiscal 2022 LRB shortfall.

SECTION 1: New and Updated Information

The key updates to the LRBs reflected in Tables 1-4 include:

a) Adjustments to the May 2016 Load Forecast;

b) Updates to our existing and committed resources; and

c) Updates to our planned resources (shown in Tables 3 and 4 only).

a) Adjustments to the May 2016 Load Forecast

BC Hydro's new long term load forecast has not yet been completed. However, we have made some updates to the May 2016 long term load forecast in response to certain issues raised previously by the BCUC that could be easily incorporated. Specifically, the following adjustments have been made:

- **The price elasticity factor has been updated from -0.05 to -0.1, based on findings of an electricity price elasticity study conducted by a third party consultant;**
- **Updated methodology and new information on LNG and LNG uncertainty bands, and**
- **Updated DSM plan developed for the F20-F21 RRA.**

Figure 1 below presents the May 2016 Load Forecast and the adjusted May 2016 Load Forecast for energy with their respective uncertainty bands. This figure also includes BC Hydro's short-term mid-load forecast (fiscal 2019 to fiscal 2024) from the F20-F21 RRA (October 2018 Load Forecast).[2] Figure 2 below presents a similar view for peak demand without a short term forecast. BC Hydro considers the adjusted May 2016 forecast is reasonable for the following reasons:

- **Although the short-term October 2018 Load Forecast suggests more modest load growth relative to the May 2016 forecast, it remains within the May 2016 forecast's band of uncertainty; and**
- **The adjusted May 2016 load forecast has not incorporated potential load growth of the CleanBC Plan announced on December 5, 2018 which is expected to increase demand due to electrification.**

2 The methodology used to develop this short term forecast addresses many of the issues raised previously by the BCUC.

b) Updates to existing and committed resources

The updated LRB reflects changes to existing and committed resources relative to the information provided in the Tables K-1 to K-4 (and the Tables 3-6 to 3-9 in the F17-F19 RRA), including the following:

- **The Heritage system capability has been updated to reflect new information, such as facility upgrades, major outage assumptions, Treaty and operational assumptions, and updated water records. BC Hydro notes that the Waneta 2017 Transaction, completed in 2018, does not impact the LRB as the lease with Teck extends past the forecast period;**

- **Future energy savings from codes and standards have been reallocated to existing and committed (i.e., were previously planned resources);**

- **The IPP forecast was updated from May 2016 to October 2018 to reflect updated IPP operational history and other expected changes to operations; and**

- **New EPAs, such as EPA renewals, and SOP EPAs that have been reallocated to existing and committed (i.e., were previously planned resources).**

BC Hydro notes that these changes to existing and committed resources are consistent with the information provided in the F20-F21 RRA.

c) Updates to planned resources

The updated LRB reflects the following material updates to planned resources relative to the information provided in Tables K-1 to K-4 (and the Tables 3-6 to 3-9 in the F17-F19 RRA):

- ***EPA renewals*. In addition to the IPP forecast updates discussed above, as a result of the recently announced Biomass Energy Program, which is part of Phase 1 of Government's Comprehensive Review, the renewal assumption for seven biomass projects has increased from 50 per cent to 80 per cent for energy, and from 50 per cent to 100 per cent for capacity. For all the other EPA renewals (including those biomass projects that are not eligible to participate in the Biomass Energy Program), the renewal percentage assumptions have not been changed to reflect the recent decision to use market price as an interim assumption for cost effectiveness. As such, these assumptions remain the same as in the BC Hydro May 2016 IPP forecast; and**

- ***Expected SOP and other First Nations commitments.* The Standing Offer Program (SOP) has been indefinitely suspended and accordingly SOP**

volumes have been reduced, with the exception of four First Nations clean energy projects under the SOP[3] and three other potential EPAs related to Impact Benefit Agreements with First Nations.

BC Hydro notes that these changes to planned resources are consistent with the information provided in the F20-F21 RRA.

SECTION 2: The First Year of Deficit in the Updated LRB

Table 1 demonstrates that the first year of energy deficit in the updated LRB is in fiscal 2027 (line 8 "surplus/(deficit)" of Table 1). Table 2 demonstrates that the first year of capacity deficit in the updated LRB is in fiscal 2023 (line 9 "surplus/(deficit)" of Table 2). BC Hydro notes that when evaluating the need for energy resources, such as EPA renewals:

- **The planning view of the LRB is applicable and is used to determine the first year of deficit. For an explanation of planning vs. operational view please see Appendix B of the Application; and**

- **The LRB (before planned resources) - i.e., Table 1 – is applicable because all planned resources, including EPA renewals, are not committed. Table 3 (after planned resources) would be used for determining the need for a resource that is not included in our planned resources.[4]**

SECTION 3: BC HYDRO'S UPDATED LOAD RESOURCE BALANCE TABLES

As discussed above,

- **Tables 1 to 4 show the planning view of the updated LRB;**

- **Tables 1 and 2 show the LRB with only existing and committed resources (before planned resources); and**

- **Tables 3 and 4 show the LRB after planned resources.**

---

3 There are five excepted First Nation clean energy projects; one EPA has already been signed and is now an existing and committed resource.

4 Please note that Tables K-3 and K-4 from the Site C Inquiry, similar to Table 3 and Table 4 (both after planned resources), would also not be applicable because they include planned resources.

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Table 1 Planning view of energy load resource balance based on existing and committed resources

	(GWh)		F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
	Existing and Committed Heritage Resources																		
1	Heritage Resources (including Site C)	(a)	46,916	46,916	46,916	46,916	47,282	50,808	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202
2	***Existing and Committed IPP Resources***	(b)	16,898	16,607	16,293	14,173	13,762	13,511	13,221	13,113	13,006	12,537	11,766	11,229	10,949	10,824	10,518	9,809	8,283
3	**Total Supply (Planning View)**	(c) = a + b	63,814	63,523	63,209	61,089	61,043	64,319	65,423	65,315	65,208	64,739	63,968	63,431	63,151	63,026	62,720	62,011	60,485
	Demand - Integrated System Total Gross Requirements																		
4	Adjusted 2016 May Mid Load Forecast Before DSM (with -0.1 elasticity)	(d)	(61,129)	(62,066)	(63,444)	(64,672)	(66,252)	(68,201)	(69,563)	(71,047)	(72,030)	(72,990)	(74,057)	(75,128)	(76,283)	(77,204)	(78,129)	(78,946)	(79,815)
	Existing and Committed Demand Side Management & Others Measures																		
5	F16-F19 DSM Portfolio Savings - F20-F21 RRA		2,557	2,463	2,388	2,352	2,332	2,311	2,274	2,235	2,194	2,148	2,111	2,050	1,964	1,884	1,766	1,678	1,577
6	F20+ Codes & Standards - F20-F21 RRA and Voltage and VAR Optimization		220	617	967	1,238	1,483	1,715	1,921	2,108	2,271	2,427	2,583	2,724	2,853	2,982	3,110	3,240	3,368
7	Sub-total	(e)	2,777	3,080	3,355	3,590	3,815	4,026	4,195	4,343	4,465	4,575	4,694	4,774	4,817	4,866	4,876	4,918	4,945
8	**Surplus / (Deficit)**	(f) = c + d + e	**5,461**	**4,538**	**3,120**	**7**	**(1,393)**	**144**	**55**	**(1,389)**	**(2,357)**	**(3,675)**	**(5,395)**	**(6,923)**	**(8,315)**	**(9,312)**	**(10,533)**	**(12,018)**	**(14,384)**
9	**Surplus / Deficit as % of Net Load**		**109%**	**108%**	**105%**	**100%**	**98%**	**100%**	**100%**	**98%**	**97%**	**95%**	**92%**	**90%**	**88%**	**87%**	**86%**	**84%**	**81%**
10	**Small Gap Surplus / (Deficit)**		**8,849**	**8,362**	**7,404**	**4,654**	**3,711**	**5,782**	**5,988**	**4,758**	**4,037**	**2,978**	**1,519**	**216**	**(841)**	**(1,587)**	**(2,632)**	**(3,848)**	**(5,987)**
11	**Large Gap Surplus / (Deficit)**		**1,125**	**(296)**	**(2,363)**	**(6,947)**	**(8,637)**	**(7,382)**	**(8,106)**	**(9,846)**	**(11,144)**	**(12,874)**	**(15,054)**	**(16,846)**	**(18,518)**	**(19,773)**	**(21,267)**	**(23,032)**	**(25,694)**

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Table 2 Peak capacity load resource balance based on existing and committed resources

	(MW)		F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
	Existing and Committed Heritage Resources																		
1	Heritage Hydroelectric (including Site C)	(a)	11,588	11,588	11,588	11,528	11,588	12,319	12,319	12,676	12,676	12,676	12,676	12,676	12,262	12,262	12,733	12,733	12,733
2	***Existing and Committed IPP Resources***	(b)	1,536	1,455	1,482	1,207	1,196	1,136	1,104	1,104	1,091	1,080	948	912	908	884	835	590	517
3	14% of Supply Requiring Reserves - excl. Rio Tinto Alcan and FortisBC	(c)	(1,808)	(1,796)	(1,792)	(1,745)	(1,752)	(1,853)	(1,848)	(1,898)	(1,897)	(1,895)	(1,877)	(1,871)	(1,813)	(1,810)	(1,869)	(1,865)	(1,855)
4	**Effective Load Carrying Capability**	(d) = a + b + c	11,317	11,246	11,278	10,990	11,032	11,602	11,575	11,882	11,870	11,861	11,748	11,716	11,357	11,336	11,699	11,458	11,395
	Demand - Integrated System Total Gross Requirements																		
5	Adjusted 2016 May Mid Load Forecast Before DSM (with -0.1 elasticity)	(e)	(11,340)	(11,502)	(11,704)	(11,930)	(12,260)	(12,508)	(12,709)	(12,900)	(13,133)	(13,345)	(13,574)	(13,801)	(14,026)	(14,257)	(14,485)	(14,723)	(14,953)
	Existing and Committed Demand Side Management & Others Measures																		
6	F16-F19 DSM Portfolio Savings - F20-F21 RRA		476	465	451	442	435	426	417	407	398	387	378	367	352	338	325	315	301
7	F20+ Codes & Standards - F20-F21 RRA		43	129	198	246	288	327	360	390	416	440	463	484	503	521	544	568	591
8	Sub-total	(f)	519	594	649	688	723	753	777	797	814	827	841	851	855	859	869	883	892
9	**Surplus / (Deficit)****	(g) = d + e + f	**496**	**338**	**223**	**(251)**	**(505)**	**(153)**	**(357)**	**(221)**	**(449)**	**(657)**	**(985)**	**(1,234)**	**(1,813)**	**(2,062)**	**(1,917)**	**(2,382)**	**(2,666)**
10	**Surplus / Deficit as % of Net Load ****		**105%**	**103%**	**102%**	**98%**	**96%**	**99%**	**97%**	**98%**	**96%**	**95%**	**92%**	**90%**	**86%**	**85%**	**86%**	**83%**	**81%**
11	**Small Gap Surplus / (Deficit)****		**1,111**	**1,031**	**1,002**	**611**	**427**	**857**	**708**	**886**	**710**	**556**	**282**	**80**	**(435)**	**(628)**	**(444)**	**(850)**	**(1,083)**
12	**Large Gap Surplus / (Deficit)****		**(318)**	**(574)**	**(859)**	**(1,528)**	**(1,822)**	**(1,564)**	**(1,863)**	**(1,756)**	**(2,045)**	**(2,322)**	**(2,735)**	**(3,034)**	**(3,666)**	**(3,969)**	**(3,882)**	**(4,411)**	**(4,760)**

** Capacity load resource balances are only shown in Planning View.

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Table 3 Planning view of the energy load resource balance after planned resources

	(GWh)		F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
1	***Existing and Committed Heritage Resources (incl. Site C)***	(a)	46,916	46,916	46,916	46,916	47,282	50,808	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202	52,202
2	***Existing and Committed IPP Resources***	(b)	16,898	16,607	16,293	14,173	13,762	13,511	13,221	13,113	13,006	12,537	11,766	11,229	10,949	10,824	10,518	9,809	8,283
	Future Supply-Side Resources																		
3	IPP Renewals		593	1,105	1,201	3,430	3,789	3,990	4,267	4,350	4,434	4,838	5,365	5,829	5,963	6,003	6,241	6,889	8,177
4	Expected SOP Projects and other First Nations Commitments		67	145	226	226	226	226	226	226	226	226	226	226	226	226	226	226	226
5	Rev 6		-	-	-	-	-	-	-	-	-	-	11	26	26	26	26	26	26
6	Sub-total	(c)	659	1,250	1,427	3,656	4,015	4,216	4,493	4,576	4,660	5,064	5,602	6,081	6,215	6,255	6,493	7,141	8,429
7	**Total Supply (Planning View)**	(d) = a + b + c	64,473	64,774	64,635	64,745	65,058	68,535	69,916	69,891	69,868	69,804	69,570	69,512	69,366	69,280	69,213	69,152	68,914
	Demand - Integrated System Total Gross Requirements																		
8	Adjusted 2016 May Mid Load Forecast Before DSM (with -0.1 elasticity)	(e)	(61,129)	(62,066)	(63,444)	(64,672)	(66,252)	(68,201)	(69,563)	(71,047)	(72,030)	(72,990)	(74,057)	(75,128)	(76,283)	(77,204)	(78,129)	(78,946)	(79,815)
	Existing and Committed Demand Side Management & Others Measures																		
9	F16-F19 DSM Portfolio Savings - F20-F21 RRA		2,557	2,463	2,388	2,352	2,332	2,311	2,274	2,235	2,194	2,148	2,111	2,050	1,964	1,884	1,766	1,678	1,577
10	F20+ Codes & Standards - F20-F21 RRA and Voltage and VAR Optimization		220	617	967	1,238	1,483	1,715	1,921	2,108	2,271	2,427	2,583	2,724	2,853	2,982	3,110	3,240	3,368
	Planned Demand Side Management Measures																		
11	F20+ Rates - F20-F21 RRA		64	129	145	149	145	142	140	139	137	137	136	136	136	136	136	136	136
12	F20+ Programs - F20-F21 RRA		128	382	570	699	833	954	1,070	1,187	1,298	1,397	1,492	1,510	1,515	1,561	1,592	1,619	1,632
13	Sub-total	(f)	2,969	3,591	4,070	4,438	4,793	5,122	5,405	5,669	5,900	6,109	6,322	6,420	6,468	6,563	6,604	6,673	6,713
14	**Surplus / (Deficit)**	(g) = d + e + f	**6,313**	**6,299**	**5,261**	**4,511**	**3,600**	**5,456**	**5,758**	**4,514**	**3,738**	**2,923**	**1,835**	**804**	**(449)**	**(1,361)**	**(2,312)**	**(3,122)**	**(4,187)**
15	**Surplus / Deficit as % of Net Load**		**111%**	**111%**	**109%**	**107%**	**106%**	**109%**	**109%**	**107%**	**106%**	**104%**	**103%**	**101%**	**99%**	**98%**	**97%**	**96%**	**94%**
16	**Small Gap Surplus / (Deficit)**		**9,682**	**10,071**	**9,473**	**9,071**	**8,604**	**10,983**	**11,569**	**10,526**	**9,986**	**9,420**	**8,584**	**7,776**	**6,857**	**6,191**	**5,411**	**4,865**	**4,025**
17	**Large Gap Surplus / (Deficit)**		**1,957**	**1,413**	**(294)**	**(2,530)**	**(3,744)**	**(2,181)**	**(2,526)**	**(4,078)**	**(5,195)**	**(6,432)**	**(7,989)**	**(9,286)**	**(10,819)**	**(11,995)**	**(13,225)**	**(14,319)**	**(15,682)**

Table 4 Peak capacity load resource balance after planned resources

	(MW)		F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
	Existing and Committed Heritage Resources																		
1	Heritage Hydroelectric	(a)	11,588	11,588	11,588	11,528	11,588	12,319	12,319	12,676	12,676	12,676	12,676	12,676	12,262	12,262	12,733	12,733	12,733
2	***Existing and Committed IPP Resources***	(b)	1,536	1,455	1,482	1,207	1,196	1,136	1,104	1,104	1,091	1,080	948	912	908	884	835	590	517
	Future Supply-Side Resources																		
3	IPP Renewals		143	225	254	529	538	547	576	576	586	597	662	640	628	643	680	925	966
4	Expected SOP Projects and other First Nations Commitments		12	12	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
5	REV 6		0	0	0	0	0	0	0	0	0	0	488	488	488	488	488	488	488
6	Sub-total	(c)	155	236	273	548	557	566	594	595	605	616	1,169	1,147	1,135	1,150	1,187	1,432	1,473
7	14% of Supply Requiring Reserves - excl. Rio Tinto Alcan and FortisBC	(d)	(1,829)	(1,829)	(1,830)	(1,822)	(1,830)	(1,932)	(1,932)	(1,982)	(1,981)	(1,981)	(2,040)	(2,032)	(1,972)	(1,971)	(2,035)	(2,066)	(2,061)
8	**Effective Load Carrying Capability**	(e) = a+b+c+d	11,450	11,450	11,513	11,461	11,512	12,088	12,086	12,393	12,390	12,390	12,753	12,702	12,334	12,326	12,720	12,689	12,662
	Demand - Integrated System Peak																		
9	Adjusted 2016 May Mid Load Forecast Before DSM (with -0.1 elasticity)	(f)	(11,340)	(11,502)	(11,704)	(11,930)	(12,260)	(12,508)	(12,709)	(12,900)	(13,133)	(13,345)	(13,574)	(13,801)	(14,026)	(14,257)	(14,485)	(14,723)	(14,953)
	Existing and Committed Demand Side Management & Others Measures																		
10	F16-F19 DSM Portfolio Savings - F20-F21 RRA		476	465	451	442	435	426	417	407	398	387	378	367	352	338	325	315	301
11	F20+ Codes & Standards - F20-F21 RRA		43	129	198	246	288	327	360	390	416	440	463	484	503	521	544	568	591
	Planned Demand Side Management Measures																		
12	F20+ Rates - F20-F21 RRA		8	15	17	17	17	16	16	15	15	15	15	15	14	14	14	14	14
13	F20+ Programs - F20-F21 RRA		19	58	87	108	129	148	166	183	199	213	225	229	232	237	244	250	254
14	Sub-total	(g)	546	667	753	813	869	917	959	995	1,028	1,055	1,081	1,095	1,101	1,110	1,127	1,147	1,160
15	**Surplus / (Deficit)****	(h) = e + f + g	**656**	**615**	**562**	**345**	**121**	**497**	**336**	**488**	**285**	**101**	**260**	**(3)**	**(591)**	**(822)**	**(638)**	**(887)**	**(1,131)**
16	**Surplus / Deficit as % of Net Load ****		**106%**	**106%**	**105%**	**103%**	**101%**	**104%**	**103%**	**104%**	**102%**	**101%**	**102%**	**100%**	**95%**	**94%**	**95%**	**93%**	**92%**
17	**Small Gap Surplus / (Deficit)****		**1,268**	**1,298**	**1,327**	**1,192**	**1,034**	**1,488**	**1,380**	**1,573**	**1,420**	**1,288**	**1,501**	**1,284**	**761**	**586**	**808**	**617**	**422**
18	**Large Gap Surplus / (Deficit)****		**(161)**	**(307)**	**(534)**	**(947)**	**(1,214)**	**(933)**	**(1,192)**	**(1,069)**	**(1,335)**	**(1,590)**	**(1,516)**	**(1,831)**	**(2,470)**	**(2,754)**	**(2,630)**	**(2,944)**	**(3,254)**

Figure 1 Comparison of load forecasts for energy. All forecasts are after DSM and with LNG.

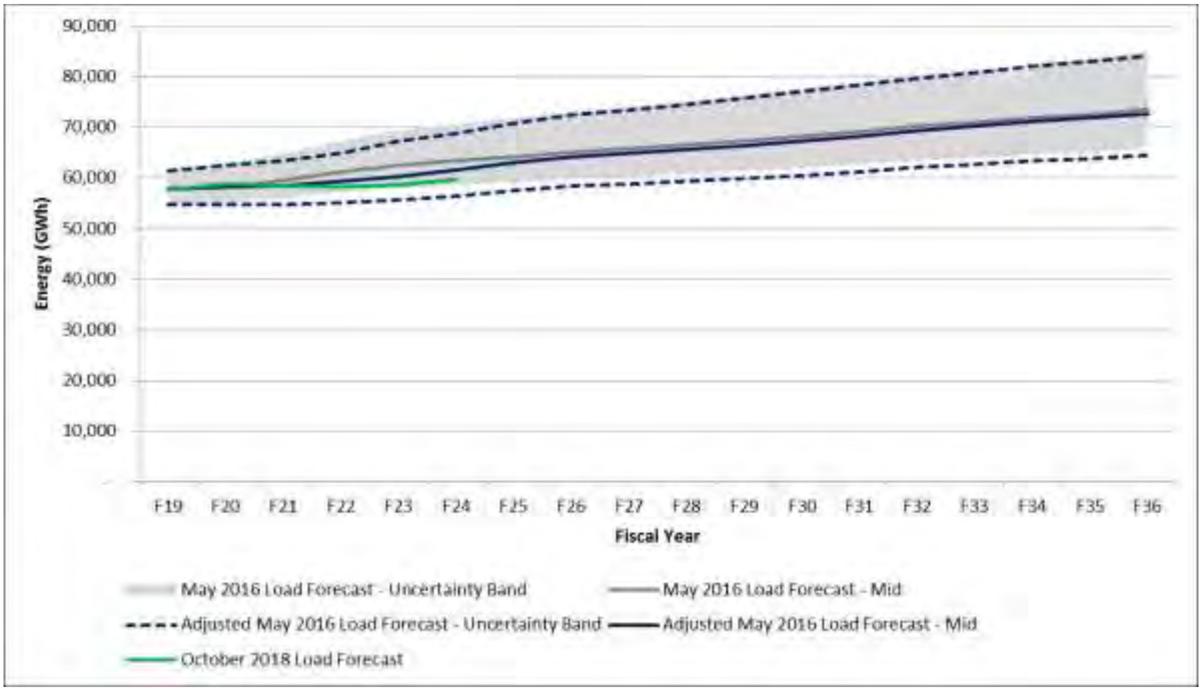
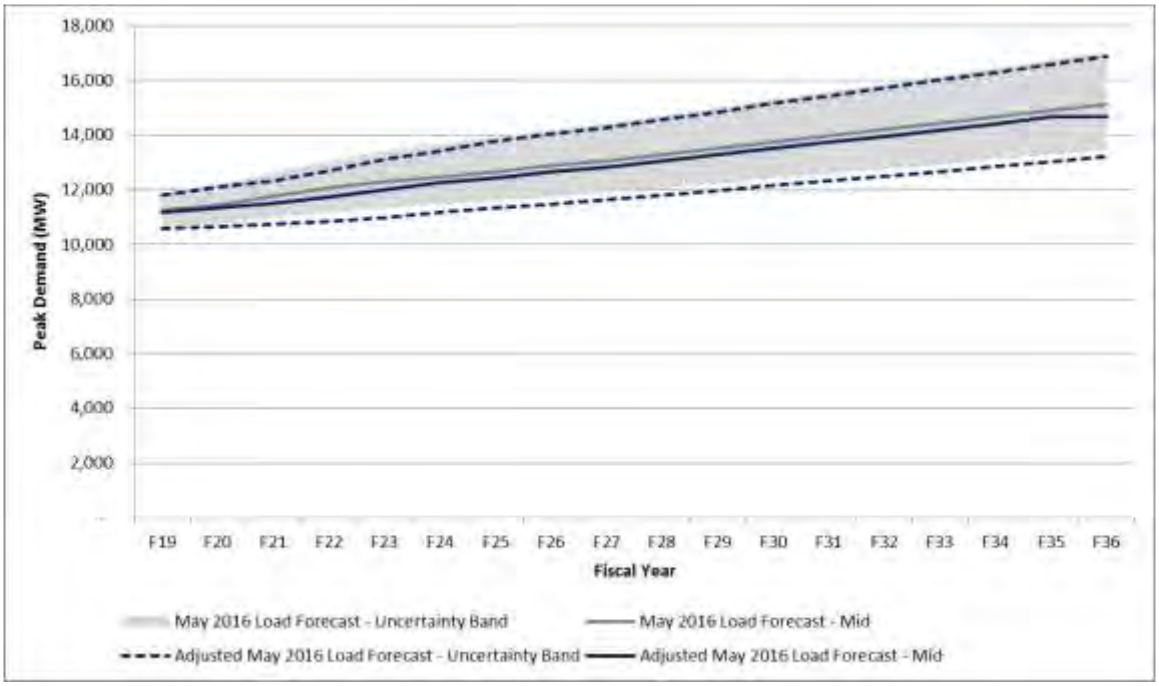


Figure 2 Comparison of load forecasts for peak demand. All forecasts are after DSM and with LNG.



37.0 Reference: Exhibit B-6, BC Hydro's response to CEABC IR 1.8.5, transmission constraints that may potentially limit energy imports.

In its response to CEABC IR 1.8.5, BC Hydro provided some general information about potential transmission constraints that may limit it capability to import electrical energy into British Columbia in the event of a significant shortfall in generation. There are many risks to the generation capabilities within British Columbia. Among these would be included:

- A "critical water" sequence could reduce the Heritage Generation on the order of 5,600 GWh relative to the planned generation, which is based on "average water";
- Purchases from Alcan will likely be on the order of 800 GWh, or less, rather than its 3,300 GWh of theoretical energy;
- Purchases from IPPs could be reduced by 800 to 1,000 GWh (as per the response to AMPC IR 1.15.7.1) or less, especially during the critical water period;
- Some of the Heritage hydro generation, and some of the IPP generation might be produced during times of inadequate load and would have to be exported rather than serving load. (Even in a year of scarcity such as F2019, BC Hydro was forced to sell 760 GWh that could not be used to serve domestic load.)
- Island Generation cannot generate its theoretical 2,300 GWh if the gas is unavailable or the gas transmission capacity is curtailed or assigned elsewhere;
- GWhrs "Forced Out of Service" could approach 2,000 GWh or more (as shown in the response to AMPC IR 1.19.1)

If such a combination of generation shortfalls were to take place, BC Hydro could find itself in a position far worse than what it experienced in the winter of F2019, needing to acquire more than 13,000 GWh of imported energy. If such a shortfall occurred, most of the needed energy would have to be imported over the BC US interconnection, with smaller amounts possible from Alberta.

2.37.1 In each of the past 4 years (F2016-F2019) how many MWhrs of import transmission capacity has been available over the BC–US and the Alberta interconnections, during Light Load Hours ("LLH"), at times when BC Hydro's load was also adequate to accept those imports? (i.e. there was sufficient load and also the capability to turn down domestic generation)

RESPONSE:

This answer also responds to CEABC IRs 2.37.2 and 2.37.3.

The preamble to the question assumes a hypothetical scenario with a number of related and unrelated risks to generating resources occurring simultaneously that are combined in such a way that it implies a requirement for BC Hydro to be able to import more than 13,000 GWh over one year. During time periods where there is a risk of generation shortfall, BC Hydro would plan for and adequately mitigate each risk. Generally, BC Hydro has seen sufficient transmission capability to allow for energy imports to meet its needs across the combined U.S. and Alberta interties.

The table below provides an historical view (past four fiscal years) and forecast (next five fiscal years) of the total import transmission capability of the combined US and Alberta interties.

Total Import Transmission Capability* (GWh)	F2016	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024
Heavy Load Hours (4920 Hours)	10,141	10,562	11,845	12,443	12,443	12,443	12,443	12,443	12,443
Light Load Hours (3840 Hours)	8,141	8,351	9,315	9,800	9,800	9,800	9,800	9,800	9,800
Total (HLH + LLH) (GWh)	**18,282**	**18,913**	**21,160**	**22,243**	**22,243**	**22,243**	**22,243**	**22,243**	**22,243**

* Excludes long term commitments for wheelthroughs

BC Hydro would like to clarify the following points in the preamble to the question:

- **Critical Water: the 5,600 GWh quoted from BC Hydro's response to CEABC IR 1.6.6 also reflected additional system capability from system changes which occurred between the introduction of Special Direction 10 and the amendment to Special Direction 10. BC Hydro's response to CEABC IR 2.30.1 states that the change to "average water" effectively increased the generation that would be assumed from the Heritage Assets by 4,100 GWh/year;**

- **Rio Tinto Alcan: an annual shortfall in purchases from Rio Tinto Alcan cannot exceed 1,700 GWh which is BC Hydro's long-term operational view of Tier 1 and Tier 2 deliveries. Please refer to BC Hydro's response to CEABC IR 2.32.3;**

- **IPP energy: the variability of IPP generation and its usefulness in contributing to firm energy will be reviewed as part of the 2021 IRP;**

- **Island Generation: as described in BC Hydro's response to CEABC IR 2.33.2, BC Hydro holds a gas Transportation Service Agreement with FortisBC; and**

- **BC Hydro Forced Outages: the metric of GWhrs Forced Out of Service quoted from the Generation Strategic Asset Plan provided in BC Hydro's response to AMPC IR 1.19.1 is a fleet level performance metric used to track trends, and is an alternative to the utility standard Forced Outage Factor. As described in the report, it is used because for the Forced Outage Factor "a 50 hour forced outage of a 450 MW Mica unit has the same forced outage factor as a 50 hour forced outage of a 9 MW Aberfieldie unit." The metric does not imply a loss of energy from the system. For example, a unit outage at Mica won't cause a loss of energy unless the reservoir is full and close to spilling. Therefore, this quantity does not constitute energy that would need to be replaced by imports.**

37.0 Reference: Exhibit B-6, BC Hydro's response to CEABC IR 1.8.5, transmission constraints that may potentially limit energy imports.

In its response to CEABC IR 1.8.5, BC Hydro provided some general information about potential transmission constraints that may limit it capability to import electrical energy into British Columbia in the event of a significant shortfall in generation. There are many risks to the generation capabilities within British Columbia. Among these would be included:

- A "critical water" sequence could reduce the Heritage Generation on the order of 5,600 GWh relative to the planned generation, which is based on "average water";
- Purchases from Alcan will likely be on the order of 800 GWh, or less, rather than its 3,300 GWh of theoretical energy;
- Purchases from IPPs could be reduced by 800 to 1,000 GWh (as per the response to AMPC IR 1.15.7.1) or less, especially during the critical water period;
- Some of the Heritage hydro generation, and some of the IPP generation might be produced during times of inadequate load and would have to be exported rather than serving load. (Even in a year of scarcity such as F2019, BC Hydro was forced to sell 760 GWh that could not be used to serve domestic load.)
- Island Generation cannot generate its theoretical 2,300 GWh if the gas is unavailable or the gas transmission capacity is curtailed or assigned elsewhere;
- GWhrs "Forced Out of Service" could approach 2,000 GWh or more (as shown in the response to AMPC IR 1.19.1)

If such a combination of generation shortfalls were to take place, BC Hydro could find itself in a position far worse than what it experienced in the winter of F2019, needing to acquire more than 13,000 GWh of imported energy. If such a shortfall occurred, most of the needed energy would have to be imported over the BC US interconnection, with smaller amounts possible from Alberta.

2.37.2 Was the amount of LLH transmission capacity adequate to accept up to 13,000 GWh of imported energy in each of the past 4 years? And is it expected to be adequate in each of the next 5 years?

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.37.1.

37.0 Reference: Exhibit B-6, BC Hydro's response to CEABC IR 1.8.5, transmission constraints that may potentially limit energy imports.

In its response to CEABC IR 1.8.5, BC Hydro provided some general information about potential transmission constraints that may limit it capability to import electrical energy into British Columbia in the event of a significant shortfall in generation. There are many risks to the generation capabilities within British Columbia. Among these would be included:

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If such a combination of generation shortfalls were to take place, BC Hydro could find itself in a position far worse than what it experienced in the winter of F2019, needing to acquire more than 13,000 GWh of imported energy. If such a shortfall occurred, most of the needed energy would have to be imported over the BC US interconnection, with smaller amounts possible from Alberta.

2.37.3 If transmission capacity was not adequate during LLH periods, then how much capacity was available during HLH periods? Would this additional capacity have allowed BC Hydro to import up to 13,000 GWh in each of the past 4 years? And is it expected to allow such an import level in each of the next 5 years?

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.37.1.

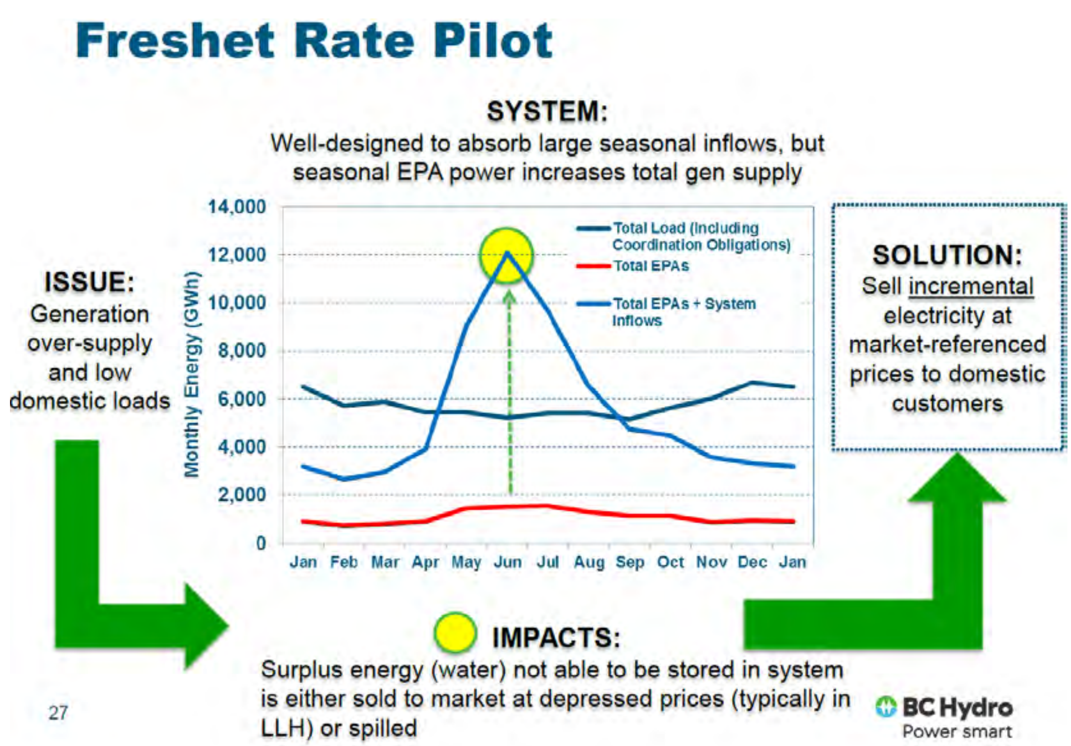
38.0 Reference: Exhibit B-6, BC Hydro's response to CEABC IR 1.7.2, discussing surplus sales during 2018.

In its response, BC Hydro makes the statement:

"BC Hydro engaged in surplus sales during 2018 (calendar year). Forced surplus sales of 760 GWh were made in May and June 2018, at an average price of $5 per MWh. These sales were required due to a surplus of energy from IPPs and other run of river and must-run resources that collectively required the sales to balance the load.

When BC Hydro conducted its energy studies in June 2018, it was still projecting a surplus for the fiscal year. In July and August 2018, BC Hydro engaged in surplus sales that were appropriate given the information known at the time… The sales that BC Hydro made in July and August 2018 captured the very high prices that materialized in those months. The actual volume of surplus sales in July and August 2018 was 1470 GWh at an average price of $76 per MWh."

The problem of surplus energy in the May June period was further highlighted in the following chart presented at the October 11, 2018 Transmission Service Rate Design Workshop:



This chart appears to show an exceptionally large amount of surplus energy potentially generated over the months from May to August, some due to an increase in the energy from EPAs, but most of it due to an increase in the energy generated by other must-run resources.

2.38.1 Does the term “other run-of-river and must-run resources” refer to BC Hydro’s Heritage hydro generation? If not, what are these resources? Please list any that are not Heritage generation assets.

RESPONSE:

Yes, “other run-of-river and must-run resources” in BC Hydro’s response to CEABC IR 1.7.2 refers to the heritage hydro assets.

Please refer to BC Hydro’s response to CEABC IR 2.38.4 where we clarify that the chart referred to in the preamble depicts the total monthly energy equivalent system inflows and EPA deliveries. It does not reflect only must-run resources.

38.0 Reference: Exhibit B-6, BC Hydro's response to CEABC IR 1.7.2, discussing surplus sales during 2018.

In its response, BC Hydro makes the statement:

"BC Hydro engaged in surplus sales during 2018 (calendar year). Forced surplus sales of 760 GWh were made in May and June 2018, at an average price of $5 per MWh. These sales were required due to a surplus of energy from IPPs and other run of river and must-run resources that collectively required the sales to balance the load.

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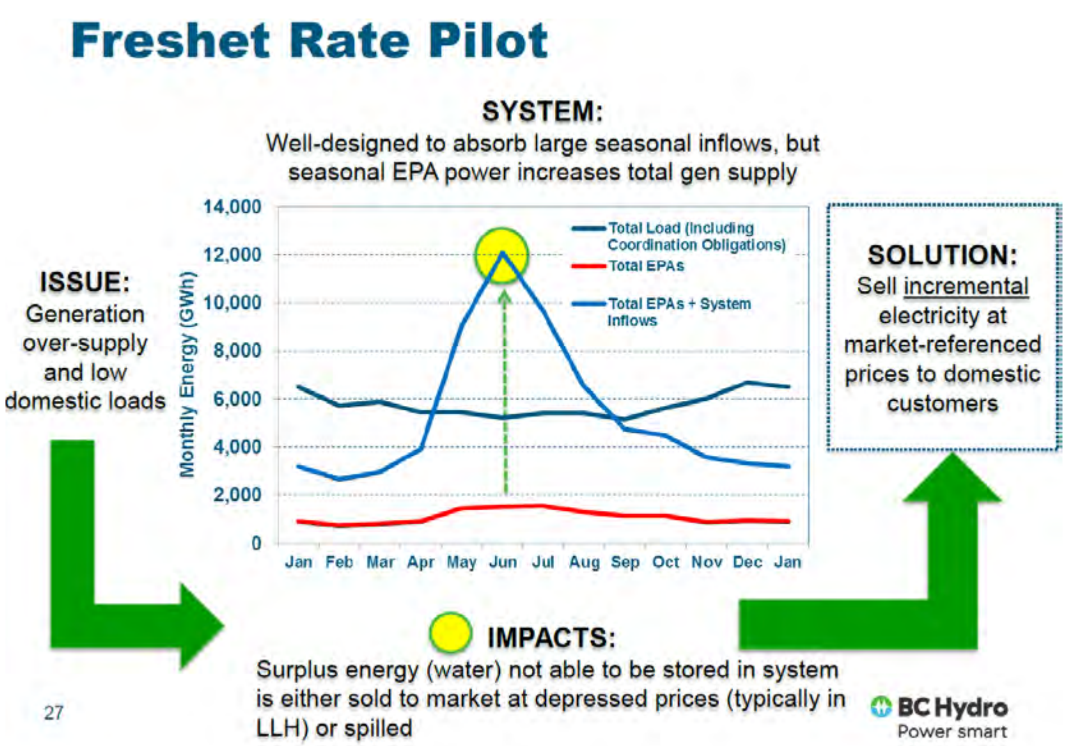

This chart appears to show an exceptionally large amount of surplus energy potentially generated over the months from May to August, some due to an increase in the energy from EPAs, but most of it due to an increase in the energy generated by other must-run resources.

2.38.2 Two average prices were quoted in the response to IR 1.7.2 (i.e. the $5 and $76 per MWh). Were these the prices that Powerex paid to BC Hydro, or the prices that Powerex received on the market? Are they in US or Canadian dollars? Do they include wheeling charges and losses?

RESPONSE:

The averages are based on prices that BC Hydro received from Powerex based on the Transfer Pricing Agreement in Canadian dollars (i.e. the applicable HLH and/or LLH Mid-C index price adjusted for wheeling charges and losses).

38.0 Reference: Exhibit B-6, BC Hydro's response to CEABC IR 1.7.2, discussing surplus sales during 2018.

In its response, BC Hydro makes the statement:

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When BC Hydro conducted its energy studies in June 2018, it was still projecting a surplus for the fiscal year. In July and August 2018, BC Hydro engaged in surplus sales that were appropriate given the information known at the time… The sales that BC Hydro made in July and August 2018 captured the very high prices that materialized in those months. The actual volume of surplus sales in July and August 2018 was 1470 GWh at an average price of $76 per MWh."

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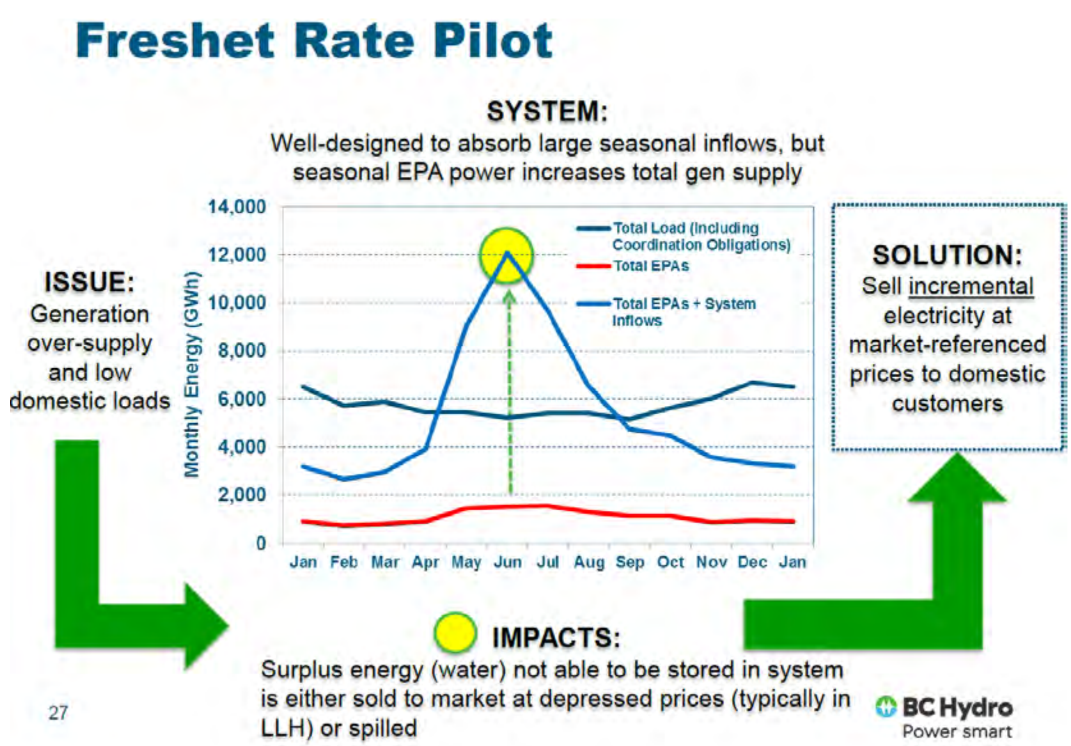

This chart appears to show an exceptionally large amount of surplus energy potentially generated over the months from May to August, some due to an increase in the energy from EPAs, but most of it due to an increase in the energy generated by other must-run resources.

2.38.3 How much energy did Powerex import during each of the months May to August, 2018, for either domestic or trade purposes, while it was simultaneously exporting the amounts quoted in the response?

RESPONSE:

The information requested is provided as Attachment 1 to BC Hydro's response to CEABC IR 2.43.1. Please refer to fiscal 2019 in the table in the Attachment.

38.0 Reference: Exhibit B-6, BC Hydro's response to CEABC IR 1.7.2, discussing surplus sales during 2018.

In its response, BC Hydro makes the statement:

"BC Hydro engaged in surplus sales during 2018 (calendar year). Forced surplus sales of 760 GWh were made in May and June 2018, at an average price of $5 per MWh. These sales were required due to a surplus of energy from IPPs and other run of river and must-run resources that collectively required the sales to balance the load.

When BC Hydro conducted its energy studies in June 2018, it was still projecting a surplus for the fiscal year. In July and August 2018, BC Hydro engaged in surplus sales that were appropriate given the information known at the time… The sales that BC Hydro made in July and August 2018 captured the very high prices that materialized in those months. The actual volume of surplus sales in July and August 2018 was 1470 GWh at an average price of $76 per MWh."

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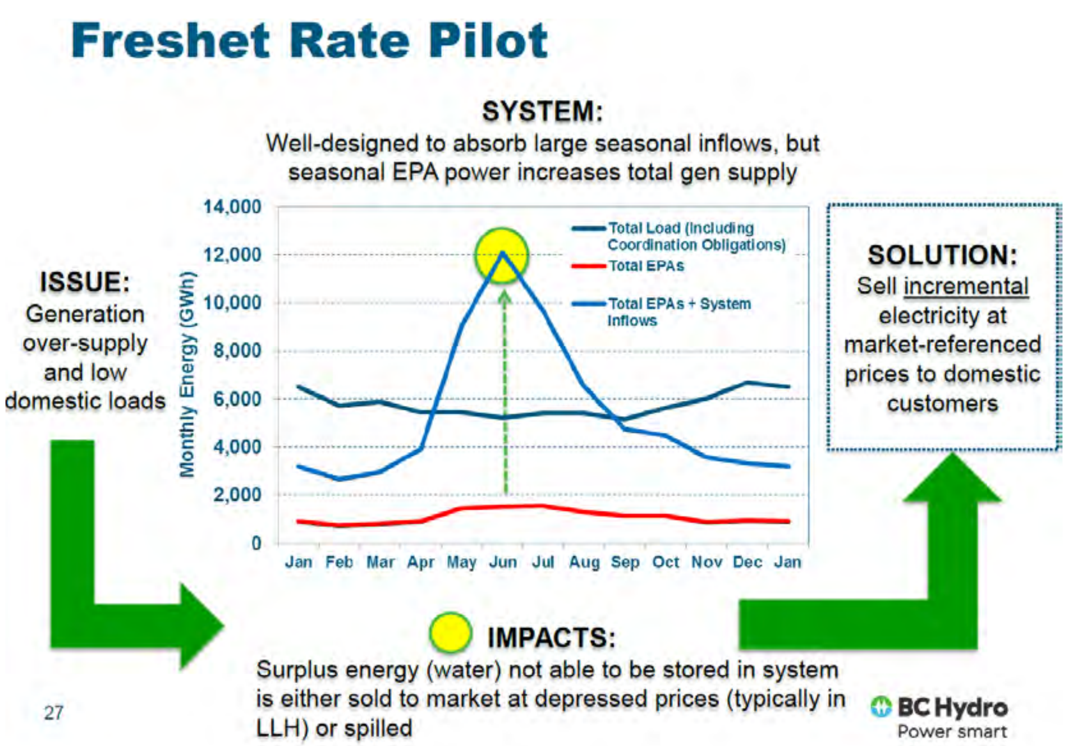

This chart appears to show an exceptionally large amount of surplus energy potentially generated over the months from May to August, some due to an increase in the energy from EPAs, but most of it due to an increase in the energy generated by other must-run resources.

2.38.4 The surplus indicated in the chart above would amount to in excess of 11,000 GWh, between May and August, and yet BC Hydro only describes the sale of 2,100 GWh during those months of 2018. Please confirm that this chart is merely indicative of the hypothetically possible generation, and that the chart does not represent the actual generation or load in any particular year.

RESPONSE:

The chart referred to in the preamble from the October 2018 Transmission Service Rate Design workshop depicts the total monthly energy equivalent system inflows and EPA inflows, which is not the actual or hypothetical generation.

38.0 Reference: Exhibit B-6, BC Hydro's response to CEABC IR 1.7.2, discussing surplus sales during 2018.

In its response, BC Hydro makes the statement:

"BC Hydro engaged in surplus sales during 2018 (calendar year). Forced surplus sales of 760 GWh were made in May and June 2018, at an average price of $5 per MWh. These sales were required due to a surplus of energy from IPPs and other run of river and must-run resources that collectively required the sales to balance the load.

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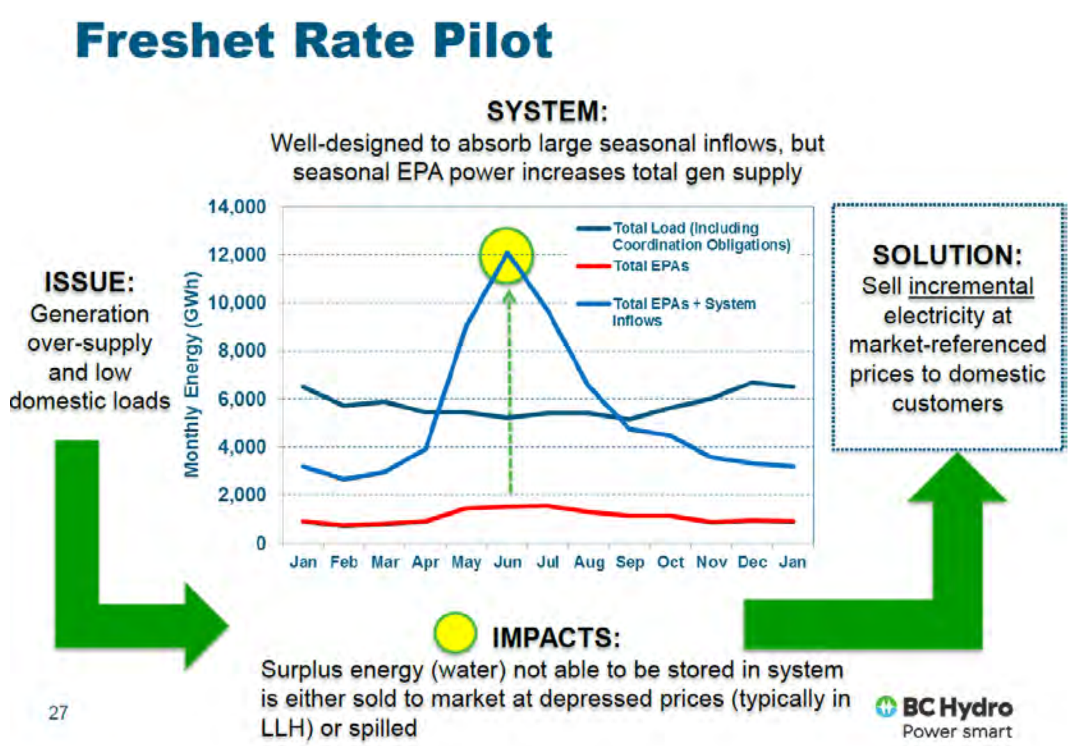

This chart appears to show an exceptionally large amount of surplus energy potentially generated over the months from May to August, some due to an increase in the energy from EPAs, but most of it due to an increase in the energy generated by other must-run resources.

2.38.5 In the interest of clarifying the situation that actually did occur from January, 2016 to March, 2019, please augment the table (and the working Excel model) provided in the response to IR 26.5, so that it shows the breakdown of the monthly system generation between EPA generation, BC Hydro must-run generation, BC Hydro storage dam generation, and BC Hydro other generation, in addition to the monthly values for load, imports and exports as previously requested.

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.26.5.

38.0 Reference: Exhibit B-6, BC Hydro's response to CEABC IR 1.7.2, discussing surplus sales during 2018.

In its response, BC Hydro makes the statement:

"BC Hydro engaged in surplus sales during 2018 (calendar year). Forced surplus sales of 760 GWh were made in May and June 2018, at an average price of $5 per MWh. These sales were required due to a surplus of energy from IPPs and other run of river and must-run resources that collectively required the sales to balance the load.

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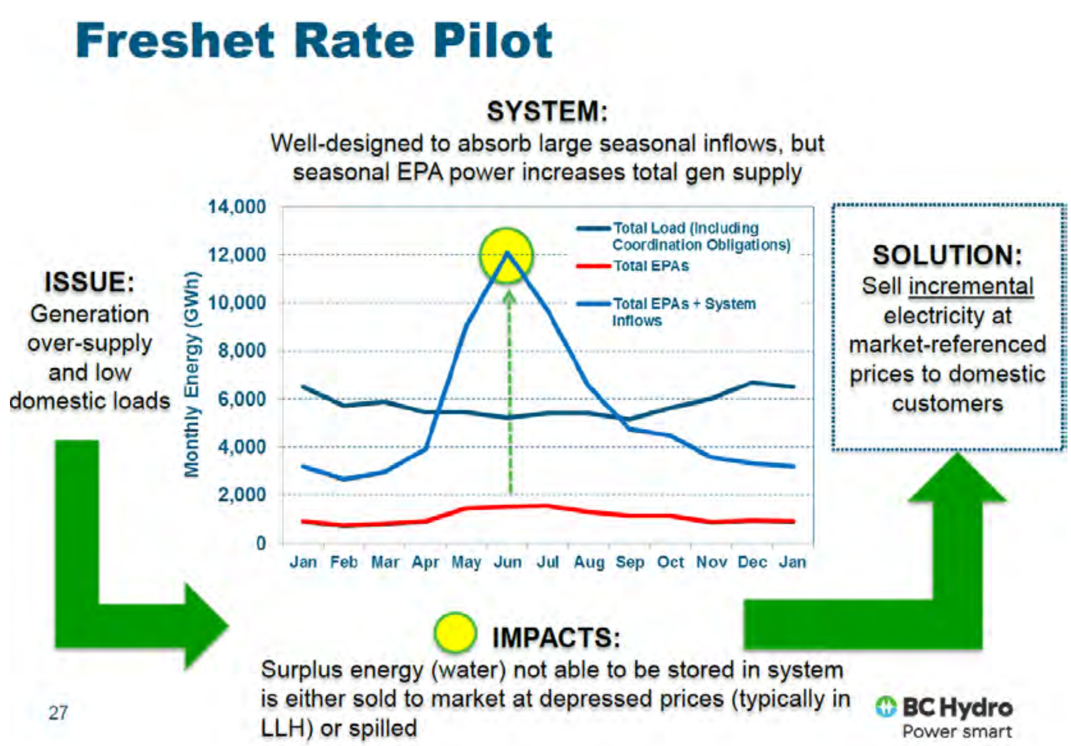

This chart appears to show an exceptionally large amount of surplus energy potentially generated over the months from May to August, some due to an increase in the energy from EPAs, but most of it due to an increase in the energy generated by other must-run resources.

2.38.6 From that Excel model, please produce charts, similar to the "Freshet Rate Pilot" chart above, but representing the actual magnitudes experienced during the period from January 2016 through March, 2019 (i.e. through the calendar years 2016, 2017, and 2018, up to the end of fiscal 2019).

RESPONSE:

The public version of the response to this information request has been redacted to maintain confidentiality over commercially sensitive information. The un-redacted version of the response contains information about BC Hydro's monthly System Inflow information. Publication of the information would enable third parties to model BC Hydro's system to estimate the depth of BC Hydro's energy need and to predict BC Hydro's import and export requirements. The un-redacted version of this response is being made available to the BCUC only.

Please find the requested charts below. BC Hydro clarifies that while the preamble to the question refers to 'surplus energy potentially generated over the months from May to August', this energy is, in the original chart, actually a combination of EPA deliveries and System Inflows. Most of the System Inflow contributes to a seasonal build in System Storage rather than an 'increase in energy generated by other must-run resources' as stated in the preamble.

Please also refer to BC Hydro's response to INCE IR 1.7.5 for a discussion of freshet impacts on combined EPA deliveries and minimum generation requirements.

[redacted]

[redacted]

[redacted]

[redacted]

39.0 Reference: Exhibit B-6, BC Hydro's response to David Ince IR 1.2.4, discussing Greenhouse Gas emissions with respect to imports and exports.

In its response to David Ince IR 1.2.4, BC Hydro states that:

"BC Hydro's production GHG intensity…has ranged from about 0.010 to 0.030 tonnes per MWh in recent years.

… the Western Climate Initiative's most recently published Default Emissions Factor Calculator provides the following default emission factors:

Alberta: 0.522 metric tones/MWh;

Washington: 0.392 metric tones/MWh;

Oregon: 0.587 metric tones/MWh;

California: 0.451 metric tones/MWh."

Further to this enquiry about the GHG emissions from imported electricity, the following discussion took place on May 9, 2019, in the Afternoon Sitting of the Estimates: Ministry of Energy, Mines and Petroleum Resources. The relevant transcript from Hansard is as follows:

A. Weaver: "Can the minister give an estimate of how much emissions were generated based on B.C.'s import of this brown power over the last year? What the emissions input…? That's leakage into our province from emissions, because we're buying brown power in this province."

Hon. M. Mungall: "The Ministry of Environment does work with Powerex to calculate the carbon intensity of the energy that British Columbia imports. I'm happy to get that number for the member."

According to the Minister's response in the Legislature, Powerex, along with the Ministry of Environment, does keep track of the emissions associated with imported electricity. Can BC Hydro, therefore, please solicit the answers to the following questions from Powerex so that this information can be placed in the record of this proceeding:

2.39.1 Do the intensity levels from Alberta, Washington, Oregon, and California (as stated in the quoted IR response), represent the annual average intensities for energy generated within those jurisdictions? Or do they represent the intensity of the exports from those jurisdictions?

RESPONSE:

The Western Climate Initiative (WCI) is the entity responsible for the methodology and best suited to address questions on their Default Emissions Factor Calculator. BC Hydro does not have information on the details behind the methodology. The WCI Archive website includes the WCI Default Factor models and can be accessed at the following link:

http://westernclimateinitiative.org/index.php?option=com_remository&Itemid=37&func=select&id=39

39.0 Reference: Exhibit B-6, BC Hydro's response to David Ince IR 1.2.4, discussing Greenhouse Gas emissions with respect to imports and exports.

In its response to David Ince IR 1.2.4, BC Hydro states that:

"BC Hydro's production GHG intensity…has ranged from about 0.010 to 0.030 tonnes per MWh in recent years.

… the Western Climate Initiative's most recently published Default Emissions Factor Calculator provides the following default emission factors:

Alberta: 0.522 metric tones/MWh;

Washington: 0.392 metric tones/MWh;

Oregon: 0.587 metric tones/MWh;

California: 0.451 metric tones/MWh."

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According to the Minister's response in the Legislature, Powerex, along with the Ministry of Environment, does keep track of the emissions associated with imported electricity. Can BC Hydro, therefore, please solicit the answers to the following questions from Powerex so that this information can be placed in the record of this proceeding:

2.39.2 When Powerex sells energy on the export market, what GHG intensity does it attributed to that energy? Does it give the energy a source-specific intensity, based on the actual known source of the energy (e.g. wind, run-of-river-, storage hydro, etc.)? Or does it simply assign the average intensity of the BC Hydro system generation?

RESPONSE:

The question is requesting information on Powerex's commercial activity in jurisdictions outside of B.C. Details of Powerex's business activities, unless otherwise publicly reported, are commercially sensitive and thus confidential.

The preamble to the CEABC IR 2.39 series of information requests is requesting that BC Hydro solicit information from Powerex to put on the record of this proceeding. BC Hydro declines to seek non-public information from Powerex as disclosing such information could harm Powerex's commercial interests in highly competitive wholesale markets. This in turn would harm BC Hydro ratepayers, since Powerex's net income goes to the benefit of ratepayers.

39.0 Reference: Exhibit B-6, BC Hydro's response to David Ince IR 1.2.4, discussing Greenhouse Gas emissions with respect to imports and exports.

In its response to David Ince IR 1.2.4, BC Hydro states that:

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California: 0.451 metric tones/MWh."

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A. Weaver: "Can the minister give an estimate of how much emissions were generated based on B.C.'s import of this brown power over the last year? What the emissions input…? That's leakage into our province from emissions, because we're buying brown power in this province."

Hon. M. Mungall: "The Ministry of Environment does work with Powerex to calculate the carbon intensity of the energy that British Columbia imports. I'm happy to get that number for the member."

According to the Minister's response in the Legislature, Powerex, along with the Ministry of Environment, does keep track of the emissions associated with imported electricity. Can BC Hydro, therefore, please solicit the answers to the following questions from Powerex so that this information can be placed in the record of this proceeding:

2.39.3 Please provide the amount of energy that has been imported by Powerex from each of those jurisdictions for each of the past 5 years, and the associated GHG emissions as reported by Powerex to the Ministry of Environment. Include both imports to serve domestic load and imports for trade purposes.

RESPONSE:

The volumes associated with imports for both domestic and trade can be located in Attachment 1 to BC Hydro's response to CEABC IR 2.43.1.

The question is requesting information on Powerex's commercial activity in jurisdictions outside of B.C. Details of Powerex's business activities, unless otherwise publicly reported, are commercially sensitive and thus confidential.

GHG emissions are reported to the Ministry of Environment by all electricity importers to the province, and are provided at https://www2.gov.bc.ca/gov/content/environment/climate-change/data/industrial-facility-ghg.

39.0 Reference: Exhibit B-6, BC Hydro's response to David Ince IR 1.2.4, discussing Greenhouse Gas emissions with respect to imports and exports.

In its response to David Ince IR 1.2.4, BC Hydro states that:

"BC Hydro's production GHG intensity…has ranged from about 0.010 to 0.030 tonnes per MWh in recent years.

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A. Weaver: "Can the minister give an estimate of how much emissions were generated based on B.C.'s import of this brown power over the last year? What the emissions input…? That's leakage into our province from emissions, because we're buying brown power in this province."

Hon. M. Mungall: "The Ministry of Environment does work with Powerex to calculate the carbon intensity of the energy that British Columbia imports. I'm happy to get that number for the member."

According to the Minister's response in the Legislature, Powerex, along with the Ministry of Environment, does keep track of the emissions associated with imported electricity. Can BC Hydro, therefore, please solicit the answers to the following questions from Powerex so that this information can be placed in the record of this proceeding:

2.39.4 When Powerex imports energy from those jurisdictions, does it ascertain the specific source of that energy. Does it record the GHG emissions intensity related to that specific source of energy? If so, please answer the previous question in a way that reflects the actual intensities of the known sources of the energy.

RESPONSE:

All electricity importers are required to report in accordance with the Greenhouse Gas Emission Reporting Regulation. Summary information is publicly reported at:

https://www2.gov.bc.ca/gov/content/environment/climate-change/data/industrial-facility-ghg

To the extent that the question requests additional information on Powerex's commercial activity beyond what is publicly disclosed pursuant to the regulation, such as the specific source of imported energy, that information is commercially sensitive and thus confidential.

39.0 Reference: Exhibit B-6, BC Hydro's response to David Ince IR 1.2.4, discussing Greenhouse Gas emissions with respect to imports and exports.

In its response to David Ince IR 1.2.4, BC Hydro states that:

"BC Hydro's production GHG intensity…has ranged from about 0.010 to 0.030 tonnes per MWh in recent years.

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Hon. M. Mungall: "The Ministry of Environment does work with Powerex to calculate the carbon intensity of the energy that British Columbia imports. I'm happy to get that number for the member."

According to the Minister's response in the Legislature, Powerex, along with the Ministry of Environment, does keep track of the emissions associated with imported electricity. Can BC Hydro, therefore, please solicit the answers to the following questions from Powerex so that this information can be placed in the record of this proceeding:

2.39.5 Please confirm that any energy that is imported into BC by Powerex is instantaneously consumed by BC Hydro's customers, whether it is imported for domestic or trade purposes.

RESPONSE:

Not confirmed.

40.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.9.3, and Exhibit B-1, the Application, Appendix O, Load Forecast Report, specifically Shale gas and Other large oil and gas operations.

BC Hydro's response to CEABC IR 1.9.3 includes the statement:

"As for deep cut plants, BC Hydro does not include an intensity factor for these types of operations. Deep cut plants are included in the Other Large Oil and Gas segments load forecast (i.e., the gas processor sub-segment) where the loadforecast methodology used does not use electrical intensity factors."

Section 7.5.2.2.1 of Appendix O, on Other large oil and gas operations description, includes the statements:

"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." And…

"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."

Table 7-16 of BC Hydro's F2020- 2021 RRA, on Other Large Oil and Gas Operations Segment Mid, High and Low Forecast Before Rate Impacts, shows:

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.

2.40.1 Please provide a table, similar in format to Table 7-16, that breaks out, over the 5 years from F2019 to F2024, the Mid, High and Low forecast energy requirements for:

- Conventional gas processing plants
- Deep-cut gas processing plants, and
- Natural gas pipelines (i.e. using electric compression)

RESPONSE:

Given the small number of accounts that make up some of these sub-segments, as well as the LNG projects making up the other sub-segment included in the other large oil and gas operations, the requested information could be used to deduce the probability weightings BC Hydro has assigned to specific accounts across the low, mid and high forecast.

The information on the specific timing and probability weighting applied to these loads is commercially sensitive because BC Hydro's assessment is based on commercial information provided by the customer in confidence. BC Hydro must respect this confidence so that we can obtain accurate information for future load

forecasts. This remains the case even if individual loads are aggregated due to the relatively small number of customers in each of these sub-segments.

As such, we respectfully decline to make the requested information available to Interveners. If the BCUC believes that the information would be useful, we can provide the information confidentially to the BCUC only. General information about BC Hydro's probability weighting can be found on pages 3-24 to 3-27 of Chapter 3 of the Application.

40.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.9.3, and Exhibit B-1, the Application, Appendix O, Load Forecast Report, specifically Shale gas and Other large oil and gas operations.

BC Hydro's response to CEABC IR 1.9.3 includes the statement:

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"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." And…

"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."

Table 7-16 of BC Hydro's F2020- 2021 RRA, on Other Large Oil and Gas Operations Segment Mid, High and Low Forecast Before Rate Impacts, shows:

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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.

2.40.2 By the year F2024, what is BC Hydro's estimate of the total work energy that will be consumed in each of these sub-segments, and what proportion of that energy is represented by BC Hydro's projected electricity deliveries? If the balance of the work energy is all supplied by fossil fuels, what CO2e emissions would that produce in F2024?

RESPONSE:

BC Hydro's load forecast for these sub-segments is largely based on customer load requests and does not use or estimate total work energy requirements. Therefore, we do not have an estimate of the proportion of the total work energy that is not served by BC Hydro. However, the aggregate total work energy supplied by fossil fuels is likely to be significantly higher than the aggregate energy supplied by electricity, recognizing the relative proportion can differ across the various sub-segments and even across facilities within a sub-segment (e.g., LNG terminals that plan to use natural gas to drive their compression requirements versus LNG terminals that plan to use electricity).

BC Hydro does not have an estimate of CO2e emissions for each of the sub-segments. However, we are supporting Phase 2 of the Government of B.C.'s Comprehensive Review of BC Hydro which includes identifying additional opportunities to reduce greenhouse gas emissions through fuel-switching, electrification, energy efficiency and conservation. These opportunities will be reflected in future load forecast updates when they become more certain.

41.0 Reference: Exhibit B-6, BC Hydro response to Ince IR 1.6.4, Appendix J, Attachment 1. Capital Projects (PRES), Service Percentages

BC Hydro's response to Ince IR 1.6.4c) stated;

"(c) BC Hydro's expected service percentages for total energy requirements for the upstream gas production and processor loads by transmission planning areas are provided in the following table."

Dawson Creek	**50% ramping up to 54%, then down to 53% over the forecast period.**
Groundbirch	**45% over the forecast period.**
Chetwynd	**0% over the forecast period.**
Fox / Fort St. John	**0% over the forecast period.**
G.M. Shrum	**0% ramping up to 7% over the forecast period.**

BC Hydro's Electric Load Forecast F2013 to 2033 ("2012 Forecast"), located at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/2012-electric-load-forecast-report.pdf

at the bottom of page 93, states:

"The service percent is the proportion of total energy to be provided by BC Hydro's electricity service. … For the Montney, the forecast is divided into five areas with the following service percentages."

- Dawson Creek: 40% ramping up to 85% over the forecast horizon
- Groundbirch: 30% ramping up to 95%
- Chetwynd: 40% ramping up to 85%
- Fox/Fort St. John: 5% ramping up to 70%
- G.M. Shrum: 15% ramping up to 25%.

Subsequent BC Hydro Load Forecasts, after the 2012 Forecast, did not provide information on service percentages.

2.41.1 What are the current service percentages for the Dawson Creek and Groundbirch areas? Please confirm that the current service percentages for Chetwynd, Fox/Fort St. John and GM Shrum are 0 per cent (per the first table above) or provide the amounts.

RESPONSE:

The information provided below also responds to the entire CEABC IR 2.41 series.

This IR series asks BC Hydro to explain the lower service percentage forecast of shale gas production and processing in each of the five Montney shale basin areas served by BC Hydro in the October 2018 Load Forecast compared to the December 2012 Load Forecast.

BC Hydro notes that the December 2012 Load Forecast was produced six years ago and is therefore out-dated. Consequently any direct comparison between this forecast and the October 2018 Load Forecast beyond fiscal 2024 is not meaningful. BC Hydro will be filing an updated 20-year load forecast as part of this proceeding on October 3, 2019.

The main reason for the lower service percentage forecast in the October 2018 Load Forecast versus the December 2012 Load Forecast, over a similar forecast period (fiscal 2019 to fiscal 2024), is lower forecast natural gas prices, which favour the use of natural gas over electricity to provide gas production and processing work energy requirements. Natural gas prices have declined relative to what was assumed in the December 2012 Load Forecast. For example, in 2012, natural gas prices were forecast to be $4.15/MMBtu in 2018. Since that time, natural gas prices have fallen by two-thirds. From January 1, 2018 to October 31, 2018, natural gas prices averaged $1.50/MMBtu. This decline impacts the relative competitiveness of electricity versus natural gas to provide work energy requirements. Generally, this reduces the likelihood that new producers and processors will choose electricity supply from BC Hydro relative to what was assumed in the December 2012 Load Forecast.

However, notwithstanding the reduction in service percentages, the total expected electrical load in fiscal 2024 between the two forecasts is similar (443 MW in the 2012 forecast compared to 390 MW in the 2018 forecast). This is due to the fact that the liquids-rich Dawson Creek area is experiencing greater than anticipated development and therefore, higher shale gas production volumes relative to what was forecast in the December 2012 Load Forecast.

Service percentages are calculated by dividing the production forecast that is expected to be served by BC Hydro, by the total shale gas production forecast. The following changes have impacted the electricity percentage forecasts across the five Montney areas relative to the December 2012 Load Forecast:

- **Production cost expectations across the Montney shale basin since the December 2012 Load Forecast. This information, combined with new information on the overall geology of the basin, has influenced the basin's development in ways that were not known when the 2012 forecast was**

developed. Areas where service percentages were particularly negatively affected are Chetwynd, Fox/Fort St. John and G.M. Shrum;

- **The increased attractiveness of producing natural gas liquids, relative to what was assumed in the 2012 forecast. This change helps lift the natural gas production forecasts as producers targeting natural gas liquids also produce associated natural gas. Service percentages still decline in affected areas (Dawson Creek and G.M. Shrum), because of the predominant impact of lower natural gas prices. However, the decline is proportionally less than in non-liquids producing areas;**
- **B.C. LNG project developments and their direct relationships with upstream producers have changed relative to the assumptions reflected in the 2012 forecast. These developments also change the shale gas production forecasts within affected areas in the Montney region; and**
- **There have been a number of land use management developments and project-specific changes that have influenced both gas production forecasts and electricity service projections in specific areas.**

To more easily compare the differences between the forecasts, Table 1 below provides a comparison of the December 2012 Load Forecast and the October 2018 Load Forecast for each of the Montney areas for the following information:

- **Forecast service percentage by BC Hydro;**
- **Forecast total shale gas production in MMcf/day;**
- **Forecast proportion of shale gas production serviced by BC Hydro in MMcf/day; and**
- **Forecast and actual BC Hydro serviced load in MW.**

Table 1: Montney shale gas production and electrical load services percentages - December 2012 and October 2018 Load Forecasts

December 2012 Load Forecast

1) Service Percentage by BC Hydro

Fiscal Yr	Dawson	Grdbirch	Chetwynd	Fox/FSJ	G.M.S.
2013	40%	30%	40%	5%	15%
2014	40%	30%	40%	35%	15%
2015	80%	50%	50%	45%	25%
2016	85%	95%	60%	60%	25%
2017	85%	95%	70%	70%	25%
2018	85%	95%	80%	70%	25%
2019	85%	95%	85%	70%	25%
2020	85%	95%	85%	70%	25%
2021	85%	95%	85%	70%	25%
2022	85%	95%	85%	70%	25%
2023	85%	95%	85%	70%	25%
2024	85%	95%	85%	70%	25%

2) Montney Shale Gas Production (MMcf/day)

Fiscal Yr	Dawson	Grdbirch	Chetwynd	Fox/FSJ	G.M.S.	Total
2013	696	197	12	14	464	1,383
2014	820	234	15	16	563	1,648
2015	1,144	345	24	23	762	2,298
2016	1,422	433	34	43	956	2,889
2017	1,635	504	45	67	1,110	3,362
2018	1,722	652	58	94	1,244	3,770
2019	1,900	778	72	125	1,277	4,151
2020	1,872	992	85	155	1,331	4,436
2021	1,893	1,035	96	181	1,328	4,533
2022	1,898	1,114	107	209	1,314	4,642
2023	1,917	1,140	119	237	1,336	4,749
2024	1,913	1,163	130	267	1,373	4,846
2025	1,871	1,164	140	291	1,383	4,849
2026	1,830	1,165	149	315	1,394	4,854
2027	1,815	1,155	160	342	1,412	4,884
2028	1,802	1,146	170	369	1,433	4,920
2029	1,799	1,126	181	396	1,452	4,954
2030	1,787	1,099	191	422	1,465	4,964
2031	1,772	1,071	201	447	1,475	4,965
2032	1,748	1,040	210	471	1,487	4,955
2033	1,717	1,006	216	493	1,499	4,931

3) BC Hydro Served Production (MMcf/day)

Fiscal Yr	Dawson	Grdbirch	Chetwynd	Fox/FSJ	G.M.S.	Total
2018	1,464	619	46	66	311	2,506
2019	1,615	739	61	87	319	2,821
2024	1,626	1,105	111	187	343	3,373

4) BC Hydro Served Load (MW)

Fiscal Yr	Dawson	Grdbirch	Chetwynd	Fox/FSJ	G.M.S.	Total
2018	205	74	5	6	30	320
2019	209	101	7	9	34	360
2024	222	149	13	22	36	443

October 2018 Load Forecast

1) Service Percentage by BC Hydro — Correction

Fiscal Yr	Dawson	Grdbirch	Chetwynd	Fox/FSJ	G.M.S.
2013					
2014					
2015					
2016					
2017					
2018 *	49%	49%	0%	6%	0%
2019	50%	45%	0%	4%	0%
2020	54%	45%	0%	6%	0%
2021	51%	45%	0%	8%	2%
2022	51%	45%	0%	10%	4%
2023	53%	45%	0%	10%	7%
2024	53%	45%	0%	10%	7%

* Estimate based on tables 2 & 3 below.

2) Montney Shale Gas Production (MMcf/day)

Fiscal Yr	Dawson	Grdbirch	Chetwynd	Fox/FSJ	G.M.S.	Total
2013 *	622	395	0	35	476	1,528
2014 *	761	233	0	35	837	1,866
2015 *	1,051	230	0	47	1,003	2,330
2016 *	1,381	339	0	62	1,070	2,852
2017 *	1,773	353	0	88	1,123	3,338
2018 *	2,108	370	0	108	1,125	3,711
2019	2,659	387	0	151	1,123	4,320
2020	2,591	539	0	158	1,155	4,443
2021	2,652	546	0	161	1,180	4,540
2022	2,674	627	0	174	1,221	4,695
2023	3,140	782	0	201	1,449	5,572
2024	3,521	1,019	0	248	1,921	6,710

* Estimate of actual production based on wells drilled in areas.

3) BC Hydro Served Production (MMcf/day)

Fiscal Yr	Dawson	Grdbirch	Chetwynd	Fox/FSJ	G.M.S.	Total
2018 *	1,026	181	0	6	0	1,213
2019	1,329	174	0	6	0	1,510
2024	1,866	459	0	25	134	2,484

* Estimate of actual production based on wells drilled in areas.

4) BC Hydro Served Load (MW)

Fiscal Yr	Dawson	Grdbirch	Chetwynd	Fox/FSJ	G.M.S.	Total
2018 *	144	33	0	2	0	178
2019	205	29	0	2	0	235
2024	315	53	0	3	19	390

* Estimate of Fox/FSJ - many small distribution served accounts

Table 1 also includes the October 2018 Load Forecast period from fiscal 2019 to fiscal 2024, as well as the estimated actual shale gas production total and BC Hydro supplied production for fiscal 2018.

BC Hydro wishes to correct the information provided in BC Hydro's response to INCE IR 1.6.4. Specifically, the forecast electrification percentage in the Fox/Fort St. John area should be 4 per cent increasing to 10 per cent over the forecast period. This minor correction is highlighted in Table 1 above.

Based on fiscal 2018 estimated actuals, the current service percentages for both the Dawson Creek and Groundbirch areas are 49 per cent. In fiscal 2019 these percentages are expected increase to 50 per cent in the Dawson Creek area and decrease to 45 per cent in the Groundbirch area. BC Hydro confirms the current service percentages for the Chetwynd and G.M. Shrum areas are 0 per cent. The current service percentage for Fox/Fort St. John is 6 per cent, as per the correction highlighted in Table 1 above. BC Hydro clarifies that its service percentage forecasts apply to the shale gas segment only. Conventional gas production in these areas serviced by BC Hydro is not included in the forecast calculation.

Table 2 below summarizes key information from Table 1, provides the two inputs used to calculate the forecast service percentage in fiscal 2024 (serviced gas production/total gas production x 100) and provides the main reasons for the differences in the two inputs between the 2012 forecast and the 2018 forecast. Table 2 also references the corresponding CEABC IRs which requested the information.

Table 2: Service Percentage Calculations , Changes since 2012, and IR references

Key Assumptions by Montney Area	Load Forecast Dec 2012	Load Forecast Oct 2018	Changes since 2012 forecast	CEABC IR
Dawson Creek				2.41.2.3
2019 - Service Percentage (%)	85	50	Revised starting percentages are based on updated actual information and forecasts	
2024 - Forecast inputs:				
(a) Gas Production (MMcf/day)	1,913	3,521	Natural gas liquids and gas for LNG export favours increased gas production	
(b) Served Production (MMcf/day)	1,626	1,866	Lower gas prices favour self-supply over BC Hydro service	
Service Percentage (%) = b/a x 100	85	53	Increase in current service enabled by DCAT	
Serviced Load (MW)	222	315		2.41.2.2
Groundbirch				2.41.2.3
2019 - Service Percentage (%)	95	45	Revised starting percentages are based on updated actual information and forecasts	
2024 - Forecast inputs:				
(a) Gas Production (MMcf/day)	1,163	1,049	Similar forecasts	
(b) Served Production (MMcf/day)	1,105	472	Lower gas prices and relatively dry gas favour self-supply over electricity supply	
Service Percentage (%) = b/a x 100	95	45		
Serviced Load (MW)	149	53		2.41.2.2
Chetwynd				2.41.2.4
2019 - Service Percentage (%)	85	0	Revised starting percentages are based on updated actual information and forecasts. BC Hydro currently serves negligible load	
2024 - Forecast inputs:				
(a) Gas Production (MMcf/day)	130	0	Gas production is no longer expected to occur because gas is dry and land use changes preclude a significant portion from oil and gas development	
(b) Served Production (MMcf/day)	111	0	Gas production is no longer expected	
Service Percentage (%) = b/a x 100	85	0		
Serviced Load (MW)	13	0		
Fox/Fort St. John				2.41.2.4
2019 - Service Percentage (%)	70	4	Revised starting percentages are based on updated actual information and forecasts. BC Hydro currently serves only 2 MW	
2024 - Forecast inputs:	95	10		
(a) Gas Production (MMcf/day)	267	248	Similar forecasts	
(b) Served Production (MMcf/day)	187	25	Lower gas prices favour self-supply over electricity supply	
Service Percentage (%) = b/a x 100	70	10		
Serviced Load (MW)	22	3		
G.M. Shrum				2.41.2.5
2019 - Service Percentage (%)	25	0	Revised starting percentages are based on updated actual information and forecasts. BC Hydro currently serves negligible load	
2024 - Forecast inputs:	25	7		
(a) Gas Production (MMcf/day)	1,373	1,921	Natural gas liquids and gas for LNG export favours increased gas production	
(b) Served Production (MMcf/day)	343	134	Lower gas price favours self-supply over electricity supply	
Service Percentage (%) = b/a x 100	25	7		
Serviced Load (MW)	36	19		

The following information addresses a number of specific IRs in the CEABC IR 2.41 series.

CEABC IR 2.41.2.2 asks BC Hydro to explain why the service percentages in the Dawson Creek and Groundbirch areas have declined even though those areas contain the new PRES transmission line.

In response, while the service percentages have decreased, the actual load served has not. From Table 2 the expected combined Dawson/Grounbirch load served by BC Hydro in fiscal 2024 is 371 MW in the 2012 forecast and 368 MW in the 2018 load forecast. The reason for the reduced service percentage is an expected increase in the Dawson Creek area shale gas production relative to the production amount expected to be served by BC Hydro. BC Hydro wishes to correct an underlying premise in CEABC IR 2.41.2.2, with respect to the PRES transmission line. The planned PRES transmission line is not yet in service. The transmission line that enabled past load growth in the Dawson Creek and Groundbirch areas is the Dawson Creek to Chetwynd Area Transmission (DCAT) line which went into service in 2015. One of the benefits of the PRES project is that it will support future growth in these areas.

CEABC IR 2.41.2.6 asks why the forecast service percentage for the G.M. Shrum area is greater than the forecast service percentage for the Chetwynd and Fox/Fort St. John areas. The IR further asks if the differences are due to expectation of transmission lines being extended to the G.M. Shrum area but not in the Chetwynd or Fox/Fort St. John areas.

BC Hydro has been studying various transmission options for supplying the G.M. Shrum area for a number of years, based on producer interest in taking BC Hydro service. The North Montney – Transmission Development project would provide transmission facilities in the area, and this project will proceed once there are formal commitments from potential customers. For further information on this project please refer to BC Hydro's response to BCUC IR 2.254.2.

However, as discussed above, the declines in natural gas prices have generally favoured self-supply over electricity supply relative to when the 2012 load forecast was developed. The basis for the forecast electrification in the G.M. Shrum area is a probabilistic assessment of producers who are considering BC Hydro service. In contrast, no producer in the Chetwynd area has expressed interest in taking BC Hydro service and only very limited interest has been expressed in the Fox/Fort St. John area. Thus, the October 2018 Load Forecast expects no material producer load within the forecast period, and therefore BC Hydro is currently not undertaking planning studies to extend transmission service into those areas.

In general, transmission line assumptions impact the load forecast only insofar as expected in-service dates for new lines may affect when new customers can receive service. Otherwise, BC Hydro's load forecast process assumes that

electricity service will be provided to any customers requesting it, provided they meet the terms and condition of BC Hydro's tariffs.

CEABC IRs 2.41.3, 2.41.3.1, 2.41.3.2, 2.41.3.3, 2.41.3.4, 2.41.3.5 ask BC Hydro to explain how the service percentages by 2033 in the 2012 Load Forecast can be achieved in each of the areas, given the forecast lower service percentages for fiscal 2024 in the 2018 Load Forecast.

As noted above, any direct comparison between the December 2012 Load Forecast and the October 2018 Load Forecast beyond fiscal 2024 (i.e., fiscal 2025 to fiscal 2033) is not meaningful.

BC Hydro's shale gas segment forecasts are based on BC Hydro's probability-weighted assessment of the likelihood that production and processing plants will materialize, as well as the likelihood that those plants will take electricity service from BC Hydro rather than self-supply their work energy requirements. While our mid forecast projects load growth in the segment, we are also projecting many plants will prefer to self-supply for the reasons stated above.

The October 2018 high forecast, which assumes higher levels of electrification as well as higher gas production levels, provides an indication of how much additional load may occur. These estimates are provided in Table 7-14 of Appendix O of the Application. However, even the high forecast likely does not capture the full electrification potential in the shale gas segment. As stated in BC Hydro's response to CEABC IR 2.40.2, we are supporting Phase 2 of the Government of B.C.'s Comprehensive Review of BC Hydro which includes identifying additional opportunities to reduce greenhouse gas emissions through fuel-switching, electrification, energy efficiency and conservation. To the extent these opportunities are identified in the shale gas segment, they will be reflected in future load forecast updates when they become more certain.

41.0 Reference: Exhibit B-6, BC Hydro response to Ince IR 1.6.4, Appendix J, Attachment 1. Capital Projects (PRES), Service Percentages

BC Hydro's response to Ince IR 1.6.4c) stated;

"(c) BC Hydro's expected service percentages for total energy requirements for the upstream gas production and processor loads by transmission planning areas are provided in the following table."

Dawson Creek	**50% ramping up to 54%, then down to 53% over the forecast period.**
Groundbirch	**45% over the forecast period.**
Chetwynd	**0% over the forecast period.**
Fox / Fort St. John	**0% over the forecast period.**
G.M. Shrum	**0% ramping up to 7% over the forecast period.**

BC Hydro's Electric Load Forecast F2013 to 2033 ("2012 Forecast"), located at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/2012-electric-load-forecast-report.pdf

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- Groundbirch: 30% ramping up to 95%
- Chetwynd: 40% ramping up to 85%
- Fox/Fort St. John: 5% ramping up to 70%
- G.M. Shrum: 15% ramping up to 25%.

Subsequent BC Hydro Load Forecasts, after the 2012 Forecast, did not provide information on service percentages.

2.41.2 If the "forecast period" in BC Hydro's response to Ince IR 1.6.4 is 20 years, then please explain why BC Hydro's forecast of the proportion of total energy to be provided by electricity service has decreased so substantially since 2012? (The 2012 Forecast had a

"forecast horizon" of 20 years). Please include the following explanations:

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.41.1.

41.0 Reference: Exhibit B-6, BC Hydro response to Ince IR 1.6.4, Appendix J, Attachment 1. Capital Projects (PRES), Service Percentages

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Subsequent BC Hydro Load Forecasts, after the 2012 Forecast, did not provide information on service percentages.

2.41.2 If the "forecast period" in BC Hydro's response to Ince IR 1.6.4 is 20 years, then please explain why BC Hydro's forecast of the proportion of total energy to be provided by electricity service has decreased so substantially since 2012? (The 2012 Forecast had a

"forecast horizon" of 20 years). Please include the following explanations:

2.41.2.1 Why has BC Hydro decreased the upper end service percentage levels for all areas so substantially (i.e. an average decrease of over 71% across all areas)?

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.41.1.

41.0 Reference: Exhibit B-6, BC Hydro response to Ince IR 1.6.4, Appendix J, Attachment 1. Capital Projects (PRES), Service Percentages

BC Hydro's response to Ince IR 1.6.4c) stated;

"(c) BC Hydro's expected service percentages for total energy requirements for the upstream gas production and processor loads by transmission planning areas are provided in the following table."

Dawson Creek	**50% ramping up to 54%, then down to 53% over the forecast period.**
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Subsequent BC Hydro Load Forecasts, after the 2012 Forecast, did not provide information on service percentages.

2.41.2 If the "forecast period" in BC Hydro's response to Ince IR 1.6.4 is 20 years, then please explain why BC Hydro's forecast of the proportion of total energy to be provided by electricity service has decreased so substantially since 2012? (The 2012 Forecast had a

"forecast horizon" of 20 years). Please include the following explanations:

2.41.2.2 For the Dawson Creek and Groundbirch areas, that contain the new PRES transmission line, why has BC Hydro decreased the upper end of service provision levels from 85% and 95% to 53% and 45%, respectively?

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.41.1.

41.0 Reference: Exhibit B-6, BC Hydro response to Ince IR 1.6.4, Appendix J, Attachment 1. Capital Projects (PRES), Service Percentages

BC Hydro's response to Ince IR 1.6.4c) stated;

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Dawson Creek	**50% ramping up to 54%, then down to 53% over the forecast period.**
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- Chetwynd: 40% ramping up to 85%
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- G.M. Shrum: 15% ramping up to 25%.

Subsequent BC Hydro Load Forecasts, after the 2012 Forecast, did not provide information on service percentages.

2.41.2 If the "forecast period" in BC Hydro's response to Ince IR 1.6.4 is 20 years, then please explain why BC Hydro's forecast of the proportion of total energy to be provided by electricity service has decreased so substantially since 2012? (The 2012 Forecast had a

"forecast horizon" of 20 years). Please include the following explanations:

2.41.2.3 For the Dawson Creek and Groundbirch areas, that contain the new PRES transmission line, why has BC Hydro increased the starting levels of service provision from 40% and 30% to 50% and 45%, respectively?

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.41.1.

41.0 Reference: Exhibit B-6, BC Hydro response to Ince IR 1.6.4, Appendix J, Attachment 1. Capital Projects (PRES), Service Percentages

BC Hydro's response to Ince IR 1.6.4c) stated;

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Dawson Creek	**50% ramping up to 54%, then down to 53% over the forecast period.**
Groundbirch	**45% over the forecast period.**
Chetwynd	**0% over the forecast period.**
Fox / Fort St. John	**0% over the forecast period.**
G.M. Shrum	**0% ramping up to 7% over the forecast period.**

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- G.M. Shrum: 15% ramping up to 25%.

Subsequent BC Hydro Load Forecasts, after the 2012 Forecast, did not provide information on service percentages.

2.41.2 If the "forecast period" in BC Hydro's response to Ince IR 1.6.4 is 20 years, then please explain why BC Hydro's forecast of the proportion of total energy to be provided by electricity service has decreased so substantially since 2012? (The 2012 Forecast had a

"forecast horizon" of 20 years). Please include the following explanations:

2.41.2.4 For the Chetwynd and Fox/Fort St. John areas, why does BC Hydro now forecast 0% service, after forecasting as much as 70% and 85% service in 2012, respectively?

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.41.1.

41.0 Reference: Exhibit B-6, BC Hydro response to Ince IR 1.6.4, Appendix J, Attachment 1. Capital Projects (PRES), Service Percentages

BC Hydro's response to Ince IR 1.6.4c) stated;

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Dawson Creek	**50% ramping up to 54%, then down to 53% over the forecast period.**
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- Fox/Fort St. John: 5% ramping up to 70%
- G.M. Shrum: 15% ramping up to 25%.

Subsequent BC Hydro Load Forecasts, after the 2012 Forecast, did not provide information on service percentages.

2.41.2 If the "forecast period" in BC Hydro's response to Ince IR 1.6.4 is 20 years, then please explain why BC Hydro's forecast of the proportion of total energy to be provided by electricity service has decreased so substantially since 2012? (The 2012 Forecast had a

"forecast horizon" of 20 years). Please include the following explanations:

2.41.2.5 For the GM Shrum area, why does BC Hydro now forecast 0% to 7% service, after forecasting 20% to 40% service in 2012?

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.41.1.

41.0 Reference: Exhibit B-6, BC Hydro response to Ince IR 1.6.4, Appendix J, Attachment 1. Capital Projects (PRES), Service Percentages

BC Hydro's response to Ince IR 1.6.4c) stated;

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Subsequent BC Hydro Load Forecasts, after the 2012 Forecast, did not provide information on service percentages.

2.41.2 If the "forecast period" in BC Hydro's response to Ince IR 1.6.4 is 20 years, then please explain why BC Hydro's forecast of the proportion of total energy to be provided by electricity service has decreased so substantially since 2012? (The 2012 Forecast had a

"forecast horizon" of 20 years). Please include the following explanations:

2.41.2.6 Why does BC Hydro forecast at least 7% service for the GM Shrum area whereas it forecast no more than 0% for the Chetwynd and Fox/Fort St. John areas? Does BC Hydro expect transmission lines will be extended in the GM Shrum area but not the Chetwynd or Fox/Fort St. John areas?

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.41.1.

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- G.M. Shrum: 15% ramping up to 25%.

Subsequent BC Hydro Load Forecasts, after the 2012 Forecast, did not provide information on service percentages.

2.41.3 If the "forecast period" in BC Hydro's response to Ince IR 1.6.4 ends in F2024, then please explain how the large service percentages in the 2012 Forecast (that are based on a "forecast horizon" ending in F2033) can be reached, in the remaining 10

years, from the small service percentages expected in F2024? Please include the following explanations:

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.41.1.

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years, from the small service percentages expected in F2024? Please include the following explanations:

2.41.3.1 For the Dawson Creek area, how will BC Hydro raise the service percentage from 54% in F2024to 85% in F2033?

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.41.1.

41.0 Reference: Exhibit B-6, BC Hydro response to Ince IR 1.6.4, Appendix J, Attachment 1. Capital Projects (PRES), Service Percentages

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2.41.3 If the "forecast period" in BC Hydro's response to Ince IR 1.6.4 ends in F2024, then please explain how the large service percentages in the 2012 Forecast (that are based on a "forecast horizon" ending in F2033) can be reached, in the remaining 10

years, from the small service percentages expected in F2024? Please include the following explanations:

2.41.3.2 For the Groundbirch Creek area, how will BC Hydro more than double the service percentage from 45%in F2024 to 95% in F2033?

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.41.1.

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years, from the small service percentages expected in F2024? Please include the following explanations:

2.41.3.3 For the Chetwynd area, how will BC Hydro raise the service percentage from 0% in F2024 to 85% in F2033?

RESPONSE:

Please refer to BC Hydro’s response to CEABC IR 2.41.1.

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Groundbirch	**45% over the forecast period.**
Chetwynd	**0% over the forecast period.**
Fox / Fort St. John	**0% over the forecast period.**
G.M. Shrum	**0% ramping up to 7% over the forecast period.**

BC Hydro's Electric Load Forecast F2013 to 2033 ("2012 Forecast"), located at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/2012-electric-load-forecast-report.pdf

at the bottom of page 93, states:

"The service percent is the proportion of total energy to be provided by BC Hydro's electricity service. … For the Montney, the forecast is divided into five areas with the following service percentages."

- Dawson Creek: 40% ramping up to 85% over the forecast horizon
- Groundbirch: 30% ramping up to 95%
- Chetwynd: 40% ramping up to 85%
- Fox/Fort St. John: 5% ramping up to 70%
- G.M. Shrum: 15% ramping up to 25%.

Subsequent BC Hydro Load Forecasts, after the 2012 Forecast, did not provide information on service percentages.

2.41.3 If the "forecast period" in BC Hydro's response to Ince IR 1.6.4 ends in F2024, then please explain how the large service percentages in the 2012 Forecast (that are based on a "forecast horizon" ending in F2033) can be reached, in the remaining 10

years, from the small service percentages expected in F2024? Please include the following explanations:

2.41.3.4 For the Fox/Fort St.John area, how will BC Hydro raise the service percentage from 0% in F2024 to 70% in F2033?

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.41.1.

41.0 Reference: Exhibit B-6, BC Hydro response to Ince IR 1.6.4, Appendix J, Attachment 1. Capital Projects (PRES), Service Percentages

BC Hydro's response to Ince IR 1.6.4c) stated;

"(c) BC Hydro's expected service percentages for total energy requirements for the upstream gas production and processor loads by transmission planning areas are provided in the following table."

Dawson Creek	**50% ramping up to 54%, then down to 53% over the forecast period.**
Groundbirch	**45% over the forecast period.**
Chetwynd	**0% over the forecast period.**
Fox / Fort St. John	**0% over the forecast period.**
G.M. Shrum	**0% ramping up to 7% over the forecast period.**

BC Hydro's Electric Load Forecast F2013 to 2033 ("2012 Forecast"), located at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/2012-electric-load-forecast-report.pdf

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- G.M. Shrum: 15% ramping up to 25%.

Subsequent BC Hydro Load Forecasts, after the 2012 Forecast, did not provide information on service percentages.

2.41.3 If the "forecast period" in BC Hydro's response to Ince IR 1.6.4 ends in F2024, then please explain how the large service percentages in the 2012 Forecast (that are based on a "forecast horizon" ending in F2033) can be reached, in the remaining 10

years, from the small service percentages expected in F2024? Please include the following explanations:

2.41.3.5 For the GM Shrum area, how will BC Hydro raise the service percentage from 7% in F2024to 25% in F2033?

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.41.1.

41.0 Reference: Exhibit B-6, BC Hydro response to Ince IR 1.6.4, Appendix J, Attachment 1. Capital Projects (PRES), Service Percentages

BC Hydro's response to Ince IR 1.6.4c) stated;

"(c) BC Hydro's expected service percentages for total energy requirements for the upstream gas production and processor loads by transmission planning areas are provided in the following table."

Dawson Creek	**50% ramping up to 54%, then down to 53% over the forecast period.**
Groundbirch	**45% over the forecast period.**
Chetwynd	**0% over the forecast period.**
Fox / Fort St. John	**0% over the forecast period.**
G.M. Shrum	**0% ramping up to 7% over the forecast period.**

BC Hydro's Electric Load Forecast F2013 to 2033 ("2012 Forecast"), located at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/2012-electric-load-forecast-report.pdf

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- Groundbirch: 30% ramping up to 95%
- Chetwynd: 40% ramping up to 85%
- Fox/Fort St. John: 5% ramping up to 70%
- G.M. Shrum: 15% ramping up to 25%.

Subsequent BC Hydro Load Forecasts, after the 2012 Forecast, did not provide information on service percentages.

2.41.4 For the GM Shrum area, if the "forecast period" in BC Hydro's response to Ince IR 1.6.4 ends in F2024, how will BC Hydro reach a 7% service percentage in 5 years? Is BC Hydro expecting transmission lines will be extended in the GM Shrum area?

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.41.1.

41.0 Reference: Exhibit B-6, BC Hydro response to Ince IR 1.6.4, Appendix J, Attachment 1. Capital Projects (PRES), Service Percentages

BC Hydro's response to Ince IR 1.6.4c) stated;

"(c) BC Hydro's expected service percentages for total energy requirements for the upstream gas production and processor loads by transmission planning areas are provided in the following table."

Dawson Creek	**50% ramping up to 54%, then down to 53% over the forecast period.**
Groundbirch	**45% over the forecast period.**
Chetwynd	**0% over the forecast period.**
Fox / Fort St. John	**0% over the forecast period.**
G.M. Shrum	**0% ramping up to 7% over the forecast period.**

BC Hydro's Electric Load Forecast F2013 to 2033 ("2012 Forecast"), located at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/2012-electric-load-forecast-report.pdf

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- Chetwynd: 40% ramping up to 85%
- Fox/Fort St. John: 5% ramping up to 70%
- G.M. Shrum: 15% ramping up to 25%.

Subsequent BC Hydro Load Forecasts, after the 2012 Forecast, did not provide information on service percentages.

2.41.5 If the "forecast period" in BC Hydro's response to Ince IR 1.6.4 ends in 20 years, why is BC Hydro forecasting 0% service percentage for the Chetwynd and Fox/Fort St. John areas? Does

BC Hydro have any plan to provide electrical service to gas producing facilities in those areas?

RESPONSE:

Please refer to BC Hydro’s response to CEABC IR 2.41.1.

42.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.10.4, Appendix O, Load Forecast Report, Section 7.5.2.2.1, Other large oil and gas operations segment description

BC Hydro's response to CEABC IR 1.10.4 includes the statement:

"A customer's decision to use BC Hydro electricity supply for their project is driven by a number of factors that include cost, proximity to existing electrical infrastructure with available capacity, and confidence in the in-service date of the interconnection.

BC Hydro Key Account Managers regularly meet with customers and prospective customers to discuss existing and future potential projects within the province. This includes working to identify the locations of existing and potential compressor stations relative to existing electrical infrastructure. We also actively assist customers through the interconnection process to manage customer in-service dates"

Spectra Energy Transmission is planning to change out power equipment at their Compressor Station N5 along their gas pipeline between Hudson's Hope and Pink Mountain. This is part of their Spruce Ridge Program, summarized at; https://www.enbridge.com/projects-and-infrastructure/projects/spruce-ridge-program#projectdetails:program-scope

On December 10, 2018 the National Energy Board approved the Spruce Ridge Program. The NEB filed Spectra's Technical Description of the Program at https://apps.neb-one.gc.ca/REGDOCS/Item/View/3350582

The Technical Description states: "The expansion at CS N5 includes the addition of a new compressor package consisting of a multi-stage centrifugal compressor driven by a lean burn 30,000 HP (22.4 MW ISO) natural gas turbine engine and associated equipment."

Compressor Station N5 is located approximately 24 km north west of Hudson's Hope. BC Hydro has several large and small transmission lines that run through or are near Hudson's Hope.

2.42.1 What is the status of BC Hydro's discussions with Spectra about using BC Hydro's clean electricity supply rather than natural gas to power their new compressor at station N-5?

RESPONSE:

The public version of the response has been redacted to maintain confidentiality over customer information. The un-redacted version of the response is being

made available to the BCUC only, in order to protect the customer's commercial interests.

Enbridge purchased Spectra Energy in 2017.

[redacted]

[redacted]

43.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.6.4, and Exhibit B-1, the Application, Appendix A, Schedule 4.0, the variability of Surplus Sales

BC Hydro's response to CEABC IR 1.6.4. provided a table in Attachment 1 to that response. However, the response also stated:

"Fiscal 2019 actual results are unaudited and unapproved and therefore are not yet available."

The note at the bottom of the table in Attachment 1 stated

"F2019 Forecast includes six months of actuals from April to September."

2.43.1 Please update the table provided in Attachment 1 to CEABC IR 1.6.4 to include the totals of the 3 items, on the same monthly basis, for the last ten years, and provide the actuals from October 1, 2018 to March 31, 2019 as soon as they are approved and available.

RESPONSE:

The data requested is provided in Attachment 1 to this response. BC Hydro notes that the line references in Appendix A changed in the Application, which is why the line references for fiscal 2019 differ from previous fiscal years.

Cost of Energy: Purchases and Sales
F2010 - F2019

(GWh)	Schedule Reference	F2010 Actual Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	F2010 Total
Market Electricity Purchases	4.0 L3	677	80	33	12	148	442	454	188	2	-	-	125	2,161
Surplus Sales	4.0 L6	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Purchases (Sales) from Powerex	4.0 L2	(8)	250	632	530	11	29	319	107	(467)	(417)	(114)	653	1,525
Subtotal		**669**	**330**	**665**	**542**	**159**	**471**	**773**	**295**	**(465)**	**(417)**	**(114)**	**778**	**3,686**

(GWh)	Schedule Reference	F2011 Actual Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	F2011 Total
Market Electricity Purchases	4.0 L3	196	307	175	317	471	852	665	148	16	219	206	220	3,791
Surplus Sales	4.0 L6	-	-	44	(95)	(2)	-	-	-	-	-	-	-	(53)
Net Purchases (Sales) from Powerex	4.0 L2	383	-	236	(3)	69	67	45	42	(252)	211	203	78	1,077
Subtotal		**579**	**307**	**454**	**219**	**538**	**919**	**710**	**190**	**(237)**	**430**	**409**	**298**	**4,815**

(GWh)	Schedule Reference	F2012 Actual Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	F2012 Total
Market Electricity Purchases	4.0 L3	389	96	71	1	-	-	0	1	39	13	8	222	840
Surplus Sales	4.0 L6	-	-	-	(89)	(398)	(223)	0	-	-	-	-	-	(710)
Net Purchases (Sales) from Powerex	4.0 L2	70	(105)	(93)	(678)	(927)	(615)	(443)	(304)	(530)	(265)	(188)	86	(3,993)
Subtotal		**458**	**(9)**	**(22)**	**(766)**	**(1,324)**	**(837)**	**(443)**	**(303)**	**(491)**	**(252)**	**(180)**	**307**	**(3,862)**

(GWh)	Schedule Reference	F2013 Actual Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	F2013 Total
Market Electricity Purchases	4.0 L3	4	15	18	0	0	3	52	8	62	47	69	80	359
Surplus Sales	4.0 L6	(196)	(829)	(834)	(1,467)	(1,280)	(431)	(313)	(115)	(23)	(364)	(170)	1	(6,020)
Net Purchases (Sales) from Powerex	4.0 L2	44	19	24	(0)	0	(65)	(41)	(223)	4	(128)	(192)	(325)	(883)
Subtotal		**(148)**	**(795)**	**(791)**	**(1,466)**	**(1,280)**	**(493)**	**(302)**	**(329)**	**44**	**(445)**	**(293)**	**(244)**	**(6,543)**

(GWh)	Schedule Reference	F2014 Actual Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	F2014 Total
Market Electricity Purchases	4.0 L3	21	11	11	0	1	1	1,042	(339)	21	62	47	40	918
Surplus Sales	4.0 L6	(1)	(120)	(134)	(226)	(303)	(178)	0	(33)	(15)	1	-	-	(1,008)
Net Purchases (Sales) from Powerex	4.0 L2	343	25	58	270	199	109	19	11	(33)	(151)	(2)	516	1,365
Subtotal		**363**	**(83)**	**(66)**	**45**	**(102)**	**(68)**	**1,062**	**(361)**	**(28)**	**(87)**	**45**	**556**	**1,275**

(GWh)	Schedule Reference	F2015 Actual Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	F2015 Total
Market Electricity Purchases	4.0 L3	21	5	9	13	1	0	4	13	27	42	39	33	207
Surplus Sales	4.0 L6	-	(2)	(9)	(4)	-	-	-	-	-	-	-	-	(15)
Net Purchases (Sales) from Powerex	4.0 L2	449	83	100	(56)	(180)	(52)	242	104	38	(302)	101	(15)	512
Subtotal		**470**	**86**	**100**	**(47)**	**(179)**	**(52)**	**246**	**117**	**65**	**(259)**	**140**	**18**	**705**

(GWh)	Schedule Reference	F2016 Actual Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	F2016 Total
Market Electricity Purchases	4.0 L3	4	0	1	0	2	1	1	8	16	15	36	39	122
Surplus Sales	4.0 L6	(804)	(1,008)	(904)	(676)	(858)	(768)	(69)	(225)	(292)	(669)	(2)	(4)	(6,277)
Net Purchases (Sales) from Powerex	4.0 L2	(173)	(53)	(17)	(10)	43	(26)	(103)	(47)	123	3	96	157	(6)
Subtotal		**(972)**	**(1,061)**	**(921)**	**(685)**	**(813)**	**(793)**	**(171)**	**(263)**	**(153)**	**(651)**	**131**	**192**	**(6,162)**

(GWh)	Schedule Reference	F2017 Actual Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	F2017 -
Market Electricity Purchases	4.0 L3	6	1	4	4	1	9	2	23	11	2	31	36	131
Surplus Sales	4.0 L6	(99)	(823)	(971)	(922)	(767)	(246)	(132)	(516)	(433)	(750)	(83)	(14)	(5,756)
Net Purchases (Sales) from Powerex	4.0 L2	50	(7)	0	(16)	3	130	183	(14)	(381)	(26)	(0)	216	138
Subtotal		**(43)**	**(828)**	**(966)**	**(935)**	**(763)**	**(107)**	**54**	**(508)**	**(804)**	**(773)**	**(52)**	**238**	**(5,488)**

(GWh)	Schedule Reference	F2018 Actual Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	F2018 Total
Market Electricity Purchases	4.0 L3	11	7	5	5	0	3	2	3	4	41	26	42	150
Surplus Sales	4.0 L6	(64)	(435)	(716)	(1,042)	(1,132)	(945)	(283)	(74)	(210)	(120)	(37)	(13)	(5,072)
Net Purchases (Sales) from Powerex	4.0 L2	103	4	45	(16)	7	(58)	(159)	(192)	(531)	(1)	131	109	(557)
Subtotal		**50**	**(425)**	**(666)**	**(1,053)**	**(1,125)**	**(999)**	**(440)**	**(263)**	**(736)**	**(80)**	**120**	**138**	**(5,479)**

(GWh)	Schedule Reference	F2019 Actual Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	F2019 Total
Market Electricity Purchases	4.0 L8	17	7	16	4	3	4	2	363	220	189	260	950	2,035
Surplus Sales	4.0 L9	(2)	(401)	(357)	(795)	(676)	2	-	-	-	-	-	-	(2,230)
Net Purchases (Sales) from Powerex	4.0 L10	313	58	51	(68)	34	24	(217)	192	170	(80)	(303)	473	647
Subtotal		**328**	**(336)**	**(290)**	**(859)**	**(639)**	**30**	**(215)**	**555**	**390**	**110**	**(43)**	**1,423**	**452**

44.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.14.1, John Hart project in the Campbell River System.

In its response, BC Hydro states: "The value of John Hart Facility's average energy is $132/MWh ($F2012), which is the levelized Clean Power Call firm energy price, adjusted for delivery to the LM (including transmission losses" and other factors, escalated and rounded."

2.44.1 Is the $132/MWh ($F2012) figure the average Price or is it in the upper range of the levelized energy prices accepted in the Clean Power Call? What is the average price?

RESPONSE:

The $132/MWh (fiscal 2012$) is the weighted-average of the levelized adjusted firm energy prices (FEP) of contracts awarded pursuant to the Clean Power Call request for proposals (RFP).

The levelized adjusted FEP includes adjustments to account for differences in product attributes, and in project location relative to the Lower Mainland. Adjustments were made for hourly firm energy, wind integration, Network Upgrade costs borne by BC Hydro, Cost of Incremental Firm Transmission and energy losses. The result of these adjustments is a levelized adjusted FEP on a stand-alone basis for a common product (i.e., seasonally firm energy delivered to the Lower Mainland).

Excluding the adjustments described above, the weighted-average levelized FEP at the plant gate for the awarded contracts was $118/MWh (fiscal 2012$).

The prices above were adjusted from fiscal 2009$ (as reported when the Clean Power Call RFP results were announced in 2010) to fiscal 2012$ (as used in the John Hart Generating Station Replacement Project CPCN Application).

45.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.19.2, Non-Treaty Storage Agreement

In its response, BC Hydro states: “BC Hydro energy benefits under NTSA are either settled financially (default option) or delivered to the BC/US border to serve BC domestic load"

2.45.1 While the CEABC appreciates the complexity of the build and release provisions of the Non-Treaty Storage Agreement, on an average annual basis, how much energy can BC Hydro expect to be delivered to it at the BC/US border to serve B.C. domestic load?

RESPONSE:

Since 2012 when the current Non-Treaty Storage Agreement was signed, all transactions have been settled financially. As such, there have been are no energy deliveries to B.C./U.S. border.

In BC Hydro’s planning view and its calculation of average energy available to serve load, BC Hydro assumes approximately 100 GWh per year is available from the Non-Treaty Storage Agreement.

45.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.19.2, Non-Treaty Storage Agreement

In its response, BC Hydro states: "BC Hydro energy benefits under NTSA are either settled financially (default option) or delivered to the BC/US border to serve BC domestic load"

2.45.2 Please confirm that U.S. transmission charges and losses for energy delivered to the BC/US border are for the account of the Bonneville Power Administration/Mid-C Participants.

RESPONSE:

The delivery point under the Non-Treaty Storage Agreement is the B.C./U.S. border. Were physical deliveries to occur, the party who delivered the energy would be responsible for transmission charges. For example, Bonneville Power Administration (Bonneville) pays wheeling charges and losses for physical deliveries to BC Hydro that are delivered at the B.C./U.S. border.

The exception to this is for the "dry provision clause" where BC Hydro has the unilateral right to receive energy deliveries. Under this event, BC Hydro compensates Bonneville for the wheeling charges and losses for energy deliveries associated with the dry release provisions. Wheeling charges are based on the posted Bonneville hourly non-firm point-to-point transmission and ancillary service rates. Losses are based on the posted Bonneville transmission losses product rate.

45.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.19.2, Non-Treaty Storage Agreement

In its response, BC Hydro states: “BC Hydro energy benefits under NTSA are either settled financially (default option) or delivered to the BC/US border to serve BC domestic load"

2.45.3 From a planning view, how is the energy delivered at the BC/US border to serve BC domestic load identified in BC Hydro’s load resource balance? For example does BC Hydro consider it be IPP energy/capacity? Or is it heritage energy? Or other? Where is it classified?

RESPONSE:

From a planning view, BC Hydro classifies the energy that can be delivered at the B.C./U.S. border to serve B.C. domestic load as Heritage Energy.

This is consistent with how BC Hydro accounts for the Non-Treaty Storage Agreement, where costs/(recoveries) are included in Heritage Energy (see schedule 4.0, line 26 of Appendix A); and any variances are deferred to the Heritage Deferral Account.

45.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.19.2, Non-Treaty Storage Agreement

In its response, BC Hydro states: "BC Hydro energy benefits under NTSA are either settled financially (default option) or delivered to the BC/US border to serve BC domestic load"

2.45.4 If this energy is not delivered to the BC/US border to serve BC domestic load (i.e. the default option occurs), then what would the revenue to BC Hydro be on an average annual basis? For clarity, please describe how this amount is calculated including any U.S. transmission charges and losses for the account of BC Hydro and whether the revenue is being expressed in U.S. or Canadian dollars. How is this revenue recorded in BC Hydro's accounts?

RESPONSE:

When BC Hydro drafts from its Non-Treaty account, Bonneville Power Administration (Bonneville) will see extra generation at the Federal projects in the U.S. As a result, Bonneville credits BC Hydro for the incremental energy valued at the Mid-C market price at the time of release. These transactions are recorded as a cost recovery in Cost of Energy. Conversely, when BC Hydro refills its Non-Treaty account, Bonneville will see reduced generation at the Federal projects and BC Hydro owes Bonneville energy valued at Mid-C market price at the time of storage. These storage transactions are recorded as a cost in Cost of Energy.

The net dollar benefit to BC Hydro under the Non-Treaty Storage Agreement (NTSA) for any given year is the sum of all BC Hydro release and storage transactions. The annual benefits can vary from a negative amount to a positive amount depending on whether there is a net draft or storage of BC Hydro's Non-Treaty account on August 31 of each year, the date on which the dollar balance in the account is settled with Bonneville. The average annual NTSA benefit over the past seven years has been about US$16 million.

Please refer to BC Hydro's response to CEABC IR 2.45.2 for a description of transmission charges and losses.

45.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.19.2, Non-Treaty Storage Agreement

In its response, BC Hydro states: “BC Hydro energy benefits under NTSA are either settled financially (default option) or delivered to the BC/US border to serve BC domestic load"

2.45.5 Does Powerex participate in the administration of the Non-Treaty Storage Agreement or have any other involvement with respect to it? If yes please provide the details.

RESPONSE:

Powerex does not participate in the administration of the Non-Treaty Storage Agreement. The decision to release or store water is with BC Hydro. BC Hydro and Powerex regularly discuss system operations, import and export activity. Powerex also provides BC Hydro with Mid-C price forecasts which may impact BC Hydro’s decisions regarding release or storage of water under the Non-Treaty Storage Agreement.

45.0 Reference: Exhibit B-6, BC Hydro response to CEABC IR 1.19.2, Non-Treaty Storage Agreement

In its response, BC Hydro states: “BC Hydro energy benefits under NTSA are either settled financially (default option) or delivered to the BC/US border to serve BC domestic load"

2.45.6 Please provide the quantity of energy that has been delivered under each of the Canadian Entitlement and the NTSA to the BC/US border to serve BC domestic load for each month of the past 10 years. Is it mandatory that the Downstream Benefits under the Columbia Treaty first be delivered to the B.C./U.S. border before they can be sold in the U.S.?

RESPONSE:

Since 2012, when the current Non-Treaty Storage Agreement was signed, all of the transactions have been settled financially. BC Hydro has not received energy deliveries at the B.C./U.S. border from the Bonneville Power Authority (Bonneville).

The table below provides the Canadian Entitlement for the last ten years in average megawatts. The monthly volumes delivered as part of the Canadian Entitlement are identical for each month in the operating year (beginning in August through July). For example, the volume delivered in August 2009 and September 2009 and the remaining ten months of the 2009/2010 operating year is 567.1 MW per month. For simplicity, the table presents the data annualized per operating year rather than repeat the figure twelve times.

Operating Year (August thru July)*	Canadian Entitlement Energy (Average MW per month)
2009/2010	567.1
2010/2011	535.7
2011/2012	525.9
2012/2013	504.5
2013/2014	505.5
2014/2015	479.9
2015/2016	488.7
2016/2017	484.0
2017/2018	475.0
2018/2019	472.5

*** The Operating Year in the Columbia River Treaty refers to the August to July period. For example, Operating Year 2018/2019 refers to August 2018 to July 2019.**

The U.S. Entity (Bonneville) is obligated under the Aspects Agreement to deliver the Canadian Entitlement at the B.C./U.S. border. It is received by Powerex at this point and scheduled to the BC Hydro system, where it is aggregated with other transactions for allocation under the Transfer Pricing Agreement either to Market Electricity Purchases or Net Purchases (Sales) from Powerex.

There are provisions for the Canadian Entity to change the point of delivery to a location within the U.S. subject to the agreement of the U.S. Entity. There are also provisions for temporary changes to the delivery point for operational reasons subject to the agreement of the Operating Committee representing the Entities.

A copy of the Aspects Agreement is available on the BCUC website: https://www.bcuc.com/Documents/Proceedings/2006/DOC_10966_B1-131_Columbia%20River%20Treaty%20Agree.pdf.

46.0 Reference: Miscellaneous, WAC Bennett Dam

In a report entitled “BC Hydro, WAC Bennett Dam, Expert Engineering Panel, Report-Volume 1”, Kaare Hoeg, Robin Fell, Rodney Bridle, 13 August 2012, Report No. N3405 can be found the following statements:

(pages 48 and 49): “As the upper part of the Bennett Dam is generally still not saturated it therefore remains potentially susceptible to concentrated leak erosion in cracks or hydraulic fracture under high reservoir levels. Cracking or extension of low stress zones susceptible to hydraulic fracture in the upper part of the dam may occur under seismic conditions. The Panel has recommended further investigations into the high fines content and cementation issues.”

(page 57): “(b) Carry out investigations to determine whether the Transition in the upper part of the dam may hold a crack”

2.46.1 Please describe how BC Hydro has responded to the matters set out above.

RESPONSE:

In response to the recommendations in the 2012 report[1] referenced in this question, and in accordance with current dam industry practices, BC Hydro performed investigations into factors that determine the susceptibility of the Core and Transition fill materials to hydraulic fracture and concentrated leak erosion in cracks. The results indicated that the Transition can be expected to arrest erosion of the Core due to cracking that may occur for any reason; any cracks in the Core or Transition that may develop are expected to close when they become saturated. Moreover, based on our analyses, cracks that develop in the upper part of the dam under seismic conditions are not expected to extend down to the maximum water level permitted in the reservoir and thus not be subjected to concentrated leak erosion. The results of these investigations were accepted at a meeting of the Expert Engineering Panel (EEP) in 2015 and documented in the EEP’s March 2016 Report.[2]

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1 **BC Hydro WAC Bennett Dam Expert Engineering Panel Report – Volume 1 dated August 13, 2012, Report No. N3405, available at: www.bchydro.com/content/dam/BCHydro/customer-portal/documents/projects/gm-shrum/EEP%20report_V1.pdf.**

2 **BC Hydro WAC Bennett Dam Expert Engineering Panel Report dated March 24, 2016, Report No. N3862, available at www.bchydro.com/content/dam/BCHydro/customer-portal/documents/projects/gm-shrum/2016-bchydro-eep-transmittal-letter-and-report.pdf.**

There are recognized limitations in the current dam industry practices referred to above, leading to uncertainties in the derived results. It is further recognized that WAC Bennett Dam is of great economic importance and poses an extreme consequence in the event of its failure. In light of these facts, BC Hydro is performing additional work to reduce the uncertainties in the results that have been obtained thus far, and to follow the additional guidance provided in the EEP's March 2016 Report, as follows:

- **Perform large-scale crack box testing in which a crack is induced in the Transition materials and water is introduced into the crack to determine whether the Transition materials will collapse;**
- **Prepare a design to extend the filter and potentially the drain to increase the filtering capability to the Core at the upper part of the dam; and**
- **Perform three-dimensional modelling of the spillway and embankment dam interface.**

This work has been initiated and it is currently expected to be completed in 2023. Given the complexity of these engineering activities and, in particular, the state of the art nature of the large-scale testing, this time frame is only a preliminary estimate and may have to be extended.

47.0 Reference: Exhibit B-1, Appendix A, A Contextual History of BC Hydro's Revenue Requirements since F2007.

In order to obtain a longer term perspective with respect to the trends in BC Hydro's Revenue Requirements over time, CEABC has assembled the following table using data extracted from Appendix A of the F2020-21 RRA and also Appendix A of the previous RRA (F2017-19).

This data table will also be provided in a working Excel model.

GROSS & CURRENT BASIS	Summary History of BC Hydro Revenue Requirement from F2007 to F2018													Forecast F2019-F2021	
Revenue Requirements Summary ($ million)	Extracted from F17-19 RRA								Extracted from F20-21 RRA						
	Actual F07	Actual F08	Actual F09	Actual F10	Actual F11	Actual F12	Actual F13	Actual F14	Actual F15	Actual F16	Actual F17	Actual F18	Forecast F19	Plan F20	Plan F21
Cost of Energy (GROSS)	1,091.2	970.4	1,282.8	1,209.9	1,309.1	1,043.0	1,057.3	1,309.3	1,512.5	1,475.6	1,505.5	1,538.7	1,673.4	1,887.0	1,920.2
Deferral Account Transfers	*99.6*	*269.3*	*(216.7)*	*(16.6)*	*(155.5)*	*73.7*	*183.4*	*102.8*	*(204.9)*	*(195.9)*	*210.3*	*315.5*	*260.1*	*(152.0)*	*(152.0)*
Cost of Energy (CURRENT) (includes HDA & NHDA Rate Rider)	1,190.8	1,239.8	1,066.2	1,193.3	1,153.6	1,116.7	1,240.7	1,412.1	1,307.6	1,279.7	1,715.8	1,854.1	1,933.5	1,735.1	1,768.2
Operating Costs (GROSS)	645.7	885.6	831.1	1,186.6	909.7	1,452.0	1,307.8	1,232.2	1,303.0	1,251.6	1,165.1	1,228.7	1,257.5	1,224.2	1,229.3
Regulatory Account Transfers	*(89.7)*	*(334.9)*	*(182.6)*	*(540.7)*	*(153.0)*	*(506.5)*	*(378.5)*	*(457.3)*	*(367.0)*	*(265.8)*	*(174.2)*	*(255.9)*	*849.5*	*74.3*	*75.9*
Operating Costs (CURRENT) (includes Rate Smoothing & Gov't	556.0	550.7	648.6	645.9	756.7	945.5	929.3	774.9	936.0	985.7	990.9	972.8	2,107.1	1,298.6	1,305.2
Reverse Rate Smoothing & Gov't adjustment	-	-	-	-	-	(69.7)	(41.2)	110.9	166.2	121.2	201.2	326.2	(814.9)	-	-
Operating Costs (CURRENT) (before Rate Smoothing & Gov't adjustment)	**556.0**	**550.7**	**648.6**	**645.9**	**756.7**	**875.8**	**888.1**	**885.8**	**1,102.2**	**1,106.9**	**1,192.2**	**1,299.0**	**1,292.2**	**1,298.6**	**1,305.2**
Taxes (GROSS)	147.1	158.6	166.7	172.6	177.4	184.2	194.1	202.1	206.1	213.1	223.1	231.1	242.2	249.8	262.2
Regulatory Account Transfers	-	-	*1.7*	*5.5*	*5.6*	*(14.0)*	-	-	*2.6*	*3.4*	*0.4*	*1.9*	-	-	-
Taxes (CURRENT)	147.1	158.6	168.4	178.1	183.0	170.2	194.1	202.1	208.7	216.5	223.5	232.9	242.2	249.8	262.2
Amortization (GROSS)	378.5	363.4	388.0	437.4	501.4	586.2	635.0	656.8	691.7	739.5	777.9	807.6	871.5	915.7	936.5
Finance Charges (GROSS)	456.0	434.5	495.1	384.0	495.4	558.6	576.3	652.2	664.1	746.6	579.2	805.9	684.6	757.5	726.9
Return on Equity (GROSS)	407.0	369.0	365.6	447.0	588.9	558.4	509.3	549.5	580.8	655.0	683.5	684.0	(424.3)	712.0	712.0
Total Capital-Based Charges (GROSS)	**1,242**	**1,167**	**1,249**	**1,268**	**1,586**	**1,703**	**1,721**	**1,859**	**1,937**	**2,141**	**2,041**	**2,298**	**1,132**	**2,385**	**2,375**
Regulatory Account Transfers	*(11.0)*	*35.0*	*(11.6)*	*54.7*	*(88.3)*	*(93.1)*	*(40.1)*	*(82.9)*	*2.0*	*44.5*	*7.6*	*(184.1)*	*(49.6)*	*59.9*	*59.1*
Amortization (CURRENT)	362.9	373.4	405.9	442.1	536.1	552.4	631.7	655.0	739.9	804.3	860.7	916.3	950.8	1,035.6	1,060.2
Finance Charges (CURRENT)	460.6	459.4	465.7	490.4	361.1	490.2	538.4	576.0	606.7	726.3	504.0	513.1	555.6	697.5	662.3
Return on Equity (CURRENT)	407.0	369.0	365.6	390.6	600.2	567.6	510.3	544.7	592.1	655.0	683.5	684.0	(424.3)	712.0	712.0
Total Capital-Based Charges (CURRENT)	**1,231**	**1,202**	**1,237**	**1,323**	**1,497**	**1,610**	**1,681**	**1,776**	**1,939**	**2,186**	**2,048**	**2,113**	**1,082**	**2,445**	**2,434**
Powerex Net Income (GROSS)	(259.2)	(82.7)	(243.9)	(7.5)	(71.5)	(142.0)	(98.2)	58.4	(120.1)	(58.7)	(130.2)	(136.6)	(205.3)	(120.6)	(120.6)
Deferral Account Transfers	*(27.0)*	*(111.1)*	*(28.6)*	*(198.5)*	*(57.0)*	*20.7*	*25.2*	*(122.5)*	*91.4*	*3.6*	*64.0*	*71.9*	*153.1*	*(12.6)*	*(12.6)*
Powerex Net Income (CURRENT)	(286.2)	(193.8)	(272.5)	(206.1)	(128.5)	(121.4)	(73.0)	(64.1)	(28.7)	(55.1)	(66.2)	(64.7)	(52.3)	(133.2)	(133.2)
Non-Tariff/Misc. Revenue (CURRENT)	(45.2)	(31.4)	(44.0)	(55.2)	(102.4)	(80.8)	(116.4)	(122.4)	(129.8)	(133.8)	(143.4)	(143.7)	(151.6)	(237.7)	(243.7)
Inter-Segment Revenue (CURRENT)	(42.6)	(68.7)	30.5	(60.9)	(89.2)	(30.1)	(63.1)	(27.1)	(50.6)	(55.7)	(56.9)	(66.4)	(64.3)	(69.0)	(72.6)
Powertech Net Income (CURRENT)	(1.2)	(0.5)	(1.2)	(0.7)	(0.5)	(2.6)	(2.9)	(3.7)	(4.4)	(4.2)	(2.1)	(3.1)	(3.3)	(3.4)	(3.7)
Other Utilities Revenue (CURRENT)	(18.4)	(15.4)	(22.0)	(16.3)	(16.3)	(14.9)	(14.8)	(16.4)	(18.6)	(18.2)	(13.0)	(11.9)	(28.6)	(28.6)	(28.7)
Liquefied Natural Gas Revenue (CURRENT)	-	-	-	-	-	-	-	-	-	-	(0.4)	(1.3)	(0.3)	-	-
Total Other Incomes (CURRENT)	**(393.6)**	**(309.8)**	**(309.2)**	**(339.1)**	**(336.8)**	**(249.8)**	**(270.2)**	**(233.8)**	**(232.0)**	**(267.0)**	**(282.1)**	**(291.1)**	**(300.4)**	**(471.9)**	**(481.8)**
Total Revenue Requirement (including Rate Rider before Rate Smoothing)	**2,731**	**2,841**	**2,811**	**3,001**	**3,254**	**3,523**	**3,733**	**4,042**	**4,325**	**4,522**	**4,898**	**5,208**	**4,250**	**5,256**	**5,288**
Rate Smoothing & Gov't adjustment	-	-	-	-	-	69.7	41.2	(110.9)	(166.2)	(121.2)	(201.2)	(326.2)	814.9	-	-
Total RR after rate Smoothing (incl Rate Rider)	**2,731**	**2,841**	**2,811**	**3,001**	**3,254**	**3,593**	**3,774**	**3,931**	**4,159**	**4,400**	**4,696**	**4,882**	**5,065**	**5,256**	**5,288**
reverse Deferral Rate Rider	(10.1)	(55.7)	(14.0)	(29.7)	(112.9)	(87.7)	(179.7)	(187.2)	(198.1)	(209.5)	(223.7)	(233.2)	(241.2)	-	-
Total Rate Revenue Requirement after Rate Smoothing but before Deferral	**2,720.7**	**2,785.5**	**2,796.9**	**2,971.6**	**3,141.1**	**3,505.2**	**3,594.7**	**3,743.9**	**3,961.0**	**4,190.9**	**4,472.6**	**4,649.1**	**4,823.4**	**5,256.5**	**5,288.3**
Check balances against Schedule 3.0	2,720.7	2,785.5	2,796.9	2,971.6	3,141.1	3,505.2	3,594.7	3,743.9	3,961.0	4,190.9	4,472.6	4,649.1	4,823.4	5,256.5	5,288.3

2.47.1 Please verify the data assembled in this table, and confirm that CEABC has extracted the information correctly from the two Appendix As. If any errors are found, please provide the corrected values with an explanation of the error.

RESPONSE:

BC Hydro confirms that CEABC has extracted the individual line items correctly from Appendix A of the Application and from Appendix A of the Previous Application.

However, the classification of some of the items in the data table does not correspond to the presentation format in BC Hydro's other regular financial reporting and regulatory filings. For example, BC Hydro does not use the term "Total Capital-Based Charges", and views inclusion of the Return on Equity into this category as an incorrect classification since the allowed return on equity is set without any relation to capital.

In the absence of further information, BC Hydro is unable to confirm whether this data table is suitable for analysis.

47.0 Reference: Exhibit B-1, Appendix A, A Contextual History of BC Hydro's Revenue Requirements since F2007.

In order to obtain a longer term perspective with respect to the trends in BC Hydro's Revenue Requirements over time, CEABC has assembled the following table using data extracted from Appendix A of the F2020-21 RRA and also Appendix A of the previous RRA (F2017-19).

This data table will also be provided in a working Excel model.

GROSS & CURRENT BASIS	Summary History of BC Hydro Revenue Requirement from F2007 to F2018													Forecast F2019-F2021		
Revenue Requirements Summary ($ million)	Extracted from F17-19 RRA								Extracted from F20-21 RRA							
	Actual F07	Actual F08	Actual F09	Actual F10	Actual F11	Actual F12	Actual F13	Actual F14	Actual F15	Actual F16	Actual F17	Actual F18	Forecast F19	Plan F20	Plan F21
Cost of Energy (GROSS)	1,091.2	970.4	1,282.8	1,209.9	1,309.1	1,043.0	1,057.3	1,309.3	1,512.5	1,475.6	1,505.5	1,538.7	1,673.4	1,887.0	1,920.2
Deferral Account Transfers	*99.6*	*269.3*	*(216.7)*	*(16.6)*	*(155.5)*	*73.7*	*183.4*	*102.8*	*(204.9)*	*(195.9)*	*210.3*	*315.5*	*260.1*	*(152.0)*	*(152.0)*
Cost of Energy (CURRENT) (includes HDA & NHDA Rate Rider)	1,190.8	1,239.8	1,066.2	1,193.3	1,153.6	1,116.7	1,240.7	1,412.1	1,307.6	1,279.7	1,715.8	1,854.1	1,933.5	1,735.1	1,768.2
Operating Costs (GROSS)	645.7	885.6	831.1	1,186.6	909.7	1,452.0	1,307.8	1,232.2	1,303.0	1,251.6	1,165.1	1,228.7	1,257.5	1,224.2	1,229.3
Regulatory Account Transfers	*(89.7)*	*(334.9)*	*(182.6)*	*(540.7)*	*(153.0)*	*(506.5)*	*(378.5)*	*(457.3)*	*(367.0)*	*(265.8)*	*(174.2)*	*(255.9)*	*849.5*	*74.3*	*75.9*
Operating Costs (CURRENT) (includes Rate Smoothing & Gov't	556.0	550.7	648.6	645.9	756.7	945.5	929.3	774.9	936.0	985.7	990.9	972.8	2,107.1	1,298.6	1,305.2
Reverse Rate Smoothing & Gov't adjustment	-	-	-	-	-	(69.7)	(41.2)	110.9	166.2	121.2	201.2	326.2	(814.9)	-	-
Operating Costs (CURRENT) (before Rate Smoothing & Gov't adjustment)	**556.0**	**550.7**	**648.6**	**645.9**	**756.7**	**875.8**	**888.1**	**885.8**	**1,102.2**	**1,106.9**	**1,192.2**	**1,299.0**	**1,292.2**	**1,298.6**	**1,305.2**
Taxes (GROSS)	147.1	158.6	166.7	172.6	177.4	184.2	194.1	202.1	206.1	213.1	223.1	231.1	242.2	249.8	262.2
Regulatory Account Transfers	-	-	*1.7*	*5.5*	*5.6*	*(14.0)*	-	-	*2.6*	*3.4*	*0.4*	*1.9*	-	-	-
Taxes (CURRENT)	147.1	158.6	168.4	178.1	183.0	170.2	194.1	202.1	208.7	216.5	223.5	232.9	242.2	249.8	262.2
Amortization (GROSS)	378.5	363.4	388.0	437.4	501.4	586.2	635.0	656.8	691.7	739.5	777.9	807.6	871.5	915.7	936.5
Finance Charges (GROSS)	456.0	434.5	495.1	384.0	495.4	558.6	576.3	652.2	664.1	746.6	579.2	805.9	684.6	757.5	726.9
Return on Equity (GROSS)	407.0	369.0	365.6	447.0	588.9	558.4	509.3	549.5	580.8	655.0	683.5	684.0	(424.3)	712.0	712.0
Total Capital-Based Charges (GROSS)	**1,242**	**1,167**	**1,249**	**1,268**	**1,586**	**1,703**	**1,721**	**1,859**	**1,937**	**2,141**	**2,041**	**2,298**	**1,132**	**2,385**	**2,375**
Regulatory Account Transfers	*(11.0)*	*35.0*	*(11.6)*	*54.7*	*(88.3)*	*(93.1)*	*(40.1)*	*(82.9)*	*2.0*	*44.5*	*7.6*	*(184.1)*	*(49.6)*	*59.9*	*59.1*
Amortization (CURRENT)	362.9	373.4	405.9	442.1	536.1	552.4	631.7	655.0	739.9	804.3	860.7	916.3	950.8	1,035.6	1,060.2
Finance Charges (CURRENT)	460.6	459.4	465.7	490.4	361.1	490.2	538.4	576.0	606.7	726.3	504.0	513.1	555.6	697.5	662.3
Return on Equity (CURRENT)	407.0	369.0	365.6	390.6	600.2	567.6	510.3	544.7	592.1	655.0	683.5	684.0	(424.3)	712.0	712.0
Total Capital-Based Charges (CURRENT)	**1,231**	**1,202**	**1,237**	**1,323**	**1,497**	**1,610**	**1,681**	**1,776**	**1,939**	**2,186**	**2,048**	**2,113**	**1,082**	**2,445**	**2,434**
Powerex Net Income (GROSS)	(259.2)	(82.7)	(243.9)	(7.5)	(71.5)	(142.0)	(98.2)	58.4	(120.1)	(58.7)	(130.2)	(136.6)	(205.3)	(120.6)	(120.6)
Deferral Account Transfers	*(27.0)*	*(111.1)*	*(28.6)*	*(198.5)*	*(57.0)*	*20.7*	*25.2*	*(122.5)*	*91.4*	*3.6*	*64.0*	*71.9*	*153.1*	*(12.6)*	*(12.6)*
Powerex Net Income (CURRENT)	(286.2)	(193.8)	(272.5)	(206.1)	(128.5)	(121.4)	(73.0)	(64.1)	(28.7)	(55.1)	(66.2)	(64.7)	(52.3)	(133.2)	(133.2)
Non-Tariff/Misc. Revenue (CURRENT)	(45.2)	(31.4)	(44.0)	(55.2)	(102.4)	(80.8)	(116.4)	(122.4)	(129.8)	(133.8)	(143.4)	(143.7)	(151.6)	(237.7)	(243.7)
Inter-Segment Revenue (CURRENT)	(42.6)	(68.7)	30.5	(60.9)	(89.2)	(30.1)	(63.1)	(27.1)	(50.6)	(55.7)	(56.9)	(66.4)	(64.3)	(69.0)	(72.6)
Powertech Net Income (CURRENT)	(1.2)	(0.5)	(1.2)	(0.7)	(0.5)	(2.6)	(2.9)	(3.7)	(4.4)	(4.2)	(2.1)	(3.1)	(3.3)	(3.4)	(3.7)
Other Utilities Revenue (CURRENT)	(18.4)	(15.4)	(22.0)	(16.3)	(16.3)	(14.9)	(14.8)	(16.4)	(18.6)	(18.2)	(13.0)	(11.9)	(28.6)	(28.6)	(28.7)
Liquefied Natural Gas Revenue (CURRENT)	-	-	-	-	-	-	-	-	-	-	(0.4)	(1.3)	(0.3)	-	-
Total Other Incomes (CURRENT)	**(393.6)**	**(309.8)**	**(309.2)**	**(339.1)**	**(336.8)**	**(249.8)**	**(270.2)**	**(233.8)**	**(232.0)**	**(267.0)**	**(282.1)**	**(291.1)**	**(300.4)**	**(471.9)**	**(481.8)**
Total Revenue Requirement (including Rate Rider before Rate Smoothing)	**2,731**	**2,841**	**2,811**	**3,001**	**3,254**	**3,523**	**3,733**	**4,042**	**4,325**	**4,522**	**4,898**	**5,208**	**4,250**	**5,256**	**5,288**
Rate Smoothing & Gov't adjustment	-	-	-	-	-	69.7	41.2	(110.9)	(166.2)	(121.2)	(201.2)	(326.2)	814.9	-	-
Total RR after rate Smoothing (incl Rate Rider)	**2,731**	**2,841**	**2,811**	**3,001**	**3,254**	**3,593**	**3,774**	**3,931**	**4,159**	**4,400**	**4,696**	**4,882**	**5,065**	**5,256**	**5,288**
reverse Deferral Rate Rider	(10.1)	(55.7)	(14.0)	(29.7)	(112.9)	(87.7)	(179.7)	(187.2)	(198.1)	(209.5)	(223.7)	(233.2)	(241.2)	-	-
Total Rate Revenue Requirement after Rate Smoothing but before Deferral	**2,720.7**	**2,785.5**	**2,796.9**	**2,971.6**	**3,141.1**	**3,505.2**	**3,594.7**	**3,743.9**	**3,961.0**	**4,190.9**	**4,472.6**	**4,649.1**	**4,823.4**	**5,256.5**	**5,288.3**
Check balances against Schedule 3.0	2,720.7	2,785.5	2,796.9	2,971.6	3,141.1	3,505.2	3,594.7	3,743.9	3,961.0	4,190.9	4,472.6	4,649.1	4,823.4	5,256.5	5,288.3

2.47.2 Please explain what BC Hydro sees as the intended purpose(s) of the many Deferral and Regulatory Account Transfers that produce the differences between the Gross and Current basis of many of the cost categories. Do these transfers account for all of the differences between the Gross and Current values? If not, what portion?

RESPONSE:

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 a given year.

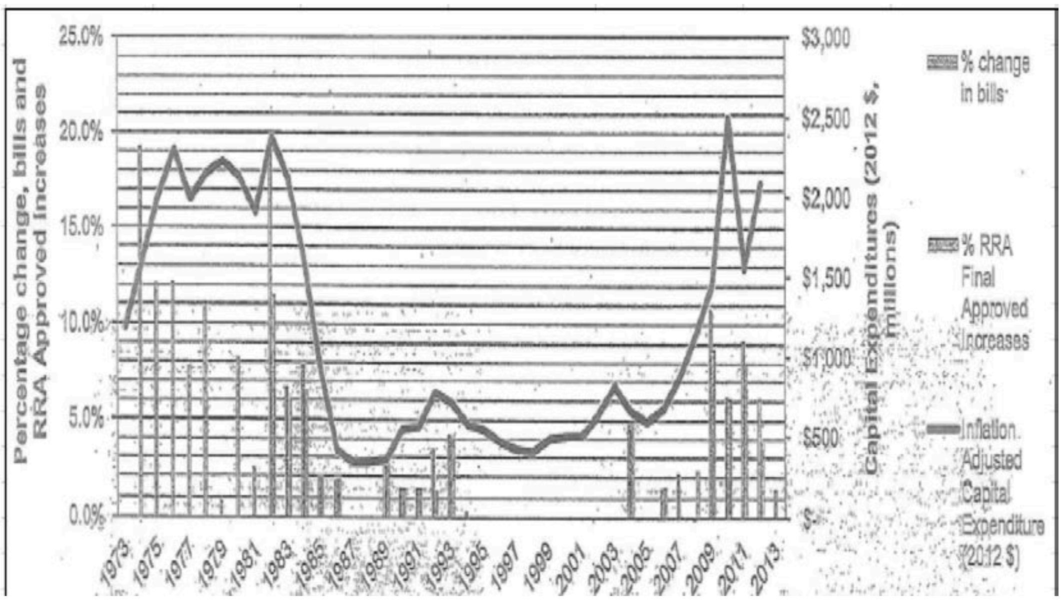
The Current View shows the total costs for each component of the revenue requirements after any forecast transfers to regulatory accounts. In other words, the Current View shows the actual costs being recovered from ratepayers in a given year.

BC Hydro confirms that the transfers to and from all deferral and regulatory accounts collectively account for the differences between Gross and Current values.

For further information on the types of regulatory accounts and their purpose, please refer to section 7.5 of Chapter 7 of the Application.

48.0 Reference: Further Contextual history of BC Hydro Revenue Requirements

On August 23, 2013 the BC Hydro Rates Working Group presented the following graph that compared Capital Expenditures, Revenue Requirement Application % Increases, and % Changes in Bills for each year from 1973 to 2013. (Apologies for the poor quality of the graphic.)

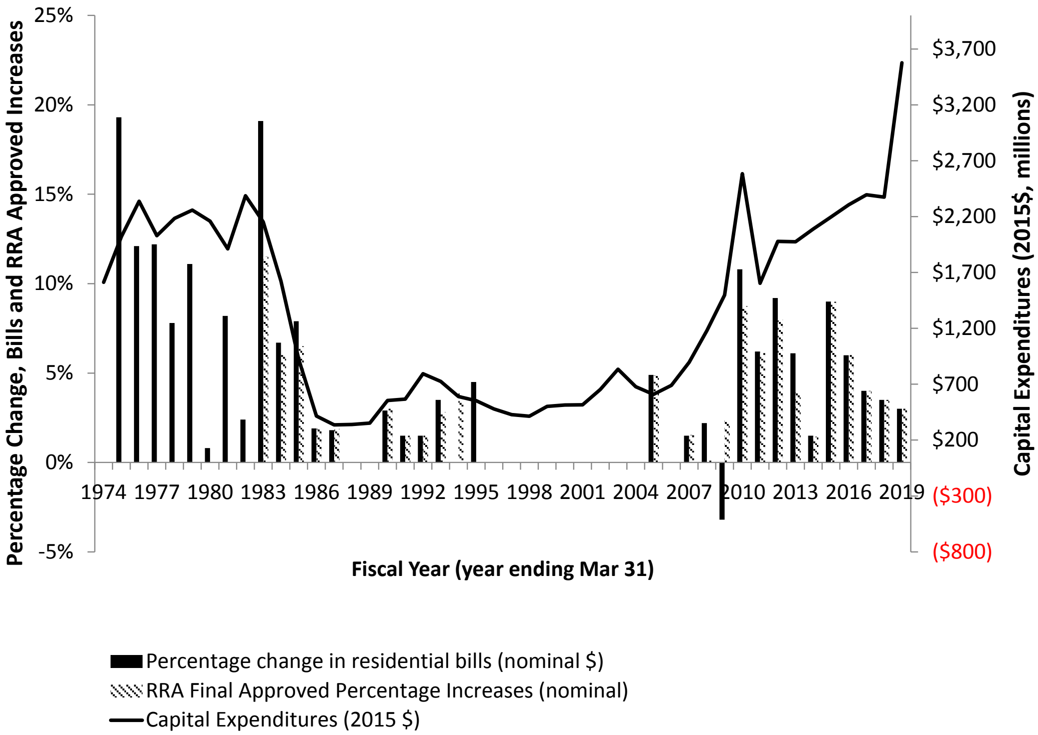


2.48.1 Please provide an updated chart to F2019, showing the same three items for each year from 1973 to F2019. Please also provide a spreadsheet showing the three amounts for each year and the inflation adjustment factors that have been used. Please include a working Excel model that can produce this updated chart.

RESPONSE:

An updated chart is provided below and a working Excel model is provided as Attachment 1 to this response.

Residential Bill Increases, RRA Approved Increases and Capital Expenditures (F1974 to F2019)



Note: **While rates increased in fiscal year 2009 due to the approved RRA rate increase, residential bills, based on 1,000 kWh monthly consumption, decreased as a result of the introduction of the Residential Inclining Block Rate on October 1, 2008.**

BC Hydro
Power smart

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(Accessible by opening the Attachments Tab in Adobe)

92.0 Reference: Exhibit B-6, CEC 1.4.1 and 1.4.2

1.4.1 The Comprehensive Review of BC Hydro resulted in a reduction of $2.7 billion from the 10-Year Capital Plan. Which of the above process presents an opportunity for the Commission to assess the success of BC Hydro's capital planning processes as a whole over time, including evaluating BC Hydro's implementation of the 10-Year Capital Plan?

RESPONSE:

The Comprehensive Review of BC Hydro did not drive the reduction of $2.7 billion to the 10-Year Capital Plan. BC Hydro completed an update of the 10-Year Capital Plan and submitted that update as part of the Comprehensive Review.

The success of our capital planning process as a whole over time is best assessed through the information provided in BC Hydro's Service Plan. The Service Plan contains performance measures such as SAIDI, SAIFI and Key Generating Facility Forced Outage Factor which provide an indication of the impact of capital investment on system performance over time. The 2019/20 – 2021/22 Service Plan is provided in Appendix E of the Application and section 6.3.2 of Chapter 6 of the Application provides a discussion of how recent trends in system performance informed the Capital Plan in the Application.

The Integrated Resource Plan process and the Revenue Requirements Application process provide an opportunity for the BCUC to assess BC Hydro's long-term plans and capital planning process, respectively.

RESPONSE:

As explained in BC Hydro's response to CEC IR 1.4.1, BC Hydro completed an update of the 10-Year Capital Plan as part of our capital planning process and this update informed the Comprehensive Review of BC Hydro.

BC Hydro evaluates success in its capital planning through ongoing achievement of Service Plan targets, demonstrating continuous improvements to the capital planning process and its governance, as well as third party evaluation of our asset management practices.

The Service Plan describes BC Hydro's goals, strategies, measures, and targets. BC Hydro management is responsible for measuring performance against these targets, and results are reported to BC Hydro's Board of Directors on a quarterly basis and publicly in the Annual Service Plan Report.

Two of the goals in the 2019/20 – 2021/22 Service Plan, provided in Appendix E to the Application, relate to the capital planning process: Reliable Service and Affordable Bills. Examples of performance measures for these goals include:

- System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Forced Outage Factor.
- Quartile ranking based on Hydro-Quebec's Comparison of Electricity Prices in Major North American Cities.

In addition, the achievement of the Safety goal in the Service Plan is also influenced by capital investment strategies.

2.92.1 Please provide the metrics by which BC Hydro believes the Integrated Resource Plan ("**IRP**") should be assessed.

RESPONSE:

BC Hydro's next IRP will be assessed by the BCUC. The factors or metrics by which the IRP should be assessed are best addressed in the IRP proceeding itself. However, without unduly pre-empting that process, BC Hydro can say that examples of considerations may include cost and reliability, and factors associated with the Government of B.C.'s energy policy such as the CleanBC Plan.

Please also refer to BC Hydro's response to CEC IR 1.41.1 which notes how our long term strategy is assessed through regular updates and reviews, and which of BC Hydro's Service Plan goals and measures relate to our long-term resource strategies.

92.0 Reference: Exhibit B-6, CEC 1.4.1 and 1.4.2

1.4.1 The Comprehensive Review of BC Hydro resulted in a reduction of $2.7 billion from the 10-Year Capital Plan. Which of the above process presents an opportunity for the Commission to assess the success of BC Hydro's capital planning processes as a whole over time, including evaluating BC Hydro's implementation of the 10-Year Capital Plan?

RESPONSE:

The Comprehensive Review of BC Hydro did not drive the reduction of $2.7 billion to the 10-Year Capital Plan. BC Hydro completed an update of the 10-Year Capital Plan and submitted that update as part of the Comprehensive Review.

The success of our capital planning process as a whole over time is best assessed through the information provided in BC Hydro's Service Plan. The Service Plan contains performance measures such as SAIDI, SAIFI and Key Generating Facility Forced Outage Factor which provide an indication of the impact of capital investment on system performance over time. The 2019/20 – 2021/22 Service Plan is provided in Appendix E of the Application and section 6.3.2 of Chapter 6 of the Application provides a discussion of how recent trends in system performance informed the Capital Plan in the Application.

The Integrated Resource Plan process and the Revenue Requirements Application process provide an opportunity for the BCUC to assess BC Hydro's long-term plans and capital planning process, respectively.

RESPONSE:

As explained in BC Hydro's response to CEC IR 1.4.1, BC Hydro completed an update of the 10-Year Capital Plan as part of our capital planning process and this update informed the Comprehensive Review of BC Hydro.

BC Hydro evaluates success in its capital planning through ongoing achievement of Service Plan targets, demonstrating continuous improvements to the capital planning process and its governance, as well as third party evaluation of our asset management practices.

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- System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Forced Outage Factor.
- Quartile ranking based on Hydro-Quebec's Comparison of Electricity Prices in Major North American Cities.

In addition, the achievement of the Safety goal in the Service Plan is also influenced by capital investment strategies.

2.92.1.1 Please identify how the Commission can assess the cost effectiveness of BC Hydro's IRP.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.92.1.

92.0 Reference: Exhibit B-6, CEC 1.4.1 and 1.4.2

1.4.1 The Comprehensive Review of BC Hydro resulted in a reduction of $2.7 billion from the 10-Year Capital Plan. Which of the above process presents an opportunity for the Commission to assess the success of BC Hydro's capital planning processes as a whole over time, including evaluating BC Hydro's implementation of the 10-Year Capital Plan?

RESPONSE:

The Comprehensive Review of BC Hydro did not drive the reduction of $2.7 billion to the 10-Year Capital Plan. BC Hydro completed an update of the 10-Year Capital Plan and submitted that update as part of the Comprehensive Review.

The success of our capital planning process as a whole over time is best assessed through the information provided in BC Hydro's Service Plan. The Service Plan contains performance measures such as SAIDI, SAIFI and Key Generating Facility Forced Outage Factor which provide an indication of the impact of capital investment on system performance over time. The 2019/20 – 2021/22 Service Plan is provided in Appendix E of the Application and section 6.3.2 of Chapter 6 of the Application provides a discussion of how recent trends in system performance informed the Capital Plan in the Application.

The Integrated Resource Plan process and the Revenue Requirements Application process provide an opportunity for the BCUC to assess BC Hydro's long-term plans and capital planning process, respectively.

RESPONSE:

As explained in BC Hydro's response to CEC IR 1.4.1, BC Hydro completed an update of the 10-Year Capital Plan as part of our capital planning process and this update informed the Comprehensive Review of BC Hydro.

BC Hydro evaluates success in its capital planning through ongoing achievement of Service Plan targets, demonstrating continuous improvements to the capital planning process and its governance, as well as third party evaluation of our asset management practices.

The Service Plan describes BC Hydro's goals, strategies, measures, and targets. BC Hydro management is responsible for measuring performance against these targets, and results are reported to BC Hydro's Board of Directors on a quarterly basis and publicly in the Annual Service Plan Report.

Two of the goals in the 2019/20 – 2021/22 Service Plan, provided in Appendix E to the Application, relate to the capital planning process: Reliable Service and Affordable Bills. Examples of performance measures for these goals include:

- System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Forced Outage Factor.
- Quartile ranking based on Hydro-Quebec's Comparison of Electricity Prices in Major North American Cities.

In addition, the achievement of the Safety goal in the Service Plan is also influenced by capital investment strategies.

2.92.2 Please explain how the Service Plan can be used by the Commission to determine the cost effectiveness of the ways by which BC Hydro achieves its performance metrics.

RESPONSE:

BC Hydro's Service Plan outlines its performance measures and its financial plan including net income and costs. The financial plan includes the costs necessary to successfully achieve BC Hydro's performance measures. As the BCUC has oversight into BC Hydro's operating and capital expenditures (which are outlined in Chapter 5 and Chapter 6 of the Application), the BCUC can ask questions to determine whether the costs are reasonable.

This can also be reviewed in light of how BC Hydro measures against its Service Plan metrics to ensure costs reflect the goals of the company. If the BCUC determines that the costs are reasonable and BC Hydro achieves its Service Plan metrics, then the BCUC could conclude that BC Hydro has achieved its performance measures in a cost effective manner.

92.0 Reference: Exhibit B-6, CEC 1.4.1 and 1.4.2

1.4.1 The Comprehensive Review of BC Hydro resulted in a reduction of $2.7 billion from the 10-Year Capital Plan. Which of the above process presents an opportunity for the Commission to assess the success of BC Hydro's capital planning processes as a whole over time, including evaluating BC Hydro's implementation of the 10-Year Capital Plan?

RESPONSE:

The Comprehensive Review of BC Hydro did not drive the reduction of $2.7 billion to the 10-Year Capital Plan. BC Hydro completed an update of the 10-Year Capital Plan and submitted that update as part of the Comprehensive Review.

The success of our capital planning process as a whole over time is best assessed through the information provided in BC Hydro's Service Plan. The Service Plan contains performance measures such as SAIDI, SAIFI and Key Generating Facility Forced Outage Factor which provide an indication of the impact of capital investment on system performance over time. The 2019/20 – 2021/22 Service Plan is provided in Appendix E of the Application and section 6.3.2 of Chapter 6 of the Application provides a discussion of how recent trends in system performance informed the Capital Plan in the Application.

The Integrated Resource Plan process and the Revenue Requirements Application process provide an opportunity for the BCUC to assess BC Hydro's long-term plans and capital planning process, respectively.

RESPONSE:

As explained in BC Hydro's response to CEC IR 1.4.1, BC Hydro completed an update of the 10-Year Capital Plan as part of our capital planning process and this update informed the Comprehensive Review of BC Hydro.

BC Hydro evaluates success in its capital planning through ongoing achievement of Service Plan targets, demonstrating continuous improvements to the capital planning process and its governance, as well as third party evaluation of our asset management practices.

The Service Plan describes BC Hydro's goals, strategies, measures, and targets. BC Hydro management is responsible for measuring performance against these targets, and results are reported to BC Hydro's Board of Directors on a quarterly basis and publicly in the Annual Service Plan Report.

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- System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Forced Outage Factor.
- Quartile ranking based on Hydro-Quebec's Comparison of Electricity Prices in Major North American Cities.

In addition, the achievement of the Safety goal in the Service Plan is also influenced by capital investment strategies.

2.92.3 Please confirm that each electric utility in the different jurisdictions represented by the Electricity Prices in Major North American Cities may have a significantly different cost structures and capabilities in terms of the opportunities they have to manage customer bills.

RESPONSE:

BC Hydro agrees that all electric utilities, including those represented in Hydro-Quebec's Comparison of Electricity Prices in Major North American Cities, may have different cost structures and capabilities in terms of the opportunities they have to manage customer bills.

92.0 Reference: Exhibit B-6, CEC 1.4.1 and 1.4.2

1.4.1 The Comprehensive Review of BC Hydro resulted in a reduction of $2.7 billion from the 10-Year Capital Plan. Which of the above process presents an opportunity for the Commission to assess the success of BC Hydro's capital planning processes as a whole over time, including evaluating BC Hydro's implementation of the 10-Year Capital Plan?

RESPONSE:

The Comprehensive Review of BC Hydro did not drive the reduction of $2.7 billion to the 10-Year Capital Plan. BC Hydro completed an update of the 10-Year Capital Plan and submitted that update as part of the Comprehensive Review.

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The Integrated Resource Plan process and the Revenue Requirements Application process provide an opportunity for the BCUC to assess BC Hydro's long-term plans and capital planning process, respectively.

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- System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Forced Outage Factor.
- Quartile ranking based on Hydro-Quebec's Comparison of Electricity Prices in Major North American Cities.

In addition, the achievement of the Safety goal in the Service Plan is also influenced by capital investment strategies.

2.92.4 Please confirm that measuring improvement over a period of years is a valid methodology to assess performance, providing the measures are normalized.

RESPONSE:

Measuring improvement using normalized results over a period of years would be a valid methodology to assess performance in some, but not all, cases. It would depend on the specific data being assessed.

The Application provides examples where BC Hydro's performance has improved over time:

- **As discussed on page 5-53 of Chapter 5 of the Application, The Brattle Group found that BC Hydro's comparative cost performance has improved over time, mainly due to improvements in cost performance in transmission and distribution;**
- **As discussed on page 6-10 of Chapter 6 of the Application, BC Hydro completed its second Organizational Project Management Maturity Model Assessment in 2016, receiving a score of 91 per cent, which represents a significant increase in maturity from our first assessment in 2010; and**
- **As discussed on page 6-136 of Chapter 6 of the Application, BC Hydro's delivery of Technology capital projects 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.**

92.0 Reference: Exhibit B-6, CEC 1.4.1 and 1.4.2

1.4.1 The Comprehensive Review of BC Hydro resulted in a reduction of $2.7 billion from the 10-Year Capital Plan. Which of the above process presents an opportunity for the Commission to assess the success of BC Hydro's capital planning processes as a whole over time, including evaluating BC Hydro's implementation of the 10-Year Capital Plan?

RESPONSE:

The Comprehensive Review of BC Hydro did not drive the reduction of $2.7 billion to the 10-Year Capital Plan. BC Hydro completed an update of the 10-Year Capital Plan and submitted that update as part of the Comprehensive Review.

The success of our capital planning process as a whole over time is best assessed through the information provided in BC Hydro's Service Plan. The Service Plan contains performance measures such as SAIDI, SAIFI and Key Generating Facility Forced Outage Factor which provide an indication of the impact of capital investment on system performance over time. The 2019/20 – 2021/22 Service Plan is provided in Appendix E of the Application and section 6.3.2 of Chapter 6 of the Application provides a discussion of how recent trends in system performance informed the Capital Plan in the Application.

The Integrated Resource Plan process and the Revenue Requirements Application process provide an opportunity for the BCUC to assess BC Hydro's long-term plans and capital planning process, respectively.

RESPONSE:

As explained in BC Hydro's response to CEC IR 1.4.1, BC Hydro completed an update of the 10-Year Capital Plan as part of our capital planning process and this update informed the Comprehensive Review of BC Hydro.

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- System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Forced Outage Factor.
- Quartile ranking based on Hydro-Quebec's Comparison of Electricity Prices in Major North American Cities.

In addition, the achievement of the Safety goal in the Service Plan is also influenced by capital investment strategies.

2.92.4 Please confirm that measuring improvement over a period of years is a valid methodology to assess performance, providing the measures are normalized.

2.92.4.1 If not confirmed, please explain why not.

RESPONSE:

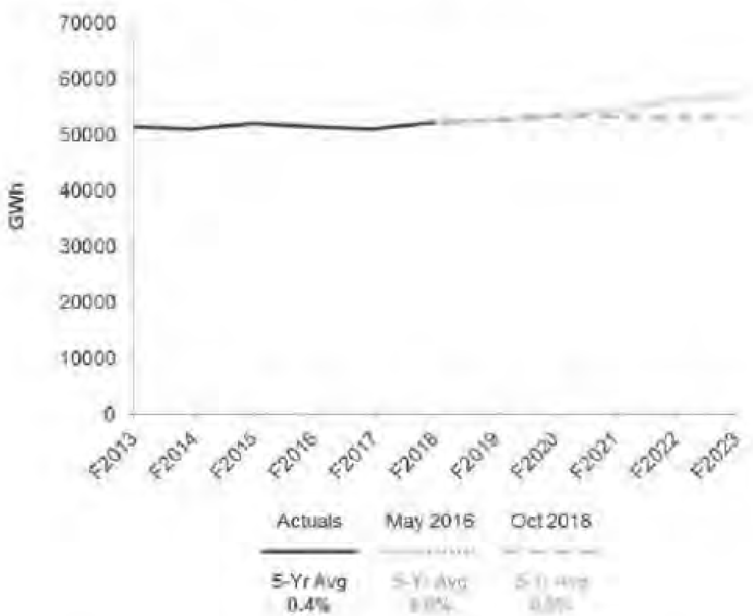
Please refer to BC Hydro's response to CEC IR 2.92.4 where we state that measuring improvement using normalized results over a period of years would be a valid methodology to assess performance in some, but not all, cases.

Commercial Energy Consumers Association of British Columbia Information Request No. **2.93.1** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 2
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit:** **B-13**

93.0 Reference: Exhibit B-6, CEC 1.7.1 and 1.7.4

7.0 Reference: Exhibit B-1, page 3-1

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.

1.7.1 How often does BC Hydro develop its load forecasts?

RESPONSE:

The May 2016 Load Forecast was the last comprehensive forecast update prior to the October 2018 Load Forecast. Historically, BC Hydro has prepared load forecasts on an annual basis and going forward, we anticipate returning to an annual load forecasting cycle.

1.7.4 Please provide any current BC Hydro load growth forecasts that extend beyond 2023. Please provide on the same graph as the May 2016 load growth forecast.

RESPONSE:

The Load Forecast in the Application is for the fiscal 2019 to fiscal 2023 period. BC Hydro's most recent long-term load forecast was the May 2016 Load Forecast, which was provided as part of the Previous Application. BC Hydro is currently developing a new 20-year load forecast and will file that forecast in this proceeding once it is available.

2.93.1 When does BC Hydro expect to provide its next forecast?

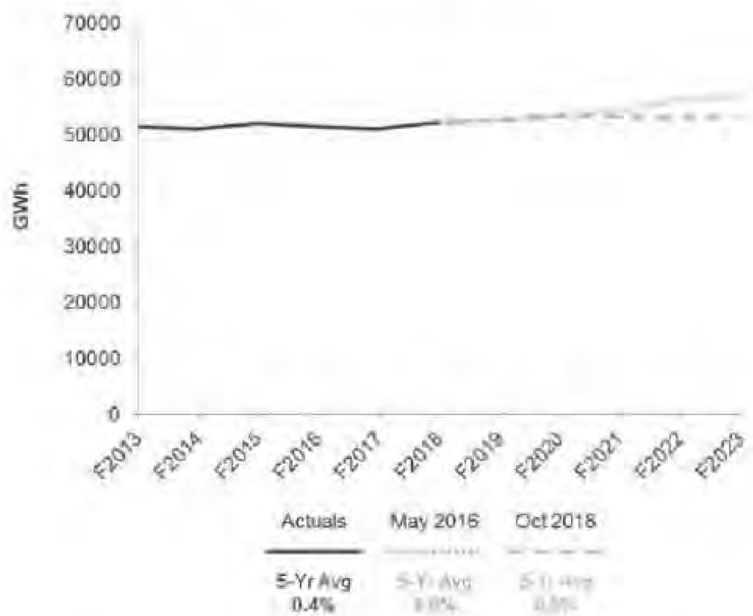
RESPONSE:

BC Hydro will be filing a 20-year load forecast in this proceeding on October 3, 2019 for information purposes. The primary purpose of that forecast is to inform updates to BC Hydro's Service Plan and for internal planning purposes. The next 20-year load forecast is currently being developed for early 2020 to support the 2021 Integrated Resource Plan.

93.0 Reference: Exhibit B-6, CEC 1.7.1 and 1.7.4

7.0 Reference: Exhibit B-1, page 3-1

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.

1.7.1 How often does BC Hydro develop its load forecasts?

RESPONSE:

The May 2016 Load Forecast was the last comprehensive forecast update prior to the October 2018 Load Forecast. Historically, BC Hydro has prepared load forecasts on an annual basis and going forward, we anticipate returning to an annual load forecasting cycle.

1.7.4 Please provide any current BC Hydro load growth forecasts that extend beyond 2023. Please provide on the same graph as the May 2016 load growth forecast.

RESPONSE:

The Load Forecast in the Application is for the fiscal 2019 to fiscal 2023 period. BC Hydro's most recent long-term load forecast was the May 2016 Load Forecast, which was provided as part of the Previous Application. BC Hydro is currently developing a new 20-year load forecast and will file that forecast in this proceeding once it is available.

2.93.2 In the application (Appendix O, page 28), BC Hydro anticipates growth of 23,367 accounts between fiscal 2018 and fiscal 2019 in the Alternative forecast, while BC Hydro's projection is for 28,202 accounts growth for the same period. Please update BC Hydro's projected growth for the period between fiscal 2018 and fiscal 2019.

RESPONSE:

BC Hydro now has the actual number of accounts for fiscal 2019.The actual number of residential accounts for fiscal 2019 was 1,833,097, compared to the forecast number of 1,831,954, for a variance of 1,143 accounts or 0.1 per cent. The difference between fiscal 2018 actual and fiscal 2019 actual is 29,345 accounts. The variance in accounts would have been greater if the alternative forecast based on the FortisBC Electric short-term method was used.

Commercial Energy Consumers Association of British Columbia Information Request No. **2.94.1** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

94.0 Reference: Exhibit B-6, CEC 1.10.1

1.10.1 Please provide the number of years of data BC Hydro used to compare the results of the two methodologies.

RESPONSE:

The number of years used to develop a forecast using BC Hydro data and the FortisBC Electric forecasting method to compare to the May 2016 forecast varies by sector.

For the residential sector, the analysis involved a short-term trend analysis of the average use per account over a three-year period ending fiscal 2015 and regression of accounts and population over a five-year period ending fiscal 2015.

For the commercial sector the linear regression of commercial sales and employment was based on a 10-year period ending fiscal-2015.

2.94.1 Please explain why BC Hydro used short-term trend analysis over a 3-year period for average use per account as opposed to some other period such as 5 or 10 years.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.94.5.

94.0 Reference: Exhibit B-6, CEC 1.10.1

1.10.1 Please provide the number of years of data BC Hydro used to compare the results of the two methodologies.

RESPONSE:

The number of years used to develop a forecast using BC Hydro data and the FortisBC Electric forecasting method to compare to the May 2016 forecast varies by sector.

For the residential sector, the analysis involved a short-term trend analysis of the average use per account over a three-year period ending fiscal 2015 and regression of accounts and population over a five-year period ending fiscal 2015.

For the commercial sector the linear regression of commercial sales and employment was based on a 10-year period ending fiscal-2015.

2.94.2 Please explain why BC Hydro used a 5-year period for the regression of accounts and population as opposed to some other period such as 3 or 10 years.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.94.5.

94.0 Reference: Exhibit B-6, CEC 1.10.1

1.10.1 Please provide the number of years of data BC Hydro used to compare the results of the two methodologies.

RESPONSE:

The number of years used to develop a forecast using BC Hydro data and the FortisBC Electric forecasting method to compare to the May 2016 forecast varies by sector.

For the residential sector, the analysis involved a short-term trend analysis of the average use per account over a three-year period ending fiscal 2015 and regression of accounts and population over a five-year period ending fiscal 2015.

For the commercial sector the linear regression of commercial sales and employment was based on a 10-year period ending fiscal-2015.

2.94.3 Please explain why BC Hydro used a 10-year linear regression for commercial sales and employment vs some other period.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.94.5.

94.0 Reference: Exhibit B-6, CEC 1.10.1

1.10.1 Please provide the number of years of data BC Hydro used to compare the results of the two methodologies.

RESPONSE:

The number of years used to develop a forecast using BC Hydro data and the FortisBC Electric forecasting method to compare to the May 2016 forecast varies by sector.

For the residential sector, the analysis involved a short-term trend analysis of the average use per account over a three-year period ending fiscal 2015 and regression of accounts and population over a five-year period ending fiscal 2015.

For the commercial sector the linear regression of commercial sales and employment was based on a 10-year period ending fiscal-2015.

2.94.4 Did BC Hydro change the periods of linear regression for the differing commercial rate classes? Please explain.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.94.5.

94.0 Reference: Exhibit B-6, CEC 1.10.1

1.10.1 Please provide the number of years of data BC Hydro used to compare the results of the two methodologies.

RESPONSE:

The number of years used to develop a forecast using BC Hydro data and the FortisBC Electric forecasting method to compare to the May 2016 forecast varies by sector.

For the residential sector, the analysis involved a short-term trend analysis of the average use per account over a three-year period ending fiscal 2015 and regression of accounts and population over a five-year period ending fiscal 2015.

For the commercial sector the linear regression of commercial sales and employment was based on a 10-year period ending fiscal-2015.

2.94.5 Please explain why BC Hydro did not utilize consistent periods for its analysis for its residential and commercial accounts.

RESPONSE:

This answer also responds to CEC IRs 2.94.1, 2.94.2 and 2.94.3.

In response to the BCUC's comments on other short-term forecasting methods in its Decision on the Previous Application, we developed an alternative forecast, following the FortisBC Electric method.

The intent in developing the alternative forecast using the FortisBC Electric methodology was to compare the results of our existing forecast methodology to the results obtained by using the FortisBC Electric methodology. For the reasons discussed in section 3.2.11 of Chapter 3 of the Application, we concluded it was appropriate to continue to use our current methodology.

For the residential sector comparative analysis, BC Hydro did not vary the time periods in determining the alternative residential accounts and use per account forecasts because we wanted to maintain consistency with the FortisBC Electric method.

For the commercial sector comparative analysis, BC Hydro had to determine which economic driver best fit BC Hydro's historical commercial sales data. We applied both 10-year and 15-year time periods to various economic drivers and based on this analysis, the 10-year period was determined to have the best fit, as discussed further in section 5.2.2 of Appendix O of the Application.

94.0 Reference: Exhibit B-6, CEC 1.10.1

1.10.1 Please provide the number of years of data BC Hydro used to compare the results of the two methodologies.

RESPONSE:

The number of years used to develop a forecast using BC Hydro data and the FortisBC Electric forecasting method to compare to the May 2016 forecast varies by sector.

For the residential sector, the analysis involved a short-term trend analysis of the average use per account over a three-year period ending fiscal 2015 and regression of accounts and population over a five-year period ending fiscal 2015.

For the commercial sector the linear regression of commercial sales and employment was based on a 10-year period ending fiscal-2015.

2.94.6 Please provide the data for the forecasts using consistent period in the analysis for 3, 5 and 10 years.

RESPONSE:

BC Hydro interprets the question as asking us to provide alternative forecasts, using FortisBC Electric's methodology, where the alternative forecasts are developed with a consistent time frame for residential and commercial sectors. For the alternative forecasts for the commercial sector, BC Hydro interprets the requested analysis to be based on employment as the economic driver, based on the information in the preamble to the question.

The alternative forecasts for the residential and commercial sectors after Demand-Side Management (DSM) savings and loss reduction savings are summarized below. The summary also shows the model statistics used to develop the alternative forecasts for both sectors.

Commercial Sector Summary

Table 1 below shows the calibration history, alternative commercial forecasts, and the October 2018 commercial Load Forecast where all forecasts are after DSM savings and loss reductions savings. Table 2 below shows a summary of the model statistics that were used to develop the alterative forecasts.

Table 1 History and Forecasts

		A Commercial Forecast with Employment after DSM and Rates	B Commercial Forecast with Employment after DSM and Rates	C Commercial Forecast with Employment after DSM and Rates	D BC Hydro Commercial Forecast October 2018 Load Forecast after DSM and Rates
Calibration Period		10	5	3	10
		GWh	GWh	GWh	GWh
Temperature Normalized Actual	F2009	14,374			14,374
Temperature Normalized Actual	F2010	14,237			14,237
Temperature Normalized Actual	F2011	14,492			14,492
Temperature Normalized Actual	F2012	14,380			14,380
Temperature Normalized Actual	F2013	14,333			14,333
Temperature Normalized Actual	F2014	14,343	14,343		14,343
Temperature Normalized Actual	F2015	14,460	14,460		14,460
Temperature Normalized Actual	F2016	14,257	14,257	14,257	14,257
Temperature Normalized Actual	F2017	14,582	14,582	14,582	14,582
Temperature Normalized Actual	F2018	14,513	14,513	14,513	14,513
Forecast	F2019	14,488	14,501	14,545	14,568
Forecast	F2020	14,358	14,375	14,436	14,484
Forecast	F2021	14,227	14,249	14,329	14,352
Forecast	F2022	14,104	14,131	14,231	14,244
Forecast	F2023	13,990	14,021	14,137	14,113
Forecast	F2024	13,890	13,924	14,051	14,034
	Annual Compound Growth Rates				
	5 Yr. Forecast	-0.7%	-0.7%	-0.5%	-0.6%

Table 2 Model Statistics

Calibration Period[1]	10 years	5 years	3 Years	10 years[5]
R2[2]	0.34	0.37	0.50	
DW statistic [3]	3.15	3.58	2.99	
p value of constant[4]	0%	0.5%	20.7%	
p-value of employment[4]	7.60%	27.6%	50.3%	

Notes

1. Calibration period is estimation of the models over a historical time period.

2 .R-square statistic indicates the goodness of fit of the models over the calibration (estimation) period

3. The Durbin Watson statistics test for auto-correlation. 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.

4. 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.

5. Forecast of average use per account are developed with BC Hydro's
Statistically Adjusted End Use Model estimated over a 10 year calibration period from F2009 to F2018 with actual sales.
For further details on the model statistics please see section 18 of Appendix O of the Application.
The historical temperature normalized values are shown for comparing growth rates amongst the alternatives and
the October 2018 Load Forecast.

For each requested calibration time period, the alternative forecasts were developed with the following steps:

1. **A linear regression model of historical temperature normalized commercial sales and employment at the total BC Hydro service area level was developed. A separate regression model was developed for three, five and 10-year calibration periods;**
2. **Model projections were developed from each of the regression models by using the Conference Board of Canada June 2018 Economic Forecast of total employment at the total BC Hydro service area level;**
3. **The model projections from step 2 were adjusted (i.e., increased) for Electric Vehicle forecasts and fuel switching forecasts consistent with forecasts used to develop the October 2018 Load Forecast; and**
4. **After these adjustments were applied, the results were modified (i.e., lowered) for rate impacts, loss reductions savings and DSM savings. The latter two forecasts are based on projections from the October 2018 Load Forecast. The rate impacts were based on the same elasticity and bill impact projections used to develop rate impacts for the October 2018 Load Forecast.**

Summary of Commercial Forecasts

BC Hydro clarifies that the alternative forecast developed with a 10-year calibration period as shown in Table 1 above is the same as the alternative forecast contained in Table 5-7 of section 5.4.2 of Appendix O of the Application, except for the forecast for fiscal 2024. The forecast for that year shown in Appendix O is 13,902 GWh; however, the forecast should be 13,890 GWh as shown in Table 1 above.

The model characteristics, as summarized in Table 2 above, show that for each calibration period used to develop the alternative forecast there is not a strong fit between the historical data and employment (i.e., the R-square statistics are low.) In addition, the employment variable used in each of the calibration periods is not statistically significant (i.e., the p-values are high.) The alternative forecasts developed with calibration periods of three years and five years are similar to the alternative forecast developed with a 10-year estimation period as presented in Appendix O. As such, the variation in the calibration period does not significantly change the alternative forecasts relative to the one provided in Appendix O of the Application.

BC Hydro has provided reasons in the Application (Chapter 3 and section 5.4.2 of Appendix O) as to why the October 2018 Load Forecast should be the basis of the load forecast for revenue projections, relative to the alternative forecasts presented. The above results do not alter our conclusion.

Residential Sector

Table 3 below shows the calibration history, alternative residential forecasts, and the October 2018 residential Load Forecast where all forecasts are after DSM savings and loss reductions savings.

Table 3 History and Forecasts

		E	F	G	H	I
		Alternative Residnetial Forecast after DSM and Rates	Alternative Residential Forecast after DSM and Rates	Alternative Residential Forecast after DSM and Rates	Alternative Residential Forecast after DSM and Rates as contained in Appendix O	BC Hydro Residential Forecast October 2018 Load Forecast after DSM and Rates
Caliberation Period		10	5	3	3 year for use per account; 5 year for accounts	10
		GWh	GWh	GWh	GWh	GWh
Temperature Normalized Actual	F2009	17,104				17,104
Temperature Normalized Actual	F2010	17,836				17,836
Temperature Normalized Actual	F2011	17,792				17,792
Temperature Normalized Actual	F2012	17,704				17,704
Temperature Normalized Actual	F2013	17,852				17,852
Temperature Normalized Actual	F2014	17,928	17,928		17,928	17,928
Temperature Normalized Actual	F2015	17,973	17,973		17,973	17,973
Temperature Normalized Actual	F2016	18,019	18,019	18,019	18,019	18,019
Temperature Normalized Actual	F2017	17,952	17,952	17,952	17,952	17,952
Temperature Normalized Actual	F2018	17,997	17,997	17,997	17,997	17,997
Forecast	F2019	18,201	18,035	17,969	17,953	18,198
Forecast	F2020	18,022	17,795	17,690	17,667	18,253
Forecast	F2021	17,816	17,526	17,380	17,351	18,324
Forecast	F2022	17,663	17,308	17,120	17,085	18,411
Forecast	F2023	17,586	17,165	16,934	16,893	18,551
Forecast	F2024	17,548	17,060	16,784	16,737	18,709
	Annual Compound Growth Rates					
	5 Yr. Forecast	-0.5%	-0.9%	-1.2%	-1.3%	0.6%

Table 4 Model Statistics for Esimation of Relationship between Accounts and Population

Calibration Period[1]	10 years	5 years	3 Years	5 year
R2[2]	0.999	0.998	1.000	0.998
DW statistic[3]	1.950	2.07	3.74	2.07
p value of constant[4]	0.00%	1.3%	3.2%	1.3%
p-value of time trend[4]	0.00%	0.00%	0.5%	0.00%

Table 5 Model Statistics for Relationship between Average Use Per Acccount and Time Trend

Calibration Period[1]	10 years	5 years	3 Years	3 Years	10 years[5]
R2[2]	0.905	0.985	0.989	0.989	
DW statistic[3]	1.8	1.9	3.0	3.0	
p value of constant[4]	0.000%	0.0%	0.2%	0.2%	
p-value of time trend[4]	0.002%	0.1%	6.8%	6.8%	

The following notes apply to both tables:

1. Calibration period is estimation of the models over a historical time period.

2 .R-square statistic indicates the goodness of fit of the models over the calibration (estimation) period.

3. The Durbin Watson statistics test for auto-correlation.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.

4. P-values indicate the statistical significance of the independent variable. P-values greater than 5 per cent indicate that the variable is not statistically significant from zero.

5. Forecast of average use per account are developed with BC Hydro's Statistically Adjusted End Use Model estimated over a 10 year calibration period from F2009 to F2018 with actual sales. For further details on the model statistics please see section 18 of Appendix O. Historical temperature normalized values are shown for comparing growth rates amongst the alternatives and the October 2018 Load Forecast,

Table 4 above shows the summary statistics of the alternative forecasting models used to develop the alternative forecasts of residential average use per account and residential accounts.

For each requested calibration time period, the alternative forecasts were developed with the following steps:

1. **A separate linear time trend model using historical temperature normalized average use per account at the BC Hydro total service area level was developed for each of the requested three, five and 10-year calibration periods;**

2. **The model projections of average use per account were developed from the linear time trend model estimated in step 1 and extending the trend over the forecast period;**

3. **To develop the model projections of residential accounts, a linear regression model of historical residential accounts and population was developed for each of the requested three, five and 10-year calibration periods;**

4. **The model projections of accounts were developed from the model in step 3 and substituting into the model over the forecast period the Conference Board of Canada's June 2018 Economic forecast of population at the total BC Hydro service area level;**

5. **Model projections of alternative residential sales were developed by the product of the projections of average use per account from step 2 and accounts from step 4;**

6. **The model projections of sales from step 5 were adjusted (i.e., increased) for Electric Vehicle forecasts and fuel switching forecasts consistent with forecasts used to develop the October 2018 Load Forecast; and**

7. **After these adjustments were applied, the results were modified (i.e., lowered) for rate impacts, loss reductions savings and DSM savings. The latter two forecasts are based on the projections from the October 2018 Load Forecast. The rate impacts were based on the same elasticity and bill impact projections used to develop rate impacts for the October 2018 Load Forecast.**

Summary of Accounts Forecasts

As indicated by the alternative model statistics shown in Table 4, the models used to develop the alternative residential accounts forecast are reasonable because

there is a good fit between historical accounts and population relationship (i.e., high R-squared statistics).

However, all of the alternative forecasts consistently over-estimated the fiscal 2019 actual number of residential accounts. The fiscal 2019 variance in the accounts was 7,878 accounts or 0.4 per cent for the 10-year model, 5,978 accounts or 0.3 per cent for the 5-year model and 4,371 accounts or 0.2 per cent for the 3-year model. Based on BC Hydro's forecast, the variance between forecast and actual accounts in fiscal 2019 was 1,143 or 0.1 per cent.

While each of these variances is small, BC Hydro believes that its accounts forecast methodology, which is a bottom-up approach based on sub-regional projections of housing from Conference Board of Canada, is more reliable than the alternative regression model approach using total population. For further explanation of the differences between BC Hydro's forecasting approach and the alternative methods, please refer to section 4.2.1 of Appendix O of the Application.

Summary of Use per Account and Sales Forecasts

As indicated by the statistics of the alternative models of average use per account shown in Table 5, models with five-year and 10-year calibration periods are more statistically sound than the model estimated with a three-year period because all of the variables are statistically significant. In addition, each of the alternative models has a good fit (i.e., high R-squared values) to the historical data. However, the alternative approach uses a time trend function and does not consider any other variables, such as average efficiency of appliances, which can impact use per account. In contrast, BC Hydro's residential statistically adjusted end use (SAE) models develop an underlying relationship between actual observed average use per account and drivers such as income, household size and average efficiency. For this reason and the other supporting explanations provided in the Application (Section 4.2.3 of Appendix O), the October 2018 Load Forecast is an appropriate basis for estimating future electricity demand and associated revenue forecasts. The above results do not alter our conclusion.

95.0 Reference: Exhibit B-6, CEC 1.12.1

1.12.1 Does BC Hydro have a low forecast?

RESPONSE:

BC Hydro did not prepare an Electric Vehicle (EV) low load forecast as part of the October 2018 Load Forecast. For the purpose of responding to this IR BC Hydro has used its EV model to generate the following table, which shows the low EV load and stock forecast.

EV Load Forecast - Low		
Fiscal Year	EV Stock	EV Load [GWh]
F2019	20,359	56
F2020	26,474	74
F2021	34,509	97
F2022	49,204	132
F2023	72,181	195
F2024	104,185	286

We believe the range of potential future load from EVs is asymmetric. That is, EV growth points to a greater risk that EV load will be higher relative to the mid (or expected) forecast rather than lower. As such, in preparing the October 2018 Load Forecast we only incorporated the mid and upper EV forecast band in our Monte-Carlo uncertainty model.

2.95.1 Please provide the basis for BC Hydro's belief that the range of potential future load from EVs is asymmetric as described.

RESPONSE:

BC Hydro's belief that there is an asymmetrical risk (i.e., there is more upside potential than downside) for future Electric Vehicle (EV) stock and load is based on a number of factors that have occurred since the development of the October 2018 EV forecast, including:

- **The federal government has introduced a new EV incentive program that provides up to a maximum of $5,000 purchase incentive;**
- **The Government of B.C. has committed an additional $41.5 million toward the CEVforBC rebate program for fiscal 2020 and has lowered the maximum price eligibility threshold to $55,000. Please refer to BC Hydro's response to BCUC IR 2.205.1 for additional information on the expected impact of these government programs; and**

- **The Government of B.C. passed Zero-Emission Vehicle (ZEV) legislation as part of its CleanBC plan, which will require all new vehicles sold in B.C. to be electric by 2040.**

In addition, municipalities such as the City of Vancouver have recently adopted policies that seek to increase the number of EV charging facilities throughout the city, which we believe will enable increased uptake of EVs in the future. For further information, please refer to the City of Vancouver's Climate Emergency Response report located at:

https://council.vancouver.ca/20190424/documents/cfsc1.pdf.

96.0 Reference: Exhibit B-6, CEC 1.14.1

1.14.1 Please discuss all the ways in which BC Hydro models uncertainties and/or accounts for 'trends' in climate, such as those related to climate change, in its load forecasting.

RESPONSE:

This answer also responds to: CEC IR 1.14.2, CEC IR 1.14.3, CEC IR 1.42.3.1, CEC IR 1.42.3.2, INCE IR 1.8.2, INCE IR 1.8.3, INCE IR 1.8.4, INCE IR 1.8.24, INCE IR 1.8.25, and WILLIS IR 1.7.1.

The direct input in our residential and commercial models that can account for climate trends is the temperature element which is measured in heating and cooling degree days.

The model forecasts are 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 to BC Hydro's service area. Using a ten-year rolling average reflects current trends relative to longer-term averaging periods. Our Monte Carlo model also reflects uncertainty in the impact of temperature on load through a random simulation of the heating degrees over the past ten years. Further information is provided in section 11.2.6 of Appendix O of the Application.

We assess future climate trend uncertainties by undertaking climate studies to assess the impacts of extreme weather events on future load, hydroelectric generation and system resiliency.

The most recent analysis of the impact of various climate change scenarios on load was provided in our response to BCUC IR 1.4.3.1, filed in the Previous Application. In addition, a discussion of how BC Hydro is assessing climate impacts was provided in the responses to AMPC IR 1.12.2 and CEABC IR 1.10.2 in the Previous Application. All of these materials are provided at this link.

In partnership with the Pacific Climate Impacts Consortium, new climate scenarios have been developed since the Previous Application. However, these scenarios have not yet been analyzed for potential impacts to future load. The Pacific Climate Impacts Consortium is completing an update of the projected hydrologic scenarios for key watersheds in British Columbia which will support assessment of possible future impacts to water supply for hydropower generation.

Based on a preliminary review of the updated climate projections from the Pacific Climate Impacts Consortium, the trends identified in the previous climate change scenario analysis completed in 2013 appear to be continuing. The Pacific Climate Impacts Consortium's results are consistent with the recently published Canada's Changing Climate Report produced by Environment and Climate Change Canada.

In addition, BC Hydro is undertaking a risk assessment of our grid vulnerability to storm events and severe weather as part of our climate change adaptation efforts. For more detailed information, please refer to BC Hydro's response to BCUC IRs 1.131.1 and 1.131.2.

2.96.1 When does BC Hydro expect the update of the projected hydrologic scenarios for key watersheds in BC will be completed?

RESPONSE:

BC Hydro expects to have the last of the projected hydrologic scenarios for key watersheds available in the fall of 2019.

96.0 Reference: Exhibit B-6, CEC 1.14.1

1.14.1 Please discuss all the ways in which BC Hydro models uncertainties and/or accounts for 'trends' in climate, such as those related to climate change, in its load forecasting.

RESPONSE:

This answer also responds to: CEC IR 1.14.2, CEC IR 1.14.3, CEC IR 1.42.3.1, CEC IR 1.42.3.2, INCE IR 1.8.2, INCE IR 1.8.3, INCE IR 1.8.4, INCE IR 1.8.24, INCE IR 1.8.25, and WILLIS IR 1.7.1.

The direct input in our residential and commercial models that can account for climate trends is the temperature element which is measured in heating and cooling degree days.

The model forecasts are 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 to BC Hydro's service area. Using a ten-year rolling average reflects current trends relative to longer-term averaging periods. Our Monte Carlo model also reflects uncertainty in the impact of temperature on load through a random simulation of the heating degrees over the past ten years. Further information is provided in section 11.2.6 of Appendix O of the Application.

We assess future climate trend uncertainties by undertaking climate studies to assess the impacts of extreme weather events on future load, hydroelectric generation and system resiliency.

The most recent analysis of the impact of various climate change scenarios on load was provided in our response to BCUC IR 1.4.3.1, filed in the Previous Application. In addition, a discussion of how BC Hydro is assessing climate impacts was provided in the responses to AMPC IR 1.12.2 and CEABC IR 1.10.2 in the Previous Application. All of these materials are provided at this link.

In partnership with the Pacific Climate Impacts Consortium, new climate scenarios have been developed since the Previous Application. However, these scenarios have not yet been analyzed for potential impacts to future load. The Pacific Climate Impacts Consortium is completing an update of the projected hydrologic scenarios for key watersheds in British Columbia which will support assessment of possible future impacts to water supply for hydropower generation.

Based on a preliminary review of the updated climate projections from the Pacific Climate Impacts Consortium, the trends identified in the previous climate change scenario analysis completed in 2013 appear to be continuing. The Pacific Climate Impacts Consortium's results are consistent with the recently published Canada's Changing Climate Report produced by Environment and Climate Change Canada.

In addition, BC Hydro is undertaking a risk assessment of our grid vulnerability to storm events and severe weather as part of our climate change adaptation efforts. For more detailed information, please refer to BC Hydro's response to BCUC IRs 1.131.1 and 1.131.2.

2.96.2 Please provide a brief review of the trends identified in the previous climate change scenario analysis and Canada's Changing Climate Report.

RESPONSE:

The key temperature trends from the 2013 climate change scenario analysis were captured in a summary brochure (available at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/environment-sustainability/environmental-reports/potential-impacts-climate-change-on-bchydro-managed-water-resources.pdf) and can be summarized as follows:

- **Over the last century, all regions of British Columbia became warmer by an average of about 1.2°C;**
- **Projected warming in the twenty-first century shows a continuation of patterns similar to those observed in recent decades;**
- **All emission scenarios project increasing temperatures in all seasons in all regions of British Columbia; and**
- **The amount of warming in the twenty-first century will very likely be larger than that of the twentieth century.**

The key temperature trends highlighted in the Government of Canada's "Canada's Changing Climate Report" (available at: https://www.nrcan.gc.ca/maps-tools-and-publications/publications/climate-change-publications/canada-changing-climate-reports/canadas-changing-climate-report/21177) are as follows:

- **Both past and future warming in Canada is, on average, about double the magnitude of global warming;**
- **The effects of widespread warming are evident in many parts of Canada and are projected to intensify in the future; and**
- **A warmer climate will intensify some weather extremes in the future.**

97.0 Reference: Exhibit B-6, CEC 1.16.2

16.0 Reference: Exhibit B-1, page 4-15

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.

1.16.2 Please provide the expected average price for market sales BC Hydro expects Powerex to achieve for BC Hydro for the next three years.

RESPONSE:

Row 21 of Schedule 4.0 on page 38 in Appendix A to the Application shows the expected average price of BC Hydro's Surplus Sales for the next two years to be 40.30 and 36.10 $CAD/MWh for fiscal 2020 and 2021 respectively. The third year is outside of the test period.

2.97.1 How far in advance does Powerex sell energy, and please explain why?

RESPONSE:

BC Hydro sells energy to Powerex pursuant to the Transfer Pricing Agreement. The determination of whether a sale by BC Hydro is allocated to Surplus Sales or Net Purchases (Sales) from Powerex occurs on a day to day basis based on the relevant daily Mid-C Index price and the Threshold Sale Price specified by BC Hydro.

Details of Powerex's business activities, unless otherwise publicly reported are commercially sensitive and thus confidential.

97.0 Reference: Exhibit B-6, CEC 1.16.2

16.0 Reference: Exhibit B-1, page 4-15

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.

1.16.2 Please provide the expected average price for market sales BC Hydro expects Powerex to achieve for BC Hydro for the next three years.

RESPONSE:

Row 21 of Schedule 4.0 on page 38 in Appendix A to the Application shows the expected average price of BC Hydro's Surplus Sales for the next two years to be 40.30 and 36.10 $CAD/MWh for fiscal 2020 and 2021 respectively. The third year is outside of the test period.

2.97.1.1 Please provide the total for Powerex Sales in the last 5 years and % of these sales for each of a relevant set of time periods definitions in advance of the delivery.

RESPONSE:

Data related to BC Hydro's historical sales and purchases with Powerex is provided in Attachment 1 to BC Hydro's response to CEABC IR 2.43.1.

BC Hydro is not able to provide "% of these sales for each of a relevant set of time periods definitions in advance of the delivery" as details of Powerex's business activities, unless otherwise publicly reported are commercially sensitive and thus confidential.

As discussed in BC Hydro's response to CEC IR 2.97.1, BC Hydro sells to Powerex on a day-to-day basis based on the relevant daily Mid-C Index price and the Threshold Sale Price specified by BC Hydro.

98.0 Reference: Exhibit B-6, CEC 1.20.1

RESPONSE:

BC Hydro provides the following modified versions of Table 4-12 and Table 4-13 from the Application which have been extended to include the forecast from fiscal 2022 to fiscal 2031. BC Hydro notes that the amounts for accounting adjustments and two energy supply contracts[1] have not been included in fiscal 2022 to fiscal 2031 because we have not developed a forecast for this entire term.

Modified Table 4-12 IPP and Long-Term Purchase Volumes for the Integrated System, Extended with Forecast for F2022 to F2031 (October 2018 Forecast)

Call Process (GWh)	EPAs	F17 RRA	F17 Actual	F18 RRA	F18 Actual	F19 RRA	F19 Forecast	F2020 Plan	F2021 Plan	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Pre-2003 Electricity Purchase Agreements	31	3,307	3,498	3,350	3,315	3,139	3,289	3,301	3,350	3,344	3,345	3,430	3,368	3,335	3,314	3,290	3,255	3,136	3,137
2003 Green Power Generation Call	6	562	591	562	557	562	565	566	566	566	566	566	566	564	560	560	560	560	560
2006 Open Call	17	2,129	2,235	2,135	2,132	2,135	2,136	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178
2008 Bioenergy Call - Phase 1	2	188	199	188	191	188	161	204	216	198	198	198	198	198	198	198	198	149	109
2008/10 Standing Offer Program	26	295	293	431	338	517	407	486	522	522	522	522	522	522	522	522	522	522	522
2010 Bioenergy Call - Phase 2	4	282	151	725	209	725	568	680	680	680	680	680	686	705	705	705	705	705	705
2010 Clean Power Call	20	1,818	1,649	2,705	2,414	2,863	2,647	2,779	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867
2010 Integrated Power Offer	7	1,022	1,040	1,064	1,012	1,074	1,052	1,175	1,145	1,120	1,134	1,134	1,134	1,134	1,134	1,134	1,122	1,132	1,058
Negotiated Electricity Purchase Agreements[1]	14	3,700	3,989	3,712	4,185	3,703	3,801	4,010	4,369	4,519	4,473	4,484	4,484	4,484	4,484	4,484	4,484	4,388	4,361
Expected Standing Offer Program Projects	7	71	-	130	-	291	6	70	149	230	230	230	230	230	230	230	230	230	230
Total	134	13,375	13,644	15,002	14,354	15,199	14,631	15,449	16,040	16,222	16,191	16,287	16,232	16,216	16,191	16,166	16,120	15,867	15,727

1. The Surplus Power Rights Agreement is not included in fiscal 2022 to fiscal 2031.

Modified Table 4-13 Breakdown of IPP and Long-Term Commitments for the Integrated System, Extended with Forecast for F2022 to F2031 (October 2018 Forecast)

Call Process ($millions)	EPAs	F17 RRA	F17 Actual	F18 RRA	F18 Actual	F19 RRA	F19 Forecast	F2020 Plan	F2021 Plan	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Pre-2003 Electricity Purchase Agreements	31	277.2	287.3	281.0	276.1	261.6	261.9	268.5	276.3	280.0	269.0	282.9	307.3	310.6	313.7	318.1	323.1	318.6	324.3
2003 Green Power Generation Call	6	33.3	34.9	33.7	32.9	34.1	34.0	34.6	35.0	35.4	35.9	36.3	36.7	36.9	37.1	37.8	43.2	44.6	45.7
2006 Open Call	17	188.4	187.5	190.8	187.2	192.7	184.5	196.9	199.0	201.2	203.3	205.9	208.4	210.7	213.0	215.4	217.1	216.5	213.8
2008 Bioenergy Call - Phase 1	2	22.7	22.0	23.0	25.0	23.3	21.7	24.4	20.1	17.5	17.9	18.2	18.6	19.0	19.4	19.7	20.1	15.4	11.4
2008/10 Standing Offer Program	26	28.9	28.2	43.8	33.2	52.6	41.8	50.5	54.4	55.0	55.6	56.2	56.8	57.4	58.1	58.8	59.4	60.0	60.7
2010 Bioenergy Call - Phase 2	4	39.2	20.2	99.7	29.6	100.9	83.0	98.3	99.6	100.9	102.2	103.5	105.9	110.1	111.5	113.0	114.5	116.0	117.5
2010 Clean Power Call	20	242.0	213.0	336.0	296.4	358.3	318.6	353.7	367.6	371.0	374.7	378.6	382.3	386.7	390.9	395.4	399.8	404.4	409.1
2010 Integrated Power Offer	7	126.5	128.4	131.2	127.1	135.1	138.0	156.9	149.8	140.2	140.9	143.7	146.6	149.5	152.5	155.6	148.7	149.6	141.8
Negotiated Electricity Purchase Agreements[1]	14	346.5	353.2	357.1	374.2	359.9	349.9	381.2	416.0	432.0	436.4	445.1	449.5	459.2	467.8	476.7	485.3	485.5	490.9
Expected Standing Offer Program Projects	7	7.8	-	13.6	-	29.2	0.7	8.1	16.4	25.4	25.7	25.9	26.2	26.4	26.7	27.0	27.2	27.5	27.8
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	1,658.7	1,661.4	1,696.3	1,738.3	1,766.5	1,790.7	1,817.4	1,838.5	1,838.2	1,843.0
Accounting Adjustments	n/a	(78.1)	(61.6)	(140.2)	(70.1)	(108.6)	(107.8)	(34.7)	(33.2)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
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	1,658.7	1,661.4	1,696.3	1,738.3	1,766.5	1,790.7	1,817.4	1,838.5	1,838.2	1,843.0

1 The Surplus Power Rights Agreement and the Residual Capacity Agreement are not included in fiscal 2022 to fiscal 2031

2.98.1 Please explain the F2019 forecast variation from the RRA in the 2008/2010 standing offer program costs.

[1] **The two energy supply contracts, Surplus Power Rights Agreement and the Residual Capacity Agreement, included in the "Negotiated EPA" category, as further described in BC Hydro's response to CEABC IR 1.20.1.**

RESPONSE:

The cost and energy values for the fiscal 2019 Forecast are lower than the F2019 RRA Plan primarily as a result of the following factors:

- **One EPA included in the F2019 RRA Plan was terminated prior to the project reaching commercial operations; and**
- **Five projects that were expected to reach operations prior to or during fiscal 2019 did not achieve commercial operations by the dates projected in the F2019 RRA Plan.**

BC Hydro notes that one EPA (Lorenzetta) was signed and reached commercial operations after the finalization of the IPP forecast that was used for the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application filing[1] and before the start of fiscal 2019 resulting in additional costs that partially offset the reductions stated above. As discussed in BC Hydro's response to AMPC IR 1.13.1, once an Standing Offer Program EPA is executed, the volumes associated with the EPA are allocated as a new EPA addition under the "2008/2010 Standing Offer Program" category and removed from the "Expected Standing Offer Program Projects" category.

Please also refer to BC Hydro's response to BCUC IR 1.15.2 for a description of BC Hydro's IPP forecast methodology.

[1] **The IPP forecast that was used for the F2017-F2019 RRA was finalized on May 1, 2016.**

98.0 Reference: Exhibit B-6, CEC 1.20.1

RESPONSE:

BC Hydro provides the following modified versions of Table 4-12 and Table 4-13 from the Application which have been extended to include the forecast from fiscal 2022 to fiscal 2031. BC Hydro notes that the amounts for accounting adjustments and two energy supply contracts[1] have not been included in fiscal 2022 to fiscal 2031 because we have not developed a forecast for this entire term.

[1] **The two energy supply contracts, Surplus Power Rights Agreement and the Residual Capacity Agreement, included in the "Negotiated EPA" category, as further described in BC Hydro's response to CEABC IR 1.20.1.**

Modified Table 4-12 IPP and Long-Term Purchase Volumes for the Integrated System, Extended with Forecast for F2022 to F2031 (October 2018 Forecast)

Call Process (GWh)	EPAs	F17 RRA	F17 Actual	F18 RRA	F18 Actual	F19 RRA	F19 Forecast	F2020 Plan	F2021 Plan	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Pre-2003 Electricity Purchase Agreements	31	3,307	3,498	3,350	3,315	3,139	3,289	3,301	3,350	3,344	3,345	3,430	3,368	3,335	3,314	3,290	3,255	3,136	3,137
2003 Green Power Generation Call	6	562	591	562	557	562	565	566	566	566	566	566	566	564	560	560	560	560	560
2006 Open Call	17	2,129	2,235	2,135	2,132	2,135	2,136	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178
2008 Bioenergy Call - Phase 1	2	188	199	188	191	188	161	204	216	198	198	198	198	198	198	198	198	149	109
2008/10 Standing Offer Program	26	295	293	431	338	517	407	486	522	522	522	522	522	522	522	522	522	522	522
2010 Bioenergy Call - Phase 2	4	282	151	725	209	725	568	680	680	680	680	680	686	705	705	705	705	705	705
2010 Clean Power Call	20	1,818	1,649	2,705	2,414	2,863	2,647	2,779	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867
2010 Integrated Power Offer	7	1,022	1,040	1,064	1,012	1,074	1,052	1,175	1,145	1,120	1,134	1,134	1,134	1,134	1,134	1,134	1,122	1,132	1,058
Negotiated Electricity Purchase Agreements[1]	14	3,700	3,989	3,712	4,185	3,703	3,801	4,010	4,369	4,519	4,473	4,484	4,484	4,484	4,484	4,484	4,484	4,388	4,361
Expected Standing Offer Program Projects	7	71	-	130	-	291	6	70	149	230	230	230	230	230	230	230	230	230	230
Total	134	13,375	13,644	15,002	14,354	15,199	14,631	15,449	16,040	16,222	16,191	16,287	16,232	16,216	16,191	16,166	16,120	15,867	15,727

1. The Surplus Power Rights Agreement is not included in fiscal 2022 to fiscal 2031.

Modified Table 4-13 Breakdown of IPP and Long-Term Commitments for the Integrated System, Extended with Forecast for F2022 to F2031 (October 2018 Forecast)

Call Process ($millions)	EPAs	F17 RRA	F17 Actual	F18 RRA	F18 Actual	F19 RRA	F19 Forecast	F2020 Plan	F2021 Plan	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Pre-2003 Electricity Purchase Agreements	31	277.2	287.3	281.0	276.1	261.6	261.9	268.5	276.3	280.0	269.0	282.9	307.3	310.6	313.7	318.1	323.1	318.6	324.3
2003 Green Power Generation Call	6	33.3	34.9	33.7	32.9	34.1	34.0	34.6	35.0	35.4	35.9	36.3	36.7	36.9	37.1	37.8	43.2	44.6	45.7
2006 Open Call	17	188.4	187.5	190.8	187.2	192.7	184.5	196.9	199.0	201.2	203.3	205.9	208.4	210.7	213.0	215.4	217.1	216.5	213.8
2008 Bioenergy Call - Phase 1	2	22.7	22.0	23.0	25.0	23.3	21.7	24.4	20.1	17.5	17.9	18.2	18.6	19.0	19.4	19.7	20.1	15.4	11.4
2008/10 Standing Offer Program	26	28.9	28.2	43.8	33.2	52.6	41.8	50.5	54.4	55.0	55.6	56.2	56.8	57.4	58.1	58.8	59.4	60.0	60.7
2010 Bioenergy Call - Phase 2	4	39.2	20.2	99.7	29.6	100.9	83.0	98.3	99.6	100.9	102.2	103.5	105.9	110.1	111.5	113.0	114.5	116.0	117.5
2010 Clean Power Call	20	242.0	213.0	336.0	296.4	358.3	318.6	353.7	367.6	371.0	374.7	378.6	382.3	386.7	390.9	395.4	399.8	404.4	409.1
2010 Integrated Power Offer	7	126.5	128.4	131.2	127.1	135.1	138.0	156.9	149.8	140.2	140.9	143.7	146.6	149.5	152.5	155.6	148.7	149.6	141.8
Negotiated Electricity Purchase Agreements[1]	14	346.5	353.2	357.1	374.2	359.9	349.9	381.2	416.0	432.0	436.4	445.1	449.5	459.2	467.8	476.7	485.3	485.5	490.9
Expected Standing Offer Program Projects	7	7.8	-	13.6	-	29.2	0.7	8.1	16.4	25.4	25.7	25.9	26.2	26.4	26.7	27.0	27.2	27.5	27.8
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	1,658.7	1,661.4	1,696.3	1,738.3	1,766.5	1,790.7	1,817.4	1,838.5	1,838.2	1,843.0
Accounting Adjustments	n/a	(78.1)	(61.6)	(140.2)	(70.1)	(108.6)	(107.8)	(34.7)	(33.2)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
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	1,658.7	1,661.4	1,696.3	1,738.3	1,766.5	1,790.7	1,817.4	1,838.5	1,838.2	1,843.0

1 The Surplus Power Rights Agreement and the Residual Capacity Agreement are not included in fiscal 2022 to fiscal 2031.

2.98.1.1 Please explain why the 2008/2010 standing offer program costs are expected to increase again in the F2020 plan and beyond.

RESPONSE:

As of October 1, 2018, the forecast costs for EPAs in the 2008/2010 Standing Offer Program (SOP) category (set out in Modified Table 4-13 as provided in BC Hydro's response to CEC IR 1.20.1 above) are increasing in fiscal 2020 and beyond for the following reasons:

- **Five SOP projects were forecast to reach commercial operation prior to or during the Test Period. This causes forecast energy volumes to increase (as shown in Modified Table 4-12) and forecast costs to increase (as shown in Modified Table 4-13) as these projects reach commercial operations and begin deliveries; and**

- **The prices for SOP EPAs are subject to annual price escalation.**

98.0 Reference: Exhibit B-6, CEC 1.20.1

RESPONSE:

BC Hydro provides the following modified versions of Table 4-12 and Table 4-13 from the Application which have been extended to include the forecast from fiscal 2022 to fiscal 2031. BC Hydro notes that the amounts for accounting adjustments and two energy supply contracts[1] have not been included in fiscal 2022 to fiscal 2031 because we have not developed a forecast for this entire term.

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1 **The two energy supply contracts, Surplus Power Rights Agreement and the Residual Capacity Agreement, included in the "Negotiated EPA" category, as further described in BC Hydro's response to CEABC IR 1.20.1.**

Modified Table 4-12 IPP and Long-Term Purchase Volumes for the Integrated System, Extended with Forecast for F2022 to F2031 (October 2018 Forecast)

Call Process (GWh)	EPAs	F17 RRA	F17 Actual	F18 RRA	F18 Actual	F19 RRA	F19 Forecast	F2020 Plan	F2021 Plan	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Pre-2003 Electricity Purchase Agreements	31	3,307	3,498	3,350	3,315	3,139	3,289	3,301	3,350	3,344	3,345	3,430	3,368	3,335	3,314	3,290	3,255	3,136	3,137
2003 Green Power Generation Call	6	562	591	562	557	562	565	566	566	566	566	566	566	564	560	560	560	560	560
2006 Open Call	17	2,129	2,235	2,135	2,132	2,135	2,136	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178
2008 Bioenergy Call - Phase 1	2	188	199	188	191	188	161	204	216	198	198	198	198	198	198	198	198	149	109
2008/10 Standing Offer Program	26	295	293	431	338	517	407	486	522	522	522	522	522	522	522	522	522	522	522
2010 Bioenergy Call - Phase 2	4	282	151	725	209	725	568	680	680	680	680	680	686	705	705	705	705	705	705
2010 Clean Power Call	20	1,818	1,649	2,705	2,414	2,863	2,647	2,779	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867
2010 Integrated Power Offer	7	1,022	1,040	1,064	1,012	1,074	1,052	1,175	1,145	1,120	1,134	1,134	1,134	1,134	1,134	1,134	1,122	1,132	1,058
Negotiated Electricity Purchase Agreements[1]	14	3,700	3,989	3,712	4,185	3,703	3,801	4,010	4,369	4,519	4,473	4,484	4,484	4,484	4,484	4,484	4,484	4,388	4,361
Expected Standing Offer Program Projects	7	71	-	130	-	291	6	70	149	230	230	230	230	230	230	230	230	230	230
Total	134	13,375	13,644	15,002	14,354	15,199	14,631	15,449	16,040	16,222	16,191	16,287	16,232	16,216	16,191	16,166	16,120	15,867	15,727

1. The Surplus Power Rights Agreement is not included in fiscal 2022 to fiscal 2031.

Modified Table 4-13 Breakdown of IPP and Long-Term Commitments for the Integrated System, Extended with Forecast for F2022 to F2031 (October 2018 Forecast)

Call Process ($millions)	EPAs	F17 RRA	F17 Actual	F18 RRA	F18 Actual	F19 RRA	F19 Forecast	F2020 Plan	F2021 Plan	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Pre-2003 Electricity Purchase Agreements	31	277.2	287.3	281.0	276.1	261.6	261.9	268.5	276.3	280.0	269.0	282.9	307.3	310.6	313.7	318.1	323.1	318.6	324.3
2003 Green Power Generation Call	6	33.3	34.9	33.7	32.9	34.1	34.0	34.6	35.0	35.4	35.9	36.3	36.7	36.9	37.1	37.8	43.2	44.6	45.7
2006 Open Call	17	188.4	187.5	190.8	187.2	192.7	184.5	196.9	199.0	201.2	203.3	205.9	208.4	210.7	213.0	215.4	217.1	216.5	213.8
2008 Bioenergy Call - Phase 1	2	22.7	22.0	23.0	25.0	23.3	21.7	24.4	20.1	17.5	17.9	18.2	18.6	19.0	19.4	19.7	20.1	15.4	11.4
2008/10 Standing Offer Program	26	28.9	28.2	43.8	33.2	52.6	41.8	50.5	54.4	55.0	55.6	56.2	56.8	57.4	58.1	58.8	59.4	60.0	60.7
2010 Bioenergy Call - Phase 2	4	39.2	20.2	99.7	29.6	100.9	83.0	98.3	99.6	100.9	102.2	103.5	105.9	110.1	111.5	113.0	114.5	116.0	117.5
2010 Clean Power Call	20	242.0	213.0	336.0	296.4	358.3	318.6	353.7	367.6	371.0	374.7	378.6	382.3	386.7	390.9	395.4	399.8	404.4	409.1
2010 Integrated Power Offer	7	126.5	128.4	131.2	127.1	135.1	138.0	156.9	149.8	140.2	140.9	143.7	146.6	149.5	152.5	155.6	148.7	149.6	141.8
Negotiated Electricity Purchase Agreements[1]	14	346.5	353.2	357.1	374.2	359.9	349.9	381.2	416.0	432.0	436.4	445.1	449.5	459.2	467.8	476.7	485.3	485.5	490.9
Expected Standing Offer Program Projects	7	7.8	-	13.6	-	29.2	0.7	8.1	16.4	25.4	25.7	25.9	26.2	26.4	26.7	27.0	27.2	27.5	27.8
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	1,658.7	1,661.4	1,696.3	1,738.3	1,766.5	1,790.7	1,817.4	1,838.5	1,838.2	1,843.0
Accounting Adjustments	n/a	(78.1)	(61.6)	(140.2)	(70.1)	(108.6)	(107.8)	(34.7)	(33.2)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
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	1,658.7	1,661.4	1,696.3	1,738.3	1,766.5	1,790.7	1,817.4	1,838.5	1,838.2	1,843.0

1. The Surplus Power Rights Agreement and the Residual Capacity Agreement are not included in fiscal 2022 to fiscal 2031.

2.98.2 Please explain the F2019 forecast variation from the RRA in the 2010 Clean Power Call.

RESPONSE:

The cost and energy values for the fiscal 2019 Forecast are lower than the fiscal 2019 RRA primarily due to the following factors:

- **Two projects that were expected to reach commercial operations prior to or during fiscal 2019 did not achieve commercial operations by the dates estimated in the fiscal 2019 RRA;**
- **In fiscal 2019, a number of the hydro projects were experiencing significantly lower inflows compared to historical inflows, which were used to develop the fiscal 2019 RRA; and**
- **BC Hydro has reduced the forecast annual energy amounts for two projects as historical generation has been materially lower than originally estimated.**

Please also refer to BC Hydro's response to BCUC IR 1.15.2 for a description of BC Hydro's IPP forecast methodology.

98.0 Reference: Exhibit B-6, CEC 1.20.1

RESPONSE:

BC Hydro provides the following modified versions of Table 4-12 and Table 4-13 from the Application which have been extended to include the forecast from fiscal 2022 to fiscal 2031. BC Hydro notes that the amounts for accounting adjustments and two energy supply contracts[1] have not been included in fiscal 2022 to fiscal 2031 because we have not developed a forecast for this entire term.

Modified Table 4-12 IPP and Long-Term Purchase Volumes for the Integrated System, Extended with Forecast for F2022 to F2031 (October 2018 Forecast)

Call Process (GWh)	EPAs	F17 RRA	F17 Actual	F18 RRA	F18 Actual	F19 RRA	F19 Forecast	F2020 Plan	F2021 Plan	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Pre-2003 Electricity Purchase Agreements	31	3,307	3,498	3,350	3,315	3,139	3,289	3,301	3,350	3,344	3,345	3,430	3,368	3,335	3,314	3,290	3,255	3,136	3,137
2003 Green Power Generation Call	6	562	591	562	557	562	565	566	566	566	566	566	566	564	560	560	560	560	560
2006 Open Call	17	2,129	2,235	2,135	2,132	2,135	2,136	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178
2008 Bioenergy Call - Phase 1	2	188	199	188	191	188	161	204	216	198	198	198	198	198	198	198	198	149	109
2008/10 Standing Offer Program	26	295	293	431	338	517	407	486	522	522	522	522	522	522	522	522	522	522	522
2010 Bioenergy Call - Phase 2	4	282	151	725	209	725	568	680	680	680	680	680	686	705	705	705	705	705	705
2010 Clean Power Call	20	1,818	1,649	2,705	2,414	2,863	2,647	2,779	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867
2010 Integrated Power Offer	7	1,022	1,040	1,064	1,012	1,074	1,052	1,175	1,145	1,120	1,134	1,134	1,134	1,134	1,134	1,134	1,122	1,132	1,058
Negotiated Electricity Purchase Agreements[1]	14	3,700	3,989	3,712	4,185	3,703	3,801	4,010	4,369	4,519	4,473	4,484	4,484	4,484	4,484	4,484	4,484	4,388	4,361
Expected Standing Offer Program Projects	7	71	-	130	-	291	6	70	149	230	230	230	230	230	230	230	230	230	230
Total	134	13,375	13,644	15,002	14,354	15,199	14,631	15,449	16,040	16,222	16,191	16,287	16,232	16,216	16,191	16,166	16,120	15,867	15,727

1. The Surplus Power Rights Agreement is not included in fiscal 2022 to fiscal 2031.

Modified Table 4-13 Breakdown of IPP and Long-Term Commitments for the Integrated System, Extended with Forecast for F2022 to F2031 (October 2018 Forecast)

Call Process ($millions)	EPAs	F17 RRA	F17 Actual	F18 RRA	F18 Actual	F19 RRA	F19 Forecast	F2020 Plan	F2021 Plan	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Pre-2003 Electricity Purchase Agreements	31	277.2	287.3	281.0	276.1	261.6	261.9	268.5	276.3	280.0	269.0	282.9	307.3	310.6	313.7	318.1	323.1	318.6	324.3
2003 Green Power Generation Call	6	33.3	34.9	33.7	32.9	34.1	34.0	34.6	35.0	35.4	35.9	36.3	36.7	36.9	37.1	37.8	43.2	44.6	45.7
2006 Open Call	17	188.4	187.5	190.8	187.2	192.7	184.5	196.9	199.0	201.2	203.3	205.9	208.4	210.7	213.0	215.4	217.1	216.5	213.8
2008 Bioenergy Call - Phase 1	2	22.7	22.0	23.0	25.0	23.3	21.7	24.4	20.1	17.5	17.9	18.2	18.6	19.0	19.4	19.7	20.1	15.4	11.4
2008/10 Standing Offer Program	26	28.9	28.2	43.8	33.2	52.6	41.8	50.5	54.4	55.0	55.6	56.2	56.8	57.4	58.1	58.8	59.4	60.0	60.7
2010 Bioenergy Call - Phase 2	4	39.2	20.2	99.7	29.6	100.9	83.0	98.3	99.6	100.9	102.2	103.5	105.9	110.1	111.5	113.0	114.5	116.0	117.5
2010 Clean Power Call	20	242.0	213.0	336.0	296.4	358.3	318.6	353.7	367.6	371.0	374.7	378.6	382.3	386.7	390.9	395.4	399.8	404.4	409.1
2010 Integrated Power Offer	7	126.5	128.4	131.2	127.1	135.1	138.0	156.9	149.8	140.2	140.9	143.7	146.6	149.5	152.5	155.6	148.7	149.6	141.8
Negotiated Electricity Purchase Agreements[1]	14	346.5	353.2	357.1	374.2	359.9	349.9	381.2	416.0	432.0	436.4	445.1	449.5	459.2	467.8	476.7	485.3	485.5	490.9
Expected Standing Offer Program Projects	7	7.8	-	13.6	-	29.2	0.7	8.1	16.4	25.4	25.7	25.9	26.2	26.4	26.7	27.0	27.2	27.5	27.8
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	1,658.7	1,661.4	1,696.3	1,738.3	1,766.5	1,790.7	1,817.4	1,838.5	1,838.2	1,843.0
Accounting Adjustments	n/a	(78.1)	(61.6)	(140.2)	(70.1)	(108.6)	(107.8)	(34.7)	(33.2)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
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	1,658.7	1,661.4	1,696.3	1,738.3	1,766.5	1,790.7	1,817.4	1,838.5	1,838.2	1,843.0

1 The Surplus Power Rights Agreement and the Residual Capacity Agreement are not included in fiscal 2022 to fiscal 2031.

2.98.2.1 Please explain why the 2010 Clean Power Call is expected to increase again in the F2020 plan and beyond.

1 **The two energy supply contracts, Surplus Power Rights Agreement and the Residual Capacity Agreement, included in the "Negotiated EPA" category, as further described in BC Hydro's response to CEABC IR 1.20.1.**

RESPONSE:

As of October 1, 2018, the forecast costs for EPAs in the 2010 Clean Power Call category (set out in Modified Table 4-13 above) are increasing in fiscal 2020 and beyond because:

- **Two projects were expected to reach commercial operations prior to or during the Test Period. This causes forecast energy volumes to increase (as shown in Modified Table 4-12) and forecast costs to increase (as shown in Modified Table 4-13) as these projects reach commercial operations and begin deliveries; and**

- **The prices for 2010 Clean Power Call EPAs are subject to annual price escalation.**

98.0 Reference: Exhibit B-6, CEC 1.20.1

RESPONSE:

BC Hydro provides the following modified versions of Table 4-12 and Table 4-13 from the Application which have been extended to include the forecast from fiscal 2022 to fiscal 2031. BC Hydro notes that the amounts for accounting adjustments and two energy supply contracts[1] have not been included in fiscal 2022 to fiscal 2031 because we have not developed a forecast for this entire term.

[1] **The two energy supply contracts, Surplus Power Rights Agreement and the Residual Capacity Agreement, included in the "Negotiated EPA" category, as further described in BC Hydro's response to CEABC IR 1.20.1.**

Modified Table 4-12 IPP and Long-Term Purchase Volumes for the Integrated System, Extended with Forecast for F2022 to F2031 (October 2018 Forecast)

Call Process (GWh)	EPAs	F17 RRA	F17 Actual	F18 RRA	F18 Actual	F19 RRA	F19 Forecast	F2020 Plan	F2021 Plan	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Pre-2003 Electricity Purchase Agreements	31	3,307	3,498	3,350	3,315	3,139	3,289	3,301	3,350	3,344	3,345	3,430	3,368	3,335	3,314	3,290	3,255	3,136	3,137
2003 Green Power Generation Call	6	562	591	562	557	562	565	566	566	566	566	566	566	564	560	560	560	560	560
2006 Open Call	17	2,129	2,235	2,135	2,132	2,135	2,136	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178
2008 Bioenergy Call - Phase 1	2	188	199	188	191	188	161	204	216	198	198	198	198	198	198	198	198	149	109
2008/10 Standing Offer Program	26	295	293	431	338	517	407	486	522	522	522	522	522	522	522	522	522	522	522
2010 Bioenergy Call - Phase 2	4	282	151	725	209	725	568	680	680	680	680	680	686	705	705	705	705	705	705
2010 Clean Power Call	20	1,818	1,649	2,705	2,414	2,863	2,647	2,779	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867
2010 Integrated Power Offer	7	1,022	1,040	1,064	1,012	1,074	1,052	1,175	1,145	1,120	1,134	1,134	1,134	1,134	1,134	1,134	1,122	1,132	1,058
Negotiated Electricity Purchase Agreements[1]	14	3,700	3,989	3,712	4,185	3,703	3,801	4,010	4,369	4,519	4,473	4,484	4,484	4,484	4,484	4,484	4,484	4,388	4,361
Expected Standing Offer Program Projects	7	71	-	130	-	291	6	70	149	230	230	230	230	230	230	230	230	230	230
Total	134	13,375	13,644	15,002	14,354	15,199	14,631	15,449	16,040	16,222	16,191	16,287	16,232	16,216	16,191	16,166	16,120	15,867	15,727

1. The Surplus Power Rights Agreement is not included in fiscal 2022 to fiscal 2031.

Modified Table 4-13 Breakdown of IPP and Long-Term Commitments for the Integrated System, Extended with Forecast for F2022 to F2031 (October 2018 Forecast)

Call Process ($millions)	EPAs	F17 RRA	F17 Actual	F18 RRA	F18 Actual	F19 RRA	F19 Forecast	F2020 Plan	F2021 Plan	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Pre-2003 Electricity Purchase Agreements	31	277.2	287.3	281.0	276.1	261.6	261.9	268.5	276.3	280.0	269.0	282.9	307.3	310.6	313.7	318.1	323.1	318.6	324.3
2003 Green Power Generation Call	6	33.3	34.9	33.7	32.9	34.1	34.0	34.6	35.0	35.4	35.9	36.3	36.7	36.9	37.1	37.8	43.2	44.6	45.7
2006 Open Call	17	188.4	187.5	190.8	187.2	192.7	184.5	196.9	199.0	201.2	203.3	205.9	208.4	210.7	213.0	215.4	217.1	216.5	213.8
2008 Bioenergy Call - Phase 1	2	22.7	22.0	23.0	25.0	23.3	21.7	24.4	20.1	17.5	17.9	18.2	18.6	19.0	19.4	19.7	20.1	15.4	11.4
2008/10 Standing Offer Program	26	28.9	28.2	43.8	33.2	52.6	41.8	50.5	54.4	55.0	55.6	56.2	56.8	57.4	58.1	58.8	59.4	60.0	60.7
2010 Bioenergy Call - Phase 2	4	39.2	20.2	99.7	29.6	100.9	83.0	98.3	99.6	100.9	102.2	103.5	105.9	110.1	111.5	113.0	114.5	116.0	117.5
2010 Clean Power Call	20	242.0	213.0	336.0	296.4	358.3	318.6	353.7	367.6	371.0	374.7	378.6	382.3	386.7	390.9	395.4	399.8	404.4	409.1
2010 Integrated Power Offer	7	126.5	128.4	131.2	127.1	135.1	138.0	156.9	149.8	140.2	140.9	143.7	146.6	149.5	152.5	155.6	148.7	149.6	141.8
Negotiated Electricity Purchase Agreements[1]	14	346.5	353.2	357.1	374.2	359.9	349.9	381.2	416.0	432.0	436.4	445.1	449.5	459.2	467.8	476.7	485.3	485.5	490.9
Expected Standing Offer Program Projects	7	7.8	-	13.6	-	29.2	0.7	8.1	16.4	25.4	25.7	25.9	26.2	26.4	26.7	27.0	27.2	27.5	27.8
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	1,658.7	1,661.4	1,696.3	1,738.3	1,766.5	1,790.7	1,817.4	1,838.5	1,838.2	1,843.0
Accounting Adjustments	n/a	(78.1)	(61.6)	(140.2)	(70.1)	(108.6)	(107.8)	(34.7)	(33.2)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
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	1,658.7	1,661.4	1,696.3	1,738.3	1,766.5	1,790.7	1,817.4	1,838.5	1,838.2	1,843.0

1. The Surplus Power Rights Agreement and the Residual Capacity Agreement are not included in fiscal 2022 to fiscal 2031.

2.98.3 Please explain what is a 'Negotiated Electricity Purchase Agreement' and with whom the parties BC Hydro has negotiated the agreements with.

RESPONSE:

The table below sets out the EPAs included in the "Negotiated Electricity Purchase Agreement" line item of Tables 4-12 and 4-13 of the Application and the parties with whom BC Hydro negotiated the agreements. BC Hydro notes that some agreements may now have a different counterparty.

BC Hydro generally uses the term "negotiated electricity purchase agreement" to describe EPAs that were negotiated on a bilateral basis and which did not go through a competitive call or standing offer. This type of procurement has been used for the renewal of pre-existing EPAs, for opportunities associated with power projects that are already contracted to BC Hydro, and for complex or unique transactions where customized negotiations and contracts were necessary.

However, in terms of what is included under "Negotiated Electricity Purchase Agreement" in Tables 4-12 and 4-13 of the Application, this line represents values for negotiated EPAs that were largely completed since 2003, with one exception[1].

As discussed on page 4-28 of the Application, the volumes associated with negotiated EPA renewals that were originally acquired through a competitive call or standing offer program are included in the total values of the EPA's original procurement process. For example, the Soo River EPA renewal is listed under "Pre-2003 Electricity Purchase Agreements".

EPA	EPA Negotiation Counterparty
Armstrong Wood Waste Co-Gen (RVG)	Tolko Industries Ltd.
Conifex Green Energy	Conifex Power Inc.
Dokie Wind	Dokie Wind Energy Inc.
East Twin Creek Hydro	East Twin Creek Hydro Ltd.
Forrest Kerr Hydroelectric	Coast Mountain Hydro Limited Partnership
Fraser Richmond Soil and Fibre	Fraser Richmond Soil & Fibre Ltd.
Houweling Nurseries (Delta) Cogeneration	Houweling Nurseries Ltd.
Kemano	Alcan Inc.

[1] **The East Twin Creek Hydro EPA was completed prior to 2003.**

EPA	EPA Negotiation Counterparty
McLymont Creek	**Coast Mountain Hydro Limited Partnership**
Seegen 2	**Covanta Burnaby Renewable Energy, ULC**
Silversmith Power & Light	**Silversmith Power & Light Corporation**
Skookumchuck Power Project	**Tembec**
Volcano Creek	**Coast Mountain Hydro Limited Partnership**
Waneta Expansion	**Waneta Expansion Limited Partnership**

98.0 Reference: Exhibit B-6, CEC 1.20.1

RESPONSE:

BC Hydro provides the following modified versions of Table 4-12 and Table 4-13 from the Application which have been extended to include the forecast from fiscal 2022 to fiscal 2031. BC Hydro notes that the amounts for accounting adjustments and two energy supply contracts[1] have not been included in fiscal 2022 to fiscal 2031 because we have not developed a forecast for this entire term.

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[1] **The two energy supply contracts, Surplus Power Rights Agreement and the Residual Capacity Agreement, included in the "Negotiated EPA" category, as further described in BC Hydro's response to CEABC IR 1.20.1.**

Modified Table 4-12 IPP and Long-Term Purchase Volumes for the Integrated System, Extended with Forecast for F2022 to F2031 (October 2018 Forecast)

Call Process (GWh)	EPAs	F17 RRA	F17 Actual	F18 RRA	F18 Actual	F19 RRA	F19 Forecast	F2020 Plan	F2021 Plan	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Pre-2003 Electricity Purchase Agreements	31	3,307	3,498	3,350	3,315	3,139	3,289	3,301	3,350	3,344	3,345	3,430	3,368	3,335	3,314	3,290	3,255	3,136	3,137
2003 Green Power Generation Call	6	562	591	562	557	562	565	566	566	566	566	566	566	564	560	560	560	560	560
2006 Open Call	17	2,129	2,235	2,135	2,132	2,135	2,136	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178
2008 Bioenergy Call - Phase 1	2	188	199	188	191	188	161	204	216	198	198	198	198	198	198	198	198	149	109
2008/10 Standing Offer Program	26	295	293	431	338	517	407	486	522	522	522	522	522	522	522	522	522	522	522
2010 Bioenergy Call - Phase 2	4	282	151	725	209	725	568	680	680	680	680	680	686	705	705	705	705	705	705
2010 Clean Power Call	20	1,818	1,649	2,705	2,414	2,863	2,647	2,779	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867
2010 Integrated Power Offer	7	1,022	1,040	1,064	1,012	1,074	1,052	1,175	1,145	1,120	1,134	1,134	1,134	1,134	1,134	1,134	1,122	1,132	1,058
Negotiated Electricity Purchase Agreements[1]	14	3,700	3,989	3,712	4,185	3,703	3,801	4,010	4,369	4,519	4,473	4,484	4,484	4,484	4,484	4,484	4,484	4,388	4,361
Expected Standing Offer Program Projects	7	71	-	130	-	291	6	70	149	230	230	230	230	230	230	230	230	230	230
Total	134	13,375	13,644	15,002	14,354	15,199	14,631	15,449	16,040	16,222	16,191	16,287	16,232	16,216	16,191	16,166	16,120	15,867	15,727

1. The Surplus Power Rights Agreement is not included in fiscal 2022 to fiscal 2031.

Modified Table 4-13 Breakdown of IPP and Long-Term Commitments for the Integrated System, Extended with Forecast for F2022 to F2031 (October 2018 Forecast)

Call Process ($millions)	EPAs	F17 RRA	F17 Actual	F18 RRA	F18 Actual	F19 RRA	F19 Forecast	F2020 Plan	F2021 Plan	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Pre-2003 Electricity Purchase Agreements	31	277.2	287.3	281.0	276.1	261.6	261.9	268.5	276.3	280.0	269.0	282.9	307.3	310.6	313.7	318.1	323.1	318.6	324.3
2003 Green Power Generation Call	6	33.3	34.9	33.7	32.9	34.1	34.0	34.6	35.0	35.4	35.9	36.3	36.7	36.9	37.1	37.8	43.2	44.6	45.7
2006 Open Call	17	188.4	187.5	190.8	187.2	192.7	184.5	196.9	199.0	201.2	203.3	205.9	208.4	210.7	213.0	215.4	217.1	216.5	213.8
2008 Bioenergy Call - Phase 1	2	22.7	22.0	23.0	25.0	23.3	21.7	24.4	20.1	17.5	17.9	18.2	18.6	19.0	19.4	19.7	20.1	15.4	11.4
2008/10 Standing Offer Program	26	28.9	28.2	43.8	33.2	52.6	41.8	50.5	54.4	55.0	55.6	56.2	56.8	57.4	58.1	58.8	59.4	60.0	60.7
2010 Bioenergy Call - Phase 2	4	39.2	20.2	99.7	29.6	100.9	83.0	98.3	99.6	100.9	102.2	103.5	105.9	110.1	111.5	113.0	114.5	116.0	117.5
2010 Clean Power Call	20	242.0	213.0	336.0	296.4	358.3	318.6	353.7	367.6	371.0	374.7	378.6	382.3	386.7	390.9	395.4	399.8	404.4	409.1
2010 Integrated Power Offer	7	126.5	128.4	131.2	127.1	135.1	138.0	156.9	149.8	140.2	140.9	143.7	146.6	149.5	152.5	155.6	148.7	149.6	141.8
Negotiated Electricity Purchase Agreements[1]	14	346.5	353.2	357.1	374.2	359.9	349.9	381.2	416.0	432.0	436.4	445.1	449.5	459.2	467.8	476.7	485.3	485.5	490.9
Expected Standing Offer Program Projects	7	7.8	-	13.6	-	29.2	0.7	8.1	16.4	25.4	25.7	25.9	26.2	26.4	26.7	27.0	27.2	27.5	27.8
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	1,658.7	1,661.4	1,696.3	1,738.3	1,766.5	1,790.7	1,817.4	1,838.5	1,838.2	1,843.0
Accounting Adjustments	n/a	(78.1)	(61.6)	(140.2)	(70.1)	(108.6)	(107.8)	(34.7)	(33.2)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
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	1,658.7	1,661.4	1,696.3	1,738.3	1,766.5	1,790.7	1,817.4	1,838.5	1,838.2	1,843.0

1. The Surplus Power Rights Agreement and the Residual Capacity Agreement are not included in fiscal 2022 to fiscal 2031.

2.98.4 Please explain the F2019 forecast variation in the Negotiated Electricity Purchase Agreement costs from the 2019 RRA.

RESPONSE:

The public version of the response to this information request has been redacted to maintain confidentiality. The un-redacted version of this response is being made available to the BCUC only, in order to protect IPPs' commercial interests. The public disclosure of the redacted information could also impact BC Hydro's commercial interests and ongoing negotiations related to the EPAs.

The cost of Negotiated Electricity Purchase Agreements for the F2019 Forecast is lower than the F2019 RRA, despite total volumes for this category increasing as shown in Modified Table 4-12. This is largely because volumes for certain higher-priced contracts have reduced, which is only partially offset by an increase in volumes for other lower-priced contracts. Specific changes include:

- **A subset of hydroelectric projects (with generally higher prices) are experiencing overall lower inflows and related energy deliveries than estimated in the F2019 RRA, which was generally based on historical averages;**
- **A subset of hydroelectric projects are delivering more energy than estimated in the F2019 RRA which was generally based on historical averages; however, this increase in deliveries is during the freshet period where contract prices are generally lower;**
- **Biomass plants (with generally lower prices) have delivered more energy than estimated in the F2019 RRA; and**

[redacted]

In addition, the Conifex Mackenzie EPA (related to a combined heat and power facility), which had been expected to reach commercial operations in fiscal 2018 in the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, was terminated prior to the project reaching commercial operations.

Please refer to BC Hydro's response to BCUC IR 1.15.2 for a description of BC Hydro's IPP forecast methodology.

98.0 Reference: Exhibit B-6, CEC 1.20.1

RESPONSE:

BC Hydro provides the following modified versions of Table 4-12 and Table 4-13 from the Application which have been extended to include the forecast from fiscal 2022 to fiscal 2031. BC Hydro notes that the amounts for accounting adjustments and two energy supply contracts[1] have not been included in fiscal 2022 to fiscal 2031 because we have not developed a forecast for this entire term.

[1] **The two energy supply contracts, Surplus Power Rights Agreement and the Residual Capacity Agreement, included in the "Negotiated EPA" category, as further described in BC Hydro's response to CEABC IR 1.20.1.**

Modified Table 4-12 IPP and Long-Term Purchase Volumes for the Integrated System, Extended with Forecast for F2022 to F2031 (October 2018 Forecast)

Call Process (GWh)	EPAs	F17 RRA	F17 Actual	F18 RRA	F18 Actual	F19 RRA	F19 Forecast	F2020 Plan	F2021 Plan	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Pre-2003 Electricity Purchase Agreements	31	3,307	3,498	3,350	3,315	3,139	3,289	3,301	3,350	3,344	3,345	3,430	3,368	3,335	3,314	3,290	3,255	3,136	3,137
2003 Green Power Generation Call	6	562	591	562	557	562	565	566	566	566	566	566	566	564	560	560	560	560	560
2006 Open Call	17	2,129	2,235	2,135	2,132	2,135	2,136	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178
2008 Bioenergy Call - Phase 1	2	188	199	188	191	188	161	204	216	198	198	198	198	198	198	198	198	149	109
2008/10 Standing Offer Program	26	295	293	431	338	517	407	486	522	522	522	522	522	522	522	522	522	522	522
2010 Bioenergy Call - Phase 2	4	282	151	725	209	725	568	680	680	680	680	680	686	705	705	705	705	705	705
2010 Clean Power Call	20	1,818	1,649	2,705	2,414	2,863	2,647	2,779	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867
2010 Integrated Power Offer	7	1,022	1,040	1,064	1,012	1,074	1,052	1,175	1,145	1,120	1,134	1,134	1,134	1,134	1,134	1,134	1,122	1,132	1,058
Negotiated Electricity Purchase Agreements[1]	14	3,700	3,989	3,712	4,185	3,703	3,801	4,010	4,369	4,519	4,473	4,484	4,484	4,484	4,484	4,484	4,484	4,388	4,361
Expected Standing Offer Program Projects	7	71	-	130	-	291	6	70	149	230	230	230	230	230	230	230	230	230	230
Total	134	13,375	13,644	15,002	14,354	15,199	14,631	15,449	16,040	16,222	16,191	16,287	16,232	16,216	16,191	16,166	16,120	15,867	15,727

1. The Surplus Power Rights Agreement is not included in fiscal 2022 to fiscal 2031.

Modified Table 4-13 Breakdown of IPP and Long-Term Commitments for the Integrated System, Extended with Forecast for F2022 to F2031 (October 2018 Forecast)

Call Process ($millions)	EPAs	F17 RRA	F17 Actual	F18 RRA	F18 Actual	F19 RRA	F19 Forecast	F2020 Plan	F2021 Plan	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Pre-2003 Electricity Purchase Agreements	31	277.2	287.3	281.0	276.1	261.6	261.9	268.5	276.3	280.0	269.0	282.9	307.3	310.6	313.7	318.1	323.1	318.6	324.3
2003 Green Power Generation Call	6	33.3	34.9	33.7	32.9	34.1	34.0	34.6	35.0	35.4	35.9	36.3	36.7	36.9	37.1	37.8	43.2	44.6	45.7
2006 Open Call	17	188.4	187.5	190.8	187.2	192.7	184.5	196.9	199.0	201.2	203.3	205.9	208.4	210.7	213.0	215.4	217.1	216.5	213.8
2008 Bioenergy Call - Phase 1	2	22.7	22.0	23.0	25.0	23.3	21.7	24.4	20.1	17.5	17.9	18.2	18.6	19.0	19.4	19.7	20.1	15.4	11.4
2008/10 Standing Offer Program	26	28.9	28.2	43.8	33.2	52.6	41.8	50.5	54.4	55.0	55.6	56.2	56.8	57.4	58.1	58.8	59.4	60.0	60.7
2010 Bioenergy Call - Phase 2	4	39.2	20.2	99.7	29.6	100.9	83.0	98.3	99.6	100.9	102.2	103.5	105.9	110.1	111.5	113.0	114.5	116.0	117.5
2010 Clean Power Call	20	242.0	213.0	336.0	296.4	358.3	318.6	353.7	367.6	371.0	374.7	378.6	382.3	386.7	390.9	395.4	399.8	404.4	409.1
2010 Integrated Power Offer	7	126.5	128.4	131.2	127.1	135.1	138.0	156.9	149.8	140.2	140.9	143.7	146.6	149.5	152.5	155.6	148.7	149.6	141.8
Negotiated Electricity Purchase Agreements[1]	14	346.5	353.2	357.1	374.2	359.9	349.9	381.2	416.0	432.0	436.4	445.1	449.5	459.2	467.8	476.7	485.3	485.5	490.9
Expected Standing Offer Program Projects	7	7.8	-	13.6	-	29.2	0.7	8.1	16.4	25.4	25.7	25.9	26.2	26.4	26.7	27.0	27.2	27.5	27.8
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	1,658.7	1,661.4	1,696.3	1,738.3	1,766.5	1,790.7	1,817.4	1,838.5	1,838.2	1,843.0
Accounting Adjustments	n/a	(78.1)	(61.6)	(140.2)	(70.1)	(108.6)	(107.8)	(34.7)	(33.2)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
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	1,658.7	1,661.4	1,696.3	1,738.3	1,766.5	1,790.7	1,817.4	1,838.5	1,838.2	1,843.0

1. The Surplus Power Rights Agreement and the Residual Capacity Agreement are not included in fiscal 2022 to fiscal 2031.

2.98.5 Please explain why the Negotiated Electricity Purchase Agreement costs are expected to increase again in the F2020 plan and beyond.

RESPONSE:

As of October 1, 2018, the forecast costs for EPAs in the Negotiated Electricity Purchase Agreement category (set out in Modified Table 4-13 above) are increasing in fiscal 2020 and beyond generally for the following reasons:

- **Additional energy is expected to be delivered by Rio Tinto Alcan after completion of the second tunnel at Kemano. Please refer to BC Hydro's response to CEABC IR 2.31.1 for discussion of the expected capacity and energy increase from the second tunnel; and**
- **The prices for the Negotiated Electricity Purchase Agreements are subject to annual price escalation.**

98.0 Reference: Exhibit B-6, CEC 1.20.1

RESPONSE:

BC Hydro provides the following modified versions of Table 4-12 and Table 4-13 from the Application which have been extended to include the forecast from fiscal 2022 to fiscal 2031. BC Hydro notes that the amounts for accounting adjustments and two energy supply contracts[1] have not been included in fiscal 2022 to fiscal 2031 because we have not developed a forecast for this entire term.

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[1] **The two energy supply contracts, Surplus Power Rights Agreement and the Residual Capacity Agreement, included in the "Negotiated EPA" category, as further described in BC Hydro's response to CEABC IR 1.20.1.**

Modified Table 4-12 IPP and Long-Term Purchase Volumes for the Integrated System, Extended with Forecast for F2022 to F2031 (October 2018 Forecast)

Call Process (GWh)	EPAs	F17 RRA	F17 Actual	F18 RRA	F18 Actual	F19 RRA	F19 Forecast	F2020 Plan	F2021 Plan	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Pre-2003 Electricity Purchase Agreements	31	3,307	3,498	3,350	3,315	3,139	3,289	3,301	3,350	3,344	3,345	3,430	3,368	3,335	3,314	3,290	3,255	3,136	3,137
2003 Green Power Generation Call	6	562	591	562	557	562	565	566	566	566	566	566	566	564	560	560	560	560	560
2006 Open Call	17	2,129	2,235	2,135	2,132	2,135	2,136	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178
2008 Bioenergy Call - Phase 1	2	188	199	188	191	188	161	204	216	198	198	198	198	198	198	198	198	149	109
2008/10 Standing Offer Program	26	295	293	431	338	517	407	486	522	522	522	522	522	522	522	522	522	522	522
2010 Bioenergy Call - Phase 2	4	282	151	725	209	725	568	680	680	680	680	680	686	705	705	705	705	705	705
2010 Clean Power Call	20	1,818	1,649	2,705	2,414	2,863	2,647	2,779	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867
2010 Integrated Power Offer	7	1,022	1,040	1,064	1,012	1,074	1,052	1,175	1,145	1,120	1,134	1,134	1,134	1,134	1,134	1,134	1,122	1,132	1,058
Negotiated Electricity Purchase Agreements[1]	14	3,700	3,989	3,712	4,185	3,703	3,801	4,010	4,369	4,519	4,473	4,484	4,484	4,484	4,484	4,484	4,484	4,388	4,361
Expected Standing Offer Program Projects	7	71	-	130	-	291	6	70	149	230	230	230	230	230	230	230	230	230	230
Total	134	13,375	13,644	15,002	14,354	15,199	14,631	15,449	16,040	16,222	16,191	16,287	16,232	16,216	16,191	16,166	16,120	15,867	15,727

1. The Surplus Power Rights Agreement is not included in fiscal 2022 to fiscal 2031.

Modified Table 4-13 Breakdown of IPP and Long-Term Commitments for the Integrated System, Extended with Forecast for F2022 to F2031 (October 2018 Forecast)

Call Process ($millions)	EPAs	F17 RRA	F17 Actual	F18 RRA	F18 Actual	F19 RRA	F19 Forecast	F2020 Plan	F2021 Plan	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Pre-2003 Electricity Purchase Agreements	31	277.2	287.3	281.0	276.1	261.6	261.9	268.5	276.3	280.0	269.0	282.9	307.3	310.6	313.7	318.1	323.1	318.6	324.3
2003 Green Power Generation Call	6	33.3	34.9	33.7	32.9	34.1	34.0	34.6	35.0	35.4	35.9	36.3	36.7	36.9	37.1	37.8	43.2	44.6	45.7
2006 Open Call	17	188.4	187.5	190.8	187.2	192.7	184.5	196.9	199.0	201.2	203.3	205.9	208.4	210.7	213.0	215.4	217.1	216.5	213.8
2008 Bioenergy Call - Phase 1	2	22.7	22.0	23.0	25.0	23.3	21.7	24.4	20.1	17.5	17.9	18.2	18.6	19.0	19.4	19.7	20.1	15.4	11.4
2008/10 Standing Offer Program	26	28.9	28.2	43.8	33.2	52.6	41.8	50.5	54.4	55.0	55.6	56.2	56.8	57.4	58.1	58.8	59.4	60.0	60.7
2010 Bioenergy Call - Phase 2	4	39.2	20.2	99.7	29.6	100.9	83.0	98.3	99.6	100.9	102.2	103.5	105.9	110.1	111.5	113.0	114.5	116.0	117.5
2010 Clean Power Call	20	242.0	213.0	336.0	296.4	358.3	318.6	353.7	367.6	371.0	374.7	378.6	382.3	386.7	390.9	395.4	399.8	404.4	409.1
2010 Integrated Power Offer	7	126.5	128.4	131.2	127.1	135.1	138.0	156.9	149.8	140.2	140.9	143.7	146.6	149.5	152.5	155.6	148.7	149.6	141.8
Negotiated Electricity Purchase Agreements[1]	14	346.5	353.2	357.1	374.2	359.9	349.9	381.2	416.0	432.0	436.4	445.1	449.5	459.2	467.8	476.7	485.3	485.5	490.9
Expected Standing Offer Program Projects	7	7.8	-	13.6	-	29.2	0.7	8.1	16.4	25.4	25.7	25.9	26.2	26.4	26.7	27.0	27.2	27.5	27.8
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	1,658.7	1,661.4	1,696.3	1,738.3	1,766.5	1,790.7	1,817.4	1,838.5	1,838.2	1,843.0
Accounting Adjustments	n/a	(78.1)	(61.6)	(140.2)	(70.1)	(108.6)	(107.8)	(34.7)	(33.2)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
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	1,658.7	1,661.4	1,696.3	1,738.3	1,766.5	1,790.7	1,817.4	1,838.5	1,838.2	1,843.0

1 The Surplus Power Rights Agreement and the Residual Capacity Agreement are not included in fiscal 2022 to fiscal 2031.

2.98.6 Are 'Expected Standing Offer Program Projects' projects that are already negotiated? Please explain.

RESPONSE:

As of October 1, 2018, the “Expected Standing Offer Program Projects”[1] values were based on expected values for future potential EPAs that were not yet executed. However, since October 1, 2018, BC Hydro has executed agreements for two of the seven expected EPAs. The seven expected EPAs are associated with First Nations’ clean energy projects that are part of Impact Benefit Agreements with BC Hydro and/or are Standing Offer Program projects that are mature and have significant First Nations involvement.

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1 Please note that the row heading “Expected Standing Offer Program Projects” in Modified Table 4-12 and Table 4-13 above should be “Expected SOP Projects and other First Nations Commitments”, as set out in Table 4-12 and Table 4-13 of the Application.

98.0 Reference: Exhibit B-6, CEC 1.20.1

RESPONSE:

BC Hydro provides the following modified versions of Table 4-12 and Table 4-13 from the Application which have been extended to include the forecast from fiscal 2022 to fiscal 2031. BC Hydro notes that the amounts for accounting adjustments and two energy supply contracts[1] have not been included in fiscal 2022 to fiscal 2031 because we have not developed a forecast for this entire term.

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[1] **The two energy supply contracts, Surplus Power Rights Agreement and the Residual Capacity Agreement, included in the "Negotiated EPA" category, as further described in BC Hydro's response to CEABC IR 1.20.1.**

Modified Table 4-12 IPP and Long-Term Purchase Volumes for the Integrated System, Extended with Forecast for F2022 to F2031 (October 2018 Forecast)

Call Process (GWh)	EPAs	F17 RRA	F17 Actual	F18 RRA	F18 Actual	F19 RRA	F19 Forecast	F2020 Plan	F2021 Plan	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Pre-2003 Electricity Purchase Agreements	31	3,307	3,498	3,350	3,315	3,139	3,289	3,301	3,350	3,344	3,345	3,430	3,368	3,335	3,314	3,290	3,255	3,136	3,137
2003 Green Power Generation Call	6	562	591	562	557	562	565	566	566	566	566	566	566	564	560	560	560	560	560
2006 Open Call	17	2,129	2,235	2,135	2,132	2,135	2,136	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178	2,178
2008 Bioenergy Call - Phase 1	2	188	199	188	191	188	161	204	216	198	198	198	198	198	198	198	198	149	109
2008/10 Standing Offer Program	26	295	293	431	338	517	407	486	522	522	522	522	522	522	522	522	522	522	522
2010 Bioenergy Call - Phase 2	4	282	151	725	209	725	568	680	680	680	680	680	686	705	705	705	705	705	705
2010 Clean Power Call	20	1,818	1,649	2,705	2,414	2,863	2,647	2,779	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867	2,867
2010 Integrated Power Offer	7	1,022	1,040	1,064	1,012	1,074	1,052	1,175	1,145	1,120	1,134	1,134	1,134	1,134	1,134	1,134	1,122	1,132	1,058
Negotiated Electricity Purchase Agreements[1]	14	3,700	3,989	3,712	4,185	3,703	3,801	4,010	4,369	4,519	4,473	4,484	4,484	4,484	4,484	4,484	4,484	4,388	4,361
Expected Standing Offer Program Projects	7	71	-	130	-	291	6	70	149	230	230	230	230	230	230	230	230	230	230
Total	134	13,375	13,644	15,002	14,354	15,199	14,631	15,449	16,040	16,222	16,191	16,287	16,232	16,216	16,191	16,166	16,120	15,867	15,727

1. The Surplus Power Rights Agreement is not included in fiscal 2022 to fiscal 2031.

Modified Table 4-13 Breakdown of IPP and Long-Term Commitments for the Integrated System, Extended with Forecast for F2022 to F2031 (October 2018 Forecast)

Call Process ($millions)	EPAs	F17 RRA	F17 Actual	F18 RRA	F18 Actual	F19 RRA	F19 Forecast	F2020 Plan	F2021 Plan	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Pre-2003 Electricity Purchase Agreements	31	277.2	287.3	281.0	276.1	261.6	261.9	268.5	276.3	280.0	269.0	282.9	307.3	310.6	313.7	318.1	323.1	318.6	324.3
2003 Green Power Generation Call	6	33.3	34.9	33.7	32.9	34.1	34.0	34.6	35.0	35.4	35.9	36.3	36.7	36.9	37.1	37.8	43.2	44.6	45.7
2006 Open Call	17	188.4	187.5	190.8	187.2	192.7	184.5	196.9	199.0	201.2	203.3	205.9	208.4	210.7	213.0	215.4	217.1	216.5	213.8
2008 Bioenergy Call - Phase 1	2	22.7	22.0	23.0	25.0	23.3	21.7	24.4	20.1	17.5	17.9	18.2	18.6	19.0	19.4	19.7	20.1	15.4	11.4
2008/10 Standing Offer Program	26	28.9	28.2	43.8	33.2	52.6	41.8	50.5	54.4	55.0	55.6	56.2	56.8	57.4	58.1	58.8	59.4	60.0	60.7
2010 Bioenergy Call - Phase 2	4	39.2	20.2	99.7	29.6	100.9	83.0	98.3	99.6	100.9	102.2	103.5	105.9	110.1	111.5	113.0	114.5	116.0	117.5
2010 Clean Power Call	20	242.0	213.0	336.0	296.4	358.3	318.6	353.7	367.6	371.0	374.7	378.6	382.3	386.7	390.9	395.4	399.8	404.4	409.1
2010 Integrated Power Offer	7	126.5	128.4	131.2	127.1	135.1	138.0	156.9	149.8	140.2	140.9	143.7	146.6	149.5	152.5	155.6	148.7	149.6	141.8
Negotiated Electricity Purchase Agreements[1]	14	346.5	353.2	357.1	374.2	359.9	349.9	381.2	416.0	432.0	436.4	445.1	449.5	459.2	467.8	476.7	485.3	485.5	490.9
Expected Standing Offer Program Projects	7	7.8	-	13.6	-	29.2	0.7	8.1	16.4	25.4	25.7	25.9	26.2	26.4	26.7	27.0	27.2	27.5	27.8
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	1,658.7	1,661.4	1,696.3	1,738.3	1,766.5	1,790.7	1,817.4	1,838.5	1,838.2	1,843.0
Accounting Adjustments	n/a	(78.1)	(61.6)	(140.2)	(70.1)	(108.6)	(107.8)	(34.7)	(33.2)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
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	1,658.7	1,661.4	1,696.3	1,738.3	1,766.5	1,790.7	1,817.4	1,838.5	1,838.2	1,843.0

1. The Surplus Power Rights Agreement and the Residual Capacity Agreement are not included in fiscal 2022 to fiscal 2031.

2.98.6.1 Please provide an explanation for the variations in Expected Standing Offer costs and particularly comment on the significant increase from F2018 and F2019 Forecast to F2022.

RESPONSE:

The variations in volumes and costs for "Expected Standing Offer Program Projects"[1] can largely be explained by the changes in the categorization of projects between the Fiscal 2017 to F2019 RRA and the F2020 to F2021 RRA and the impact of BC Hydro's decision to indefinitely suspend the Standing Offer Program (SOP), as follows:

- **The F2017 RRA, F2018 RRA and F2019 RRA values are based on the IPP forecast as of May 1, 2016. These values largely reflect the expected volumes and costs from the SOP prior to its indefinite suspension (i.e., volumes associated with the 150 GWh/yr annual quota for new EPAs).[2] As discussed in BC Hydro's response to AMPC IR 1.13.1, the actual volumes and costs associated with the F2017 RRA, F2018 RRA and F2019 RRA forecast values are zero because once an SOP EPA is executed, the volumes associated with the EPA are allocated as a new EPA addition under the "2008/2010 Standing Offer Program" category and removed from the "Expected Standing Offer Program Projects" category; and**
- **The F2019 Forecast to fiscal 2022 values are based on the IPP forecast as of October 1, 2018. Consistent with the indefinite suspension of the SOP, the expected volumes and costs only reflect future EPAs associated with seven First Nations' clean energy projects that are part of Impact Benefit Agreements with BC Hydro and/or are SOP projects that are mature and have significant First Nations involvement. The energy and cost values increase over this period as projects are expected to begin commercial operations as well as the effects of annual price escalation on the costs.**

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1 **Please note that the row heading "Expected Standing Offer Program Projects" in Modified Tables 4-12 and 4-13 above should be "Expected SOP Projects and other First Nations Commitments", as set out in Table 4-12 and Table 4-13 of the Application.**

2 **The F2017 RRA, F2018 RRA and F2019 RRA values also included one co-generation project that is no longer going ahead and is not included as part of the forecast for the Test Period.**

99.0 Reference: Exhibit B-6, CEC 1.21.1 and 1.22.1 and 1.22.2

1.21.1 Please provide the surplus energy quantities BC Hydro expects to have and has had for the period 2017 to 2031 to match the long-term energy supply data requested.

RESPONSE:

BC Hydro assumes that "long-term energy supply data requested" refers to the forecasted IPP and Long-Term Purchase Volumes provided in BC Hydro's response to CEC IR 1.20.1.

The surplus energy quantities BC Hydro expects to have and has had for the period fiscal 2017 to fiscal 2031 are shown in Table 1 below. The forecast surplus is shown for both the operational and planning view of the load resource balance (LRB).

For the operational view of the LRB, the forecast IPP and Long-Term Purchase Volumes provided in CEC IR 1.20.1 are used. The planning view LRB is based on the same vintage of IPP forecast as the operating view, but reflects the capability of IPP resources based on BC Hydro's planning criteria.

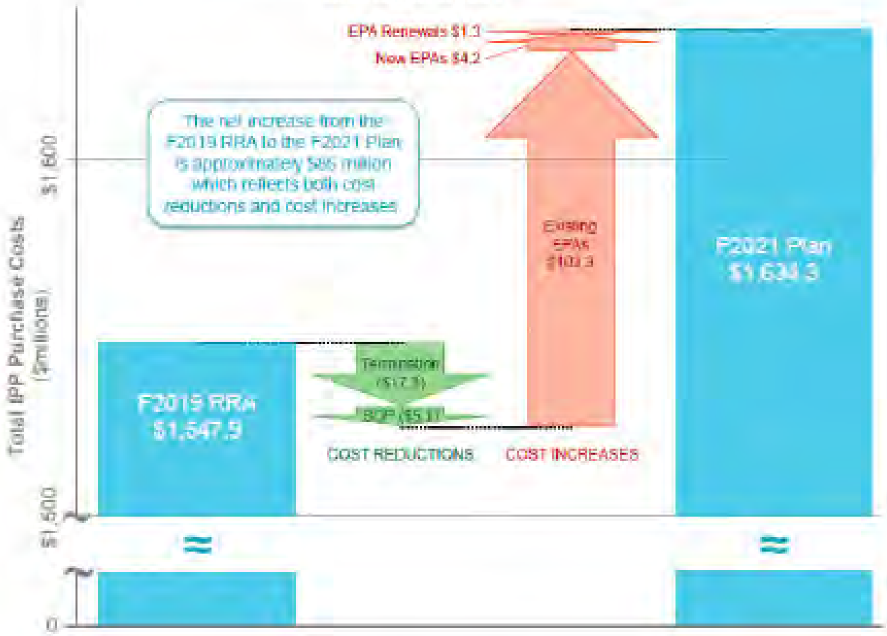
Table 1 Energy Surplus/Deficit based on Operational and Planning View

	Actual		Forecast												
Surplus/Deficit (GWh)	**F2017**	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**
Operational View (Energy Study)	4,053	2,274	(2,631)	2,985	3,834	4,318	4,119	3,029							
Planning View (Oct 2018 Load Forecast)				5,677	6,293	6,517	6,191	5,348							
Planning View (adj. May 2016 Load Forecast)				6,313	6,299	5,413*	4,511	3,600	5,456	5,758	4,514	3,738	2,923	1,835	804

* This value differs from Table 3 in Attachment 1 to BCUC IR 1.15.3 due to an error made in Line 3 of Table 3. The IPP Renewal amount for fiscal 2022 should have been 1,352 GWh, instead of 1,201 GWh. The surplus shown in this table contains the corrected amount.

Please also refer to BC Hydro's response to BCUC IR 1.15.3 where we provide an updated Load Resource Balance.

Figure 4-2 **Breakdown of Total IPP Purchase Cost Forecast Increases from Fiscal 2019 RRA to Fiscal 2021**[135]



1.22.1 Please provide the number of EPA renewals and GWh that are included in the $1.3 million of EPA renewals.

RESPONSE:

There are 14 Electricity Purchase Agreements (EPAs) that are included in the "EPA Renewal" category shown in Figure 4-2 of the Application which account for approximately 2,900 GWh over the test period[1].

As discussed in section 4.7.1.2 of the Application, the $1.3 million value for EPA renewals in Figure 4-2 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 F2019 RRA to the F2021 Plan of those EPAs that have been renewed since the Previous Application (as of May 2016) 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.

Please refer to BC Hydro's response to BCUC IR 1.15.1.1 for an explanation of the source of the $1.3 million net increase in IPP renewal costs between F2019 RRA and F2021 Plan. Please also refer to BC Hydro's response to BCUC IR 1.17.1 for a description of the indicative nature of Figure 4-2.

1.22.2 Please provide BC Hydro's expected renewals in $ and GWh for the 10 years following to 2031.

RESPONSE:

BC Hydro provides the following table of the assumed Electricity Purchase Agreement (EPA) renewal energy volumes and costs in the 10 year forecast from fiscal 2022 to fiscal 2031. However, as stated in BC Hydro's response to CECIR 1.22.4, BC Hydro does not know which EPAs will be renewed until agreements are made. BC Hydro notes that the EPA renewal assumptions are consistent with the 2013 Integrated Resource Plan with the exception of the Biomass Energy Program.

	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Total Energy (GWh)	1,212	1,301	1,627	1,839	2,115	2,195	2,283	2,689	3,172	3,562
Total Cost ($million)	105.3	146.9	171.9	200.3	220.5	229.7	240.1	279.7	331.2	372.7

2.99.1 Please provide the number of new EPAs that will replace existing or expiring EPAs.

RESPONSE:

BC Hydro is uncertain about the number of new EPAs that will replace existing or expiring EPAs because the outcome of negotiations for both new and renewed EPAs are unknown until the negotiations are completed.

99.0 Reference: Exhibit B-6, CEC 1.21.1 and 1.22.1 and 1.22.2

1.21.1 Please provide the surplus energy quantities BC Hydro expects to have and has had for the period 2017 to 2031 to match the long-term energy supply data requested.

RESPONSE:

BC Hydro assumes that "long-term energy supply data requested" refers to the forecasted IPP and Long-Term Purchase Volumes provided in BC Hydro's response to CEC IR 1.20.1.

The surplus energy quantities BC Hydro expects to have and has had for the period fiscal 2017 to fiscal 2031 are shown in Table 1 below. The forecast surplus is shown for both the operational and planning view of the load resource balance (LRB).

For the operational view of the LRB, the forecast IPP and Long-Term Purchase Volumes provided in CEC IR 1.20.1 are used. The planning view LRB is based on the same vintage of IPP forecast as the operating view, but reflects the capability of IPP resources based on BC Hydro's planning criteria.

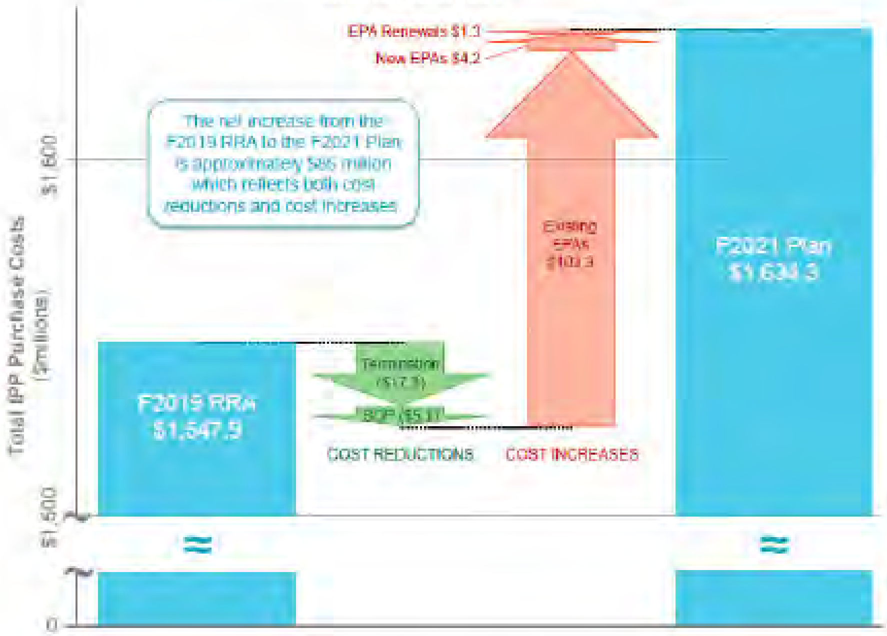
Table 1 Energy Surplus/Deficit based on Operational and Planning View

	Actual			Forecast											
Surplus/Deficit (GWh)	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Operational View (Energy Study)	4,053	2,274	(2,631)	2,985	3,834	4,318	4,119	3,029							
Planning View (Oct 2018 Load Forecast)				5,677	6,293	6,517	6,191	5,348							
Planning View (adj. May 2016 Load Forecast)				6,313	6,299	5,413*	4,511	3,600	5,456	5,758	4,514	3,738	2,923	1,835	804

* This value differs from Table 3 in Attachment 1 to BCUC IR 1.15.3 due to an error made in Line 3 of Table 3. The IPP Renewal amount for fiscal 2022 should have been 1,352 GWh, instead of 1,201 GWh. The surplus shown in this table contains the corrected amount.

Please also refer to BC Hydro's response to BCUC IR 1.15.3 where we provide an updated Load Resource Balance.

Figure 4-2 Breakdown of Total IPP Purchase Cost Forecast Increases from Fiscal 2019 RRA to Fiscal 2021[125]



1.22.1 Please provide the number of EPA renewals and GWh that are included in the $1.3 million of EPA renewals.

RESPONSE:

There are 14 Electricity Purchase Agreements (EPAs) that are included in the "EPA Renewal" category shown in Figure 4-2 of the Application which account for approximately 2,900 GWh over the test period[1].

As discussed in section 4.7.1.2 of the Application, the $1.3 million value for EPA renewals in Figure 4-2 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 F2019 RRA to the F2021 Plan of those EPAs that have been renewed since the Previous Application (as of May 2016) 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.

Please refer to BC Hydro's response to BCUC IR 1.15.1.1 for an explanation of the source of the $1.3 million net increase in IPP renewal costs between F2019 RRA and F2021 Plan. Please also refer to BC Hydro's response to BCUC IR 1.17.1 for a description of the indicative nature of Figure 4-2.

1.22.2 Please provide BC Hydro's expected renewals in $ and GWh for the 10 years following to 2031.

RESPONSE:

BC Hydro provides the following table of the assumed Electricity Purchase Agreement (EPA) renewal energy volumes and costs in the 10 year forecast from fiscal 2022 to fiscal 2031. However, as stated in BC Hydro's response to CECIR 1.22.4, BC Hydro does not know which EPAs will be renewed until agreements are made. BC Hydro notes that the EPA renewal assumptions are consistent with the 2013 Integrated Resource Plan with the exception of the Biomass Energy Program.

	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Total Energy (GWh)	1,212	1,301	1,627	1,839	2,115	2,195	2,283	2,689	3,172	3,562
Total Cost ($million)	105.3	146.9	171.9	200.3	220.5	229.7	240.1	279.7	331.2	372.7

2.99.2 Please develop a scenario in which BC Hydro renews 50% of the expected IPP renewals and New EPAs and utilizes DSM to the extent necessary to address any supply gaps.

RESPONSE:

This answer also responds to CEC IRs 2.99.2.1, 2.99.3, and 2.99.3.1.

BC Hydro is unable to provide the requested scenario and cost comparisons, as fulfilling this request would require a significant amount of new work and additional time to respond to this request, including:

- **Development of a DSM program that would address any supply gaps as a result of the changes in assumptions for new and renewed EPAs; and**
- **Running the associated Energy Studies to determine the operational impacts and costs of the proposed scenario, including extension of the Energy Study period to include fiscal 2031[1].**

BC Hydro will be looking at scenarios related to meeting long term need, including planned reliance on EPA renewals and demand-side management, in BC Hydro's 2021 Integrated Resource Plan.

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[1] **Please note that the Energy Studies do not currently cover the requested period to fiscal 2031.**

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99.0 Reference: Exhibit B-6, CEC 1.21.1 and 1.22.1 and 1.22.2

1.21.1 Please provide the surplus energy quantities BC Hydro expects to have and has had for the period 2017 to 2031 to match the long-term energy supply data requested.

RESPONSE:

BC Hydro assumes that "long-term energy supply data requested" refers to the forecasted IPP and Long-Term Purchase Volumes provided in BC Hydro's response to CEC IR 1.20.1.

The surplus energy quantities BC Hydro expects to have and has had for the period fiscal 2017 to fiscal 2031 are shown in Table 1 below. The forecast surplus is shown for both the operational and planning view of the load resource balance (LRB).

For the operational view of the LRB, the forecast IPP and Long-Term Purchase Volumes provided in CEC IR 1.20.1 are used. The planning view LRB is based on the same vintage of IPP forecast as the operating view, but reflects the capability of IPP resources based on BC Hydro's planning criteria.

Table 1 Energy Surplus/Deficit based on Operational and Planning View

	Actual			Forecast											
Surplus/Deficit (GWh)	**F2017**	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**
Operational View (Energy Study)	4,053	2,274	(2,631)	2,985	3,834	4,318	4,119	3,029							
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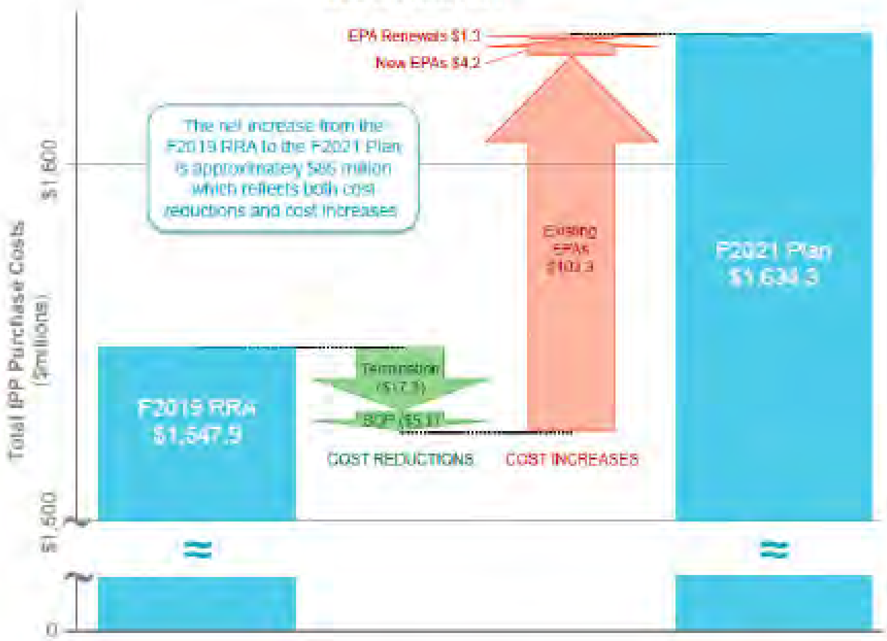
* This value differs from Table 3 in Attachment 1 to BCUC IR 1.15.3 due to an error made in Line 3 of Table 3. The IPP Renewal amount for fiscal 2022 should have been 1,352 GWh, instead of 1,201 GWh. The surplus shown in this table contains the corrected amount.

Please also refer to BC Hydro's response to BCUC IR 1.15.3 where we provide an updated Load Resource Balance.

Figure 4-2 Breakdown of Total IPP Purchase Cost Forecast Increases from Fiscal 2019 RRA to Fiscal 2021[135]



1.22.1 Please provide the number of EPA renewals and GWh that are included in the $1.3 million of EPA renewals.

RESPONSE:

There are 14 Electricity Purchase Agreements (EPAs) that are included in the "EPA Renewal" category shown in Figure 4-2 of the Application which account for approximately 2,900 GWh over the test period[1].

As discussed in section 4.7.1.2 of the Application, the $1.3 million value for EPA renewals in Figure 4-2 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 F2019 RRA to the F2021 Plan of those EPAs that have been renewed since the Previous Application (as of May 2016) 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.

Please refer to BC Hydro's response to BCUC IR 1.15.1.1 for an explanation of the source of the $1.3 million net increase in IPP renewal costs between F2019 RRA and F2021 Plan. Please also refer to BC Hydro's response to BCUC IR 1.17.1 for a description of the indicative nature of Figure 4-2.

1.22.2 Please provide BC Hydro's expected renewals in $ and GWh for the 10 years following to 2031.

RESPONSE:

BC Hydro provides the following table of the assumed Electricity Purchase Agreement (EPA) renewal energy volumes and costs in the 10 year forecast from fiscal 2022 to fiscal 2031. However, as stated in BC Hydro's response to CECIR 1.22.4, BC Hydro does not know which EPAs will be renewed until agreements are made. BC Hydro notes that the EPA renewal assumptions are consistent with the 2013 Integrated Resource Plan with the exception of the Biomass Energy Program.

	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Total Energy (GWh)	1,212	1,301	1,627	1,839	2,115	2,195	2,283	2,689	3,172	3,562
Total Cost ($million)	105.3	146.9	171.9	200.3	220.5	229.7	240.1	279.7	331.2	372.7

2.99.2.1 Please provide a comparison of the total cost of the scenario as compared to BC Hydro's planned resources and provide a breakdown in tabular form as shown in CEC 1.22.2 and as illustrated in Figure 4.2. Please provide from Fiscal 2019-2021 and through to fiscal 2031.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.99.2 for a description of the reasons why BC Hydro cannot provide the requested information.

99.0 Reference: Exhibit B-6, CEC 1.21.1 and 1.22.1 and 1.22.2

1.21.1 Please provide the surplus energy quantities BC Hydro expects to have and has had for the period 2017 to 2031 to match the long-term energy supply data requested.

RESPONSE:

BC Hydro assumes that "long-term energy supply data requested" refers to the forecasted IPP and Long-Term Purchase Volumes provided in BC Hydro's response to CEC IR 1.20.1.

The surplus energy quantities BC Hydro expects to have and has had for the period fiscal 2017 to fiscal 2031 are shown in Table 1 below. The forecast surplus is shown for both the operational and planning view of the load resource balance (LRB).

For the operational view of the LRB, the forecast IPP and Long-Term Purchase Volumes provided in CEC IR 1.20.1 are used. The planning view LRB is based on the same vintage of IPP forecast as the operating view, but reflects the capability of IPP resources based on BC Hydro's planning criteria.

Table 1 Energy Surplus/Deficit based on Operational and Planning View

	Actual			Forecast											
Surplus/Deficit (GWh)	**F2017**	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**
Operational View (Energy Study)	4,053	2,274	(2,631)	2,985	3,834	4,318	4,119	3,029							
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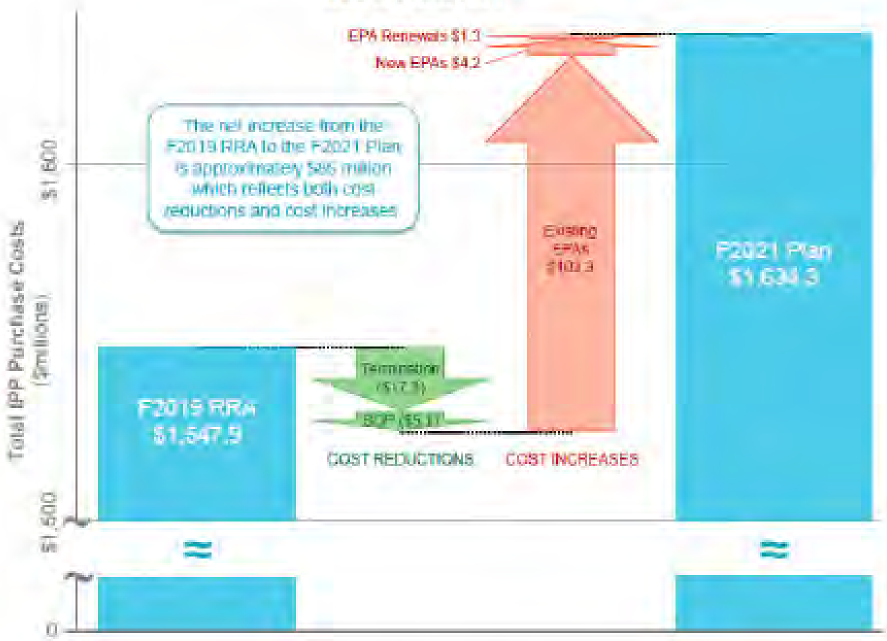
* This value differs from Table 3 in Attachment 1 to BCUC IR 1.15.3 due to an error made in Line 3 of Table 3. The IPP Renewal amount for fiscal 2022 should have been 1,352 GWh, instead of 1,201 GWh. The surplus shown in this table contains the corrected amount.

Please also refer to BC Hydro's response to BCUC IR 1.15.3 where we provide an updated Load Resource Balance.

Figure 4-2 Breakdown of Total IPP Purchase Cost Forecast Increases from Fiscal 2019 RRA to Fiscal 2021[134]



1.22.1 Please provide the number of EPA renewals and GWh that are included in the $1.3 million of EPA renewals.

RESPONSE:

There are 14 Electricity Purchase Agreements (EPAs) that are included in the "EPA Renewal" category shown in Figure 4-2 of the Application which account for approximately 2,900 GWh over the test period[1].

As discussed in section 4.7.1.2 of the Application, the $1.3 million value for EPA renewals in Figure 4-2 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 F2019 RRA to the F2021 Plan of those EPAs that have been renewed since the Previous Application (as of May 2016) 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.

Please refer to BC Hydro's response to BCUC IR 1.15.1.1 for an explanation of the source of the $1.3 million net increase in IPP renewal costs between F2019 RRA and F2021 Plan. Please also refer to BC Hydro's response to BCUC IR 1.17.1 for a description of the indicative nature of Figure 4-2.

1.22.2 Please provide BC Hydro's expected renewals in $ and GWh for the 10 years following to 2031.

RESPONSE:

BC Hydro provides the following table of the assumed Electricity Purchase Agreement (EPA) renewal energy volumes and costs in the 10 year forecast from fiscal 2022 to fiscal 2031. However, as stated in BC Hydro's response to CECIR 1.22.4, BC Hydro does not know which EPAs will be renewed until agreements are made. BC Hydro notes that the EPA renewal assumptions are consistent with the 2013 Integrated Resource Plan with the exception of the Biomass Energy Program.

	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Total Energy (GWh)	1,212	1,301	1,627	1,839	2,115	2,195	2,283	2,689	3,172	3,562
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2.99.3 Please develop a scenario in which BC Hydro renews 25% of the expected IPP renewals and new EPAs and utilizes DSM to the extent necessary to address any supply gaps.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.99.2 for a description of the reasons why BC Hydro cannot provide the requested information.

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99.0 Reference: Exhibit B-6, CEC 1.21.1 and 1.22.1 and 1.22.2

1.21.1 Please provide the surplus energy quantities BC Hydro expects to have and has had for the period 2017 to 2031 to match the long-term energy supply data requested.

RESPONSE:

BC Hydro assumes that "long-term energy supply data requested" refers to the forecasted IPP and Long-Term Purchase Volumes provided in BC Hydro's response to CEC IR 1.20.1.

The surplus energy quantities BC Hydro expects to have and has had for the period fiscal 2017 to fiscal 2031 are shown in Table 1 below. The forecast surplus is shown for both the operational and planning view of the load resource balance (LRB).

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	Actual			Forecast											
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* This value differs from Table 3 in Attachment 1 to BCUC IR 1.15.3 due to an error made in Line 3 of Table 3. The IPP Renewal amount for fiscal 2022 should have been 1,352 GWh, instead of 1,201 GWh.
The surplus shown in this table contains the corrected amount.

Please also refer to BC Hydro's response to BCUC IR 1.15.3 where we provide an updated Load Resource Balance.

Commercial Energy Consumers Association of British Columbia Information Request No. **2.99.3.1** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 2 of 3
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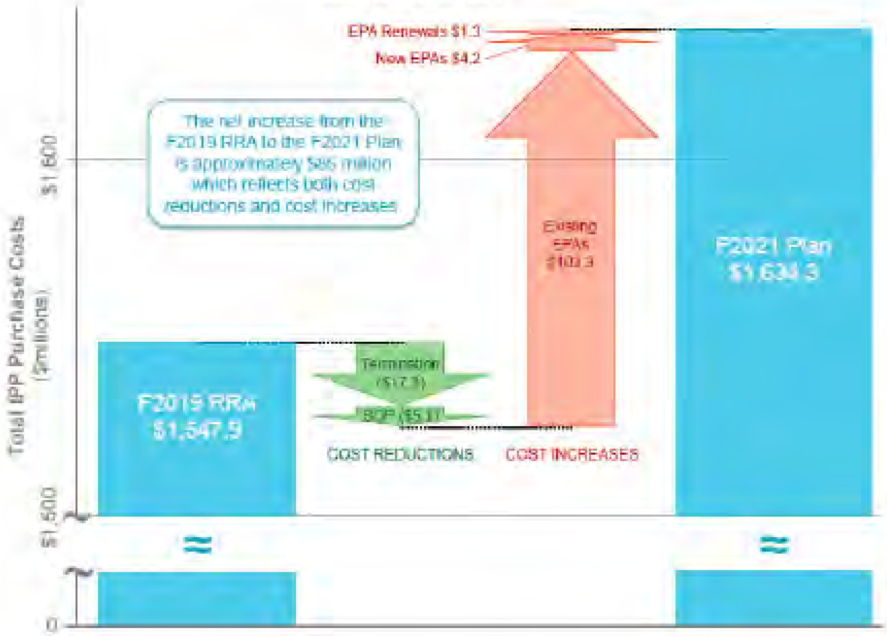
Figure 4-2 Breakdown of Total IPP Purchase Cost Forecast Increases from Fiscal 2019 RRA to Fiscal 2021[135]



1.22.1 Please provide the number of EPA renewals and GWh that are included in the $1.3 million of EPA renewals.

RESPONSE:

There are 14 Electricity Purchase Agreements (EPAs) that are included in the "EPA Renewal" category shown in Figure 4-2 of the Application which account for approximately 2,900 GWh over the test period[1].

As discussed in section 4.7.1.2 of the Application, the $1.3 million value for EPA renewals in Figure 4-2 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 F2019 RRA to the F2021 Plan of those EPAs that have been renewed since the Previous Application (as of May 2016) 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.

Please refer to BC Hydro's response to BCUC IR 1.15.1.1 for an explanation of the source of the $1.3 million net increase in IPP renewal costs between F2019 RRA and F2021 Plan. Please also refer to BC Hydro's response to BCUC IR 1.17.1 for a description of the indicative nature of Figure 4-2.

1.22.2 Please provide BC Hydro's expected renewals in $ and GWh for the 10 years following to 2031.

RESPONSE:

BC Hydro provides the following table of the assumed Electricity Purchase Agreement (EPA) renewal energy volumes and costs in the 10 year forecast from fiscal 2022 to fiscal 2031. However, as stated in BC Hydro's response to CECIR 1.22.4, BC Hydro does not know which EPAs will be renewed until agreements are made. BC Hydro notes that the EPA renewal assumptions are consistent with the 2013 Integrated Resource Plan with the exception of the Biomass Energy Program.

	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
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Total Cost ($million)	105.3	146.9	171.9	200.3	220.5	229.7	240.1	279.7	331.2	372.7

2.99.3.1 Please provide a comparison of the total cost of the scenario as compared to BC Hydro's planned resources and provide a breakdown in tabular form as shown in CEC 1.22.2 and as illustrated in Figure 4.2. Please provide from Fiscal 2019-2021 and through to fiscal 2031.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.99.2 for a description of the reasons why BC Hydro cannot provide the requested information.

100.0 Reference: Exhibit B-6, CEC 1.27.1

Accenture repatriation and the Workforce Optimization program, as well as workforce growth associated with the Site C Project. These increases are partially offset by a reduction of apprentice and trainee intakes based on future resourcing requirements. The table below provides a breakdown of these FTE changes:

	FTEs
Workforce Optimization Program	475
Accenture Repatriation	423
Site C Project	190
Overtime FTE Changes	21
Reduction of Apprentice Intakes and Graduations	(75)
Miscellaneous changes to regular time FTEs	6
Total	1,040

2.100.1 Please explain the 'Reduction of Apprentice Intakes and Graduations' and any permanent or temporary changes that BC Hydro may be making to any of its programs related to these reductions.

RESPONSE:

The only change to BC Hydro's apprentice and trainee programs is a reduction in the number of new hire cohorts. The program contents have not changed.

As discussed in BC Hydro's response to BCUC IR 1.51.1, the reduction in Apprentices and Trainees will be achieved through graduations and fewer new hires. The reduction is not expected to have any implications to BC Hydro operations because it is based on resource planning forecasts that account for attrition rates. In recent years, attrition in journey people positions has declined, which means that fewer Apprentices and Trainee new hires are required.

101.0 Reference: Exhibit B-6, CEC 1.27.3 and 1.63.2

1.27.3 Please explain the 'Other' FTEs in Capital and why Forecast 2019 is nearly 200 FTEs higher (or almost double) that of the 2019 RRA.

RESPONSE:

The additional 192 FTEs in 'Other' Capital from fiscal 2019 RRA to fiscal 2019 forecast primarily relate to the Site C Project. The fiscal 2019 RRA Plan FTEs were based on data from November 2015, while the fiscal 2019 forecast FTEs were based on data from February 2018.

Since the Previous Application, the Project Total Authorized Budget has increased from $8.8 billion to $10.7 billion. The functional groups within the Site C Project with the largest increase in FTEs from fiscal 2019 RRA Plan to fiscal 2019 forecast are shown in the table below.

Site C Functional Group	F2019 RRA	F2019 Forecast	Increase
Construction Mgmt, Resident Engineering, Safety	74	158	84
Engineering	28	66	38
Project Controls, Finance	33	65	32
Other	64	99	35
Total	199	389[1]	189

Note 1 Displayed values are rounded

Construction Management, Resident Engineering, and Safety FTEs increased by 84 due to increased requirements for on-site field and supervision staff.

Engineering FTEs increased by 38 primarily due to a planned shift to a higher proportion of BC Hydro employees conducting engineering work relative to the number of external contractors.

Project Controls and Finance FTEs increased by 32 primarily due to an expansion of the project controls function as recommended by the project's independent advisor, EY Canada. Additional resources were added to the site controls team, including staff for quantity surveying, scheduling, and records and information management.

The remaining increase of 35 FTEs represented as "Other" in the above table can be broken down as follows:

1.63.2 Does BC Hydro still expect the cost estimate to be $10.7 billion, or has this changed? Please explain.

RESPONSE:

BC Hydro continues to forecast to complete the Site C Project within the approved budget of $10.7 billion.

2.101.1 Please confirm that BC Hydro will provide any updates to the Site C budget if available during the RRA process.

RESPONSE:

BC Hydro continues to forecast to complete the Site C Project within the approved budget of $10.7 billion. If there are any updates to the approved budget for the Site C Project during this proceeding, BC Hydro will make the BCUC and interveners aware of the updated approved budget.

101.0 Reference: Exhibit B-6, CEC 1.27.3 and 1.63.2

1.27.3 Please explain the 'Other' FTEs in Capital and why Forecast 2019 is nearly 200 FTEs higher (or almost double) that of the 2019 RRA.

RESPONSE:

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The remaining increase of 35 FTEs represented as "Other" in the above table can be broken down as follows:

1.63.2 Does BC Hydro still expect the cost estimate to be $10.7 billion, or has this changed? Please explain.

RESPONSE:

BC Hydro continues to forecast to complete the Site C Project within the approved budget of $10.7 billion.

2.101.2 Please provide the most updated version of the Site C budget showing the number of FTEs, and forecast to completion as well as progress status.

RESPONSE:

BC Hydro has provided updated information in the Evidentiary Update. There are no changes to fiscal 2020 and fiscal 2021 for the Site C Project with respect to Site C FTEs and capital expenditures.

BC Hydro is continuing to forecast that the River Diversion milestone will be achieved in September 2020, and the first power milestone will be achieved in December 2023, as planned.

The Site C Project continues to forecast to be completed within the project budget of $10.7 billion, including Treasury Board Reserve.

102.0 Reference: Exhibit B-6, CEC 1.30.3 and BCUC 1. 49.3

1.30.3 Please provide the annual total costs of the Accenture contract for the last five years.

RESPONSE:

The table below provides the total operating costs for the Accenture contract from fiscal 2014 to fiscal 2018. Further information on the reduction in costs between fiscal 2016 and fiscal 2018 is provided in BC Hydro's response to BCUC IR 1.49.3.

Actuals ($ million)				
F2014	F2015	F2016	F2017	F2018
62.0	61.5	67.2	48.1	41.9

KBU/Function	Services - ABS F2016 Actuals ($ million)	Services - ABS F2017 Actuals ($ million)	Services - ABS F2018 Actuals ($ million)
Customer Service	31.4	27.4	28.0
Human Resources	4.7	4.9	5.1
Properties	1.7	1.7	1.8
Supply Chain	2.6	2.3	2.4
Technology	0.0	0.0	0.0
Communications and Community Engagement	0.0	0.0	0.0
Finance	0.0	0.0	0.0
Sub-Total	40.4	36.4	37.2
Tempworks	7.9	6.9	4.7
Field Service Representatives	18.8	4.7	0.0
Total	67.1	48.0	41.9

The reduction in actuals from fiscal 2016 to fiscal 2017 is primarily due to the implementation of Smart Metering Infrastructure, as well as the repatriation of the Field Service Representatives in October 2016. The reduction from fiscal 2017 to fiscal 2018 actuals is primarily a result of repatriated Field Service Representatives, as well as a reduction to Tempworks, partly due to a scale back of usage leading up to repatriation.

FTE information prior to the repatriation is not available because the Accenture contract was based on output metrics for an agreed scope and not on the number of employees provided.

2.102.1 Please confirm that it is reasonable to assume that there would be no further significant reductions in the costs of Accenture if the contract had been continued.

RESPONSE:

BC Hydro confirms there would have been no further significant reduction in the costs of the services repatriated from Accenture if the contract had been continued under the same scope, work volumes and service levels.

103.0 Reference: Exhibit B-6, CEC 1.34.4 and Exhibit B-5, BCUC 1.57.3

no planned operating costs associated with this lease in fiscal 2020 and fiscal 2021.

Figure 5-12 of Chapter 5 of the Application (Total Operating Costs per MWh of Sales (BC Hydro Review)) has been extended to include BC Hydro's costs per MWh of sales for fiscal 2019 forecast, fiscal 2020 plan and fiscal 2021 plan. As shown in the chart below, BC Hydro's cost per MWh of sales increases slightly in fiscal 2019 and then begins to level off in fiscal 2020 and fiscal 2021 which is aligned with our expectation of the direction of operating costs and volume of sales. The slight increase in fiscal 2019 relates to the lower forecast sales over the test period due to lower surplus sales.

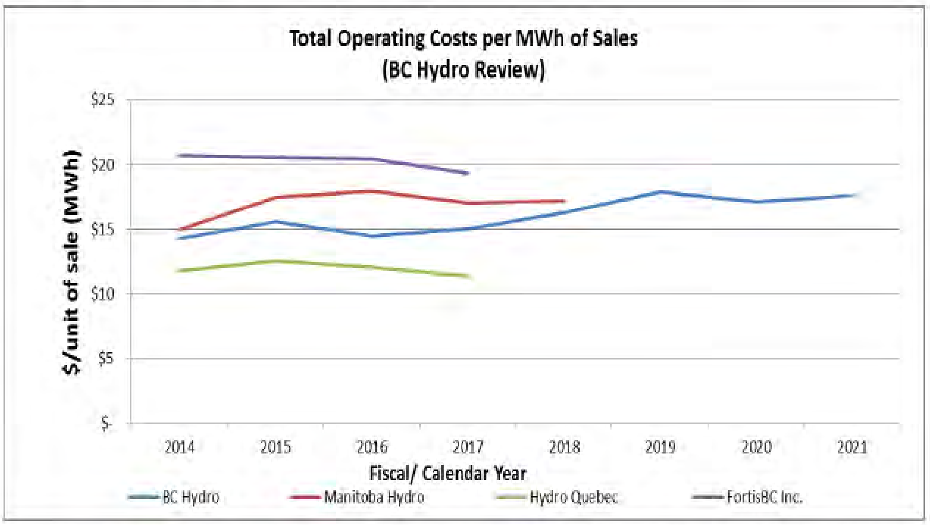

Figure 5-13 of Chapter 5 of the Application (Total Operating Costs per Customer (BC Hydro Review)) has been extended to include BC Hydro costs per customer for fiscal 2019 forecast, fiscal 2020 plan and fiscal 2021 plan. As shown in the chart below, cost per customer increases slightly in fiscal 2019 and then levels off in fiscal 2020 and fiscal 2021 due to an increase in customer base expected over the test period.

2.103.1 Would the other utilities likely have experienced the same issues with accounting treatment changes? Please comment.

RESPONSE:

The two accounting issues relate to smart meters and capital overhead. BC Hydro considers it unlikely that the utilities compared in the review faced the same impacts related to these issues.

With respect to smart meters, BC Hydro understands that the other utilities compared in this review have implemented smart metering technology. BC Hydro therefore expects that BC Hydro and the other utilities all have the ongoing operating costs related to smart meters included in the costs compared in the review.

With respect to capital overhead, BC Hydro understands that Hydro Quebec and FortisBC Inc. apply U.S. GAAP. BC Hydro reviewed publically available financial statements regarding the respective adoption of U.S. GAAP by these utilities and did not identify any transitional adjustments with respect to capital overhead. BC Hydro expects that this means that these utilities did not experience the increase in operating costs experienced by BC Hydro upon adoption of IFRS. BC Hydro understands that, like BC Hydro, Manitoba Hydro utilized a regulatory account to transition to IFRS. The impacts to Manitoba Hydro of doing so may be different than those faced by BC Hydro.

As noted in BC Hydro's response to BCUC IR 1.56.1, BC Hydro conducted a limited review of recent years of published reports for the three entities compared. BC Hydro did not attempt to align the various accounting standards across the comparators as there was not a reliable way to do so.

103.0 Reference: Exhibit B-6, CEC 1.34.4 and Exhibit B-5, BCUC 1.57.3

no planned operating costs associated with this lease in fiscal 2020 and fiscal 2021.

Figure 5-12 of Chapter 5 of the Application (Total Operating Costs per MWh of Sales (BC Hydro Review)) has been extended to include BC Hydro's costs per MWh of sales for fiscal 2019 forecast, fiscal 2020 plan and fiscal 2021 plan. As shown in the chart below, BC Hydro's cost per MWh of sales increases slightly in fiscal 2019 and then begins to level off in fiscal 2020 and fiscal 2021 which is aligned with our expectation of the direction of operating costs and volume of sales. The slight increase in fiscal 2019 relates to the lower forecast sales over the test period due to lower surplus sales.

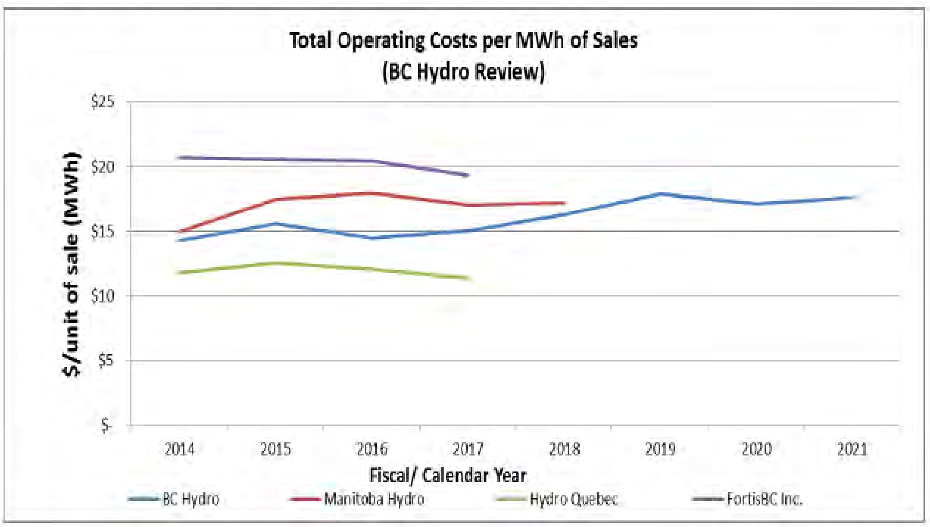

Figure 5-13 of Chapter 5 of the Application (Total Operating Costs per Customer (BC Hydro Review)) has been extended to include BC Hydro costs per customer for fiscal 2019 forecast, fiscal 2020 plan and fiscal 2021 plan. As shown in the chart below, cost per customer increases slightly in fiscal 2019 and then levels off in fiscal 2020 and fiscal 2021 due to an increase in customer base expected over the test period.

2.103.1 Would the other utilities likely have experienced the same issues with accounting treatment changes? Please comment.

2.103.1.1 If yes, can the change in relative cost per MWh of sales be almost entirely attributed to Smoot Metering Infrastructure?

RESPONSE:

No, the change in relative cost per MWh of sales for BC Hydro is not entirely attributable to Smart Metering Infrastructure. As noted in BC Hydro's response to CEC IR 2.103.1.1.1, IFRS ineligible capital overhead also results in an increase to BC Hydro's operating costs and therefore impacts cost per MWh of sales.

103.0 Reference: Exhibit B-6, CEC 1.34.4 and Exhibit B-5, BCUC 1.57.3

no planned operating costs associated with this lease in fiscal 2020 and fiscal 2021.

Figure 5-12 of Chapter 5 of the Application (Total Operating Costs per MWh of Sales (BC Hydro Review)) has been extended to include BC Hydro's costs per MWh of sales for fiscal 2019 forecast, fiscal 2020 plan and fiscal 2021 plan. As shown in the chart below, BC Hydro's cost per MWh of sales increases slightly in fiscal 2019 and then begins to level off in fiscal 2020 and fiscal 2021 which is aligned with our expectation of the direction of operating costs and volume of sales. The slight increase in fiscal 2019 relates to the lower forecast sales over the test period due to lower surplus sales.

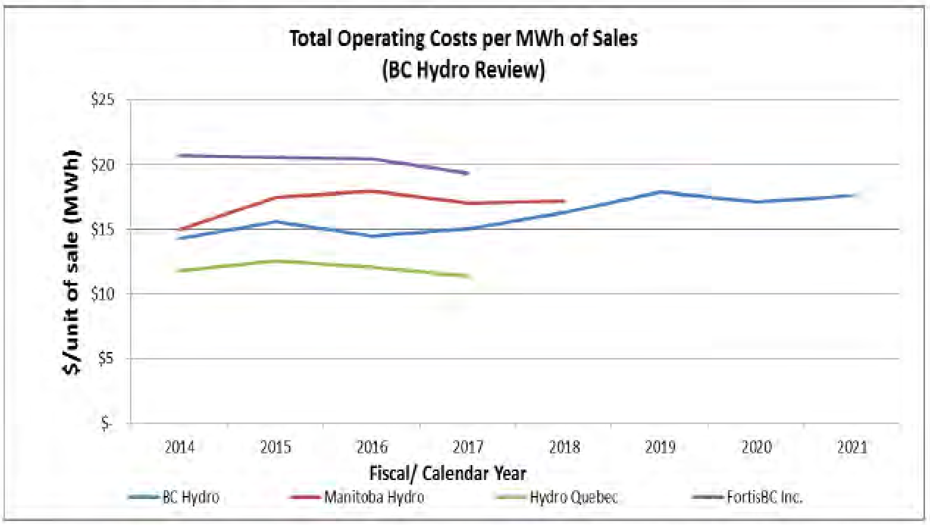

Figure 5-13 of Chapter 5 of the Application (Total Operating Costs per Customer (BC Hydro Review)) has been extended to include BC Hydro costs per customer for fiscal 2019 forecast, fiscal 2020 plan and fiscal 2021 plan. As shown in the chart below, cost per customer increases slightly in fiscal 2019 and then levels off in fiscal 2020 and fiscal 2021 due to an increase in customer base expected over the test period.

2.103.1.1 If yes, can the change in relative cost per MWh of sales be almost entirely attributed to Smoot Metering Infrastructure?

2.103.1.1.1 If not, please identify any other factors that are contributing to the increase in operating costs per MWh of sales.

RESPONSE:

The change in relative cost per MWh of sales for BC Hydro can be partially attributed to Smart Metering Infrastructure costs and the accounting treatment related to overhead costs that are no longer eligible to be capitalized under IFRS. Smart Metering Infrastructure costs are not new costs, but rather expenditures that were deferred in fiscal 2015 and fiscal 2016 pursuant to BCUC Order No. G-48-14.

In BC Hydro's response to BCUC IR 1.57.3, we also noted the following:

> **"BC Hydro expects the cost per MWh of sales and customers to level off beyond fiscal 2021 due to the full absorption of the IFRS ineligible capital overhead in operating costs in fiscal 2023 and the potential forecast increase in the volume of sales and in the customer base beyond fiscal 2021. However, due to the ongoing assessment of the future impact of IPP leases under IFRS 16 and the impact of other potential accounting standard changes, an increase or decrease in operating costs may also be seen. Other factors, including those beyond BC Hydro's control, will also likely drive future increases or decreases in operating costs. For example, discount rates impact current service pension costs, while volatility in storms may continue to cause volatility in BC Hydro's storm budget, which is based on a five-year average."**

103.0 Reference: Exhibit B-6, CEC 1.34.4 and Exhibit B-5, BCUC 1.57.3

no planned operating costs associated with this lease in fiscal 2020 and fiscal 2021.

Figure 5-12 of Chapter 5 of the Application (Total Operating Costs per MWh of Sales (BC Hydro Review)) has been extended to include BC Hydro's costs per MWh of sales for fiscal 2019 forecast, fiscal 2020 plan and fiscal 2021 plan. As shown in the chart below, BC Hydro's cost per MWh of sales increases slightly in fiscal 2019 and then begins to level off in fiscal 2020 and fiscal 2021 which is aligned with our expectation of the direction of operating costs and volume of sales. The slight increase in fiscal 2019 relates to the lower forecast sales over the test period due to lower surplus sales.

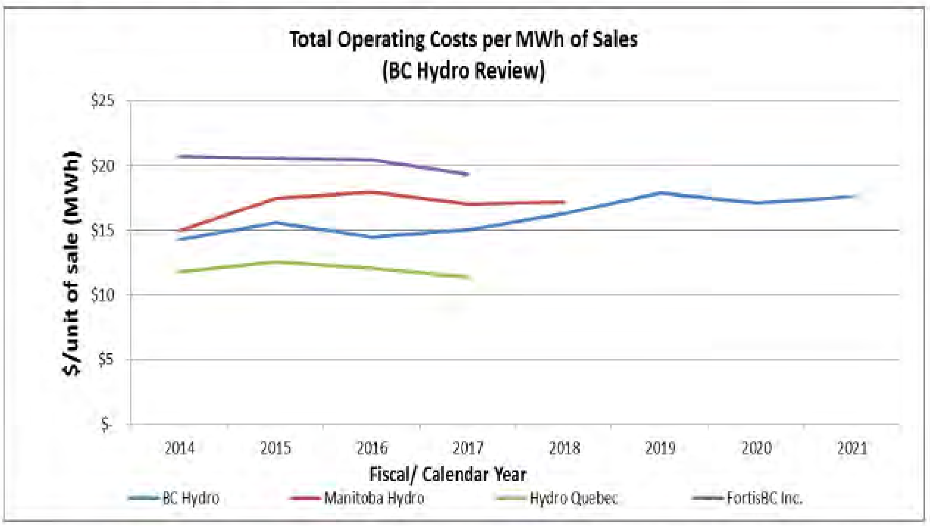

Figure 5-13 of Chapter 5 of the Application (Total Operating Costs per Customer (BC Hydro Review)) has been extended to include BC Hydro costs per customer for fiscal 2019 forecast, fiscal 2020 plan and fiscal 2021 plan. As shown in the chart below, cost per customer increases slightly in fiscal 2019 and then levels off in fiscal 2020 and fiscal 2021 due to an increase in customer base expected over the test period.

2.103.2 Please provide BC Hydro's views as to why the cost/MWh of sales is declining for the other utilities from about 2015/2016 onward.

RESPONSE:

In BC Hydro's view, the cost per MWh of sales for the other utilities appears to be declining slightly from 2015 onward because of a slight increase in the sales volume and a downward trend in operating costs. BC Hydro has not investigated

the detailed cost structure of the three comparators as the information is difficult to source from their respective published financial reports.

Operating costs for Manitoba Hydro and Hydro Quebec have both increased and decreased over the period shown and have remained relatively constant for FortisBC Inc.

Please refer to BC Hydro's response to BCUC IR 1.57.3 and CEC IRs 2.103.1 and 2.103.1.1 for further information on the potential drivers impacting operating costs for the utilities in the comparison review.

Please also refer to Attachment 1 to BC Hydro's response to FORTISBC IR 1.2.1 for the data points used in the comparison review. The data tables provide the operating costs, number of customers, and sales volume for each of the utilities compared in the review. The tables have also been provided below for ease of reference.

Operating Costs ($ Million)	2014	2015	2016	2017	2018
BC Hydro	755	798	829	868	932
Manitoba Hydro	491	563	574	567	549
Hydro Quebec [1]	2,366	2,527	2,438	2,342	
FortisBC Inc. [1]	67	65	64	64	

Sales (GWh)	2014	2015	2016	2017	2018
BC Hydro	53,018	51,213	57,300	57,652	57,173
Manitoba Hydro	32,875	32,269	31,935	33,238	31,953
Hydro Quebec [1]	200,847	201,127	201,989	205,638	
FortisBC Inc. [1]	3,213	3,153	3,121	3,305	

Customers	2014	2015	2016	2017	2018
BC Hydro	1,914,549	1,935,068	1,960,555	1,987,963	2,018,044
Manitoba Hydro	555,760	561,869	567,634	573,438	580,262
Hydro Quebec [1]	4,179,850	4,214,721	4,244,541	4,279,496	
FortisBC Inc. [1]	130,572	131,883	133,550	136,000	

Note:
1. Hydro Quebec and FortisBC report on a calendar year basis. Data for 2018 was not available at time of BC Hydro's filing of the F2020 - F2021 Revenue Requirements

Unit of Measures

Operating Cost per Sales ($/MWh)	2014	2015	2016	2017	2018
BC Hydro	14.24	15.57	14.47	15.05	16.30
Manitoba Hydro	14.94	17.45	17.97	17.06	17.18
Hydro Quebec	11.78	12.56	12.07	11.39	
FortisBC Inc.	20.74	20.58	20.44	19.36	

Cost per Customer	2014	2015	2016	2017	2018
BC Hydro	394.40	412.19	422.99	436.45	461.80
Manitoba Hydro	883.47	1,002.01	1,011.21	988.77	946.12
Hydro Quebec	566.05	599.57	574.38	547.26	
FortisBC Inc.	510.45	492.10	477.72	470.59	

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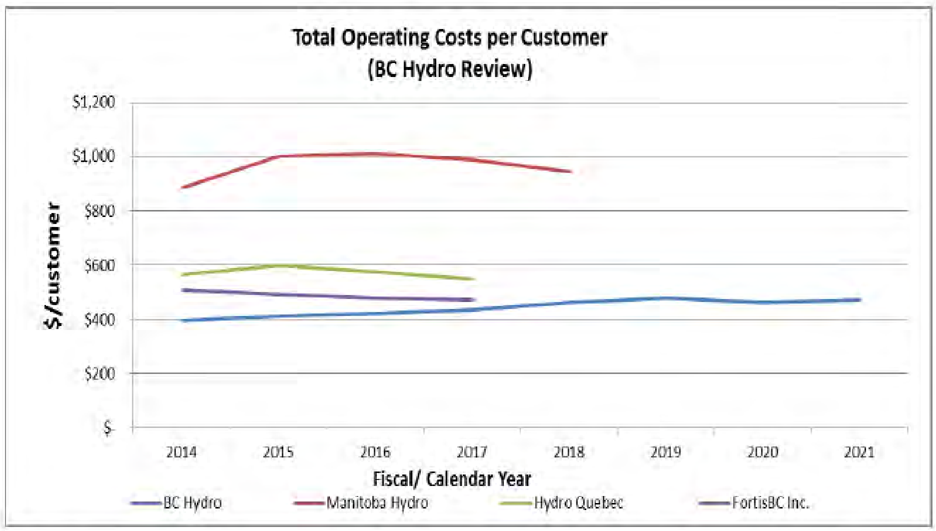
104.0 Reference: Exhibit B-5, BCUC 1.57.3



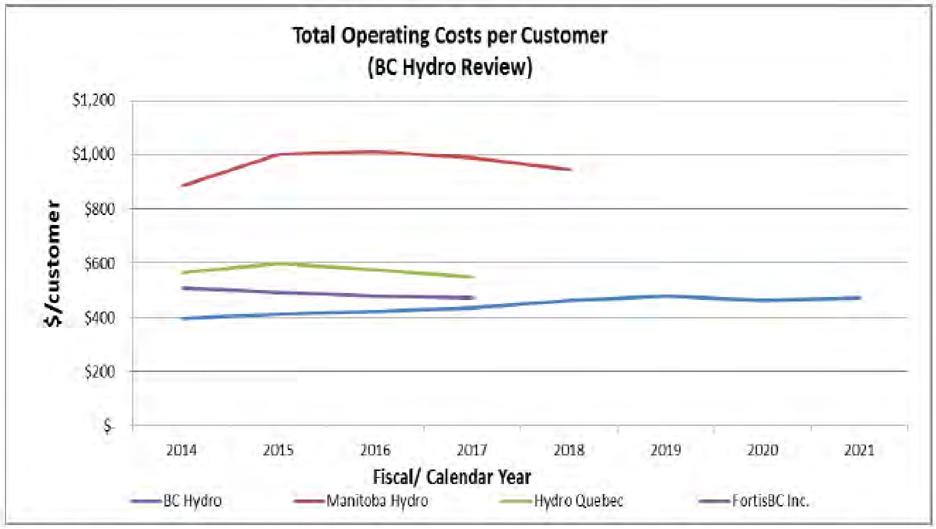
BC Hydro expects the cost per MWh of sales and customers to level off beyond fiscal 2021 due to the full absorption of the IFRS ineligible capital overhead in operating costs in fiscal 2023 and the potential forecast increase in the volume of sales and in the customer base beyond fiscal 2021. However, due to the ongoing assessment of the future impact of IPP leases under IFRS 16 and the impact of other potential accounting standards changes, an increase or decrease in operating costs may also be seen. Other factors, including those beyond BC Hydro's control, will also likely drive future increases or decreases in operating costs. For example, discount rates impact current service pension costs, while the volatility in storms may continue to cause volatility in BC Hydro's storm budget, which is based on a five-year average.

2.104.1 Please provide the number of customers for each of the utilities.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.103.2 which includes the number of customers for each utility compared in the review.

104.0 Reference: Exhibit B-5, BCUC 1.57.3



BC Hydro expects the cost per MWh of sales and customers to level off beyond fiscal 2021 due to the full absorption of the IFRS ineligible capital overhead in operating costs in fiscal 2023 and the potential forecast increase in the volume of sales and in the customer base beyond fiscal 2021. However, due to the ongoing assessment of the future impact of IPP leases under IFRS 16 and the impact of other potential accounting standards changes, an increase or decrease in operating costs may also be seen. Other factors, including those beyond BC Hydro's control, will also likely drive future increases or decreases in operating costs. For example, discount rates impact current service pension costs, while the volatility in storms may continue to cause volatility in BC Hydro's storm budget, which is based on a five-year average.

2.104.2 Please provide BC Hydro's views as to why the costs/customers in the other utilities are declining from 2015 onward.

RESPONSE:

In BC Hydro's view, the cost per customer for the other utilities is declining slightly from 2015 onward because of a slight increase in the number of customers and a downward trend in operating costs. BC Hydro has not investigated the detailed cost structure of the three comparators as the information is difficult to source from their respective published financial reports.

As discussed further in BC Hydro's response to CEC IR 2.103.2, operating costs for Manitoba Hydro and Hydro Quebec have both increased and decreased over the period shown and have remained relatively constant for FortisBC Inc.

105.0 Reference: Exhibit B-6, CEC 1.35.1

35.0 Reference: Exhibit B-1, page 5-56 to 5-57

- **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

1.35.1 Please provide the distribution of the companies by country.

RESPONSE:

Forty-one operating companies participated in the 2018 First Quartile T&D Benchmarking study. Two companies were from Canada and 39 companies were from the U.S.

1.35.2 Please identify the Canadian companies included in the First Quartile reporting.

RESPONSE:

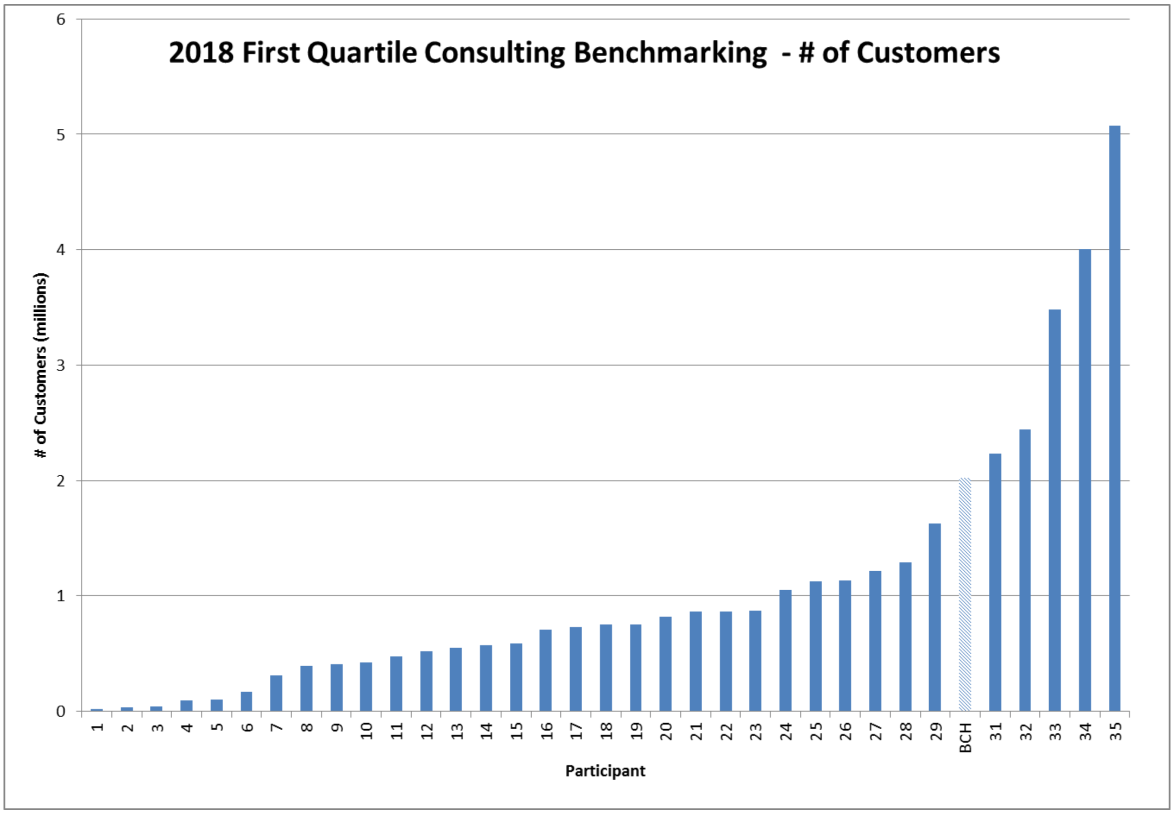
BC Hydro and Hydro Quebec were the two Canadian companies that participated in the 2018 First Quartile T&D Benchmarking study.

2.105.1 Please provide a chart depicting the sizes of the companies by number of customers and sales revenue. Please separate out the 2 Canadian companies.

RESPONSE:

The chart below provides the number of distribution customers served for the 2018 participants. Only 35 of the 41 participants submitted this information. BC Hydro is identified in the chart below. The other Canadian company, Hydro Quebec, did not provide this information.

First Quartile does not survey participants for sales revenue information.



105.0 Reference: Exhibit B-6, CEC 1.35.1

35.0 Reference: Exhibit B-1, page 5-56 to 5-57

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1.35.1 Please provide the distribution of the companies by country.

RESPONSE:

Forty-one operating companies participated in the 2018 First Quartile T&D Benchmarking study. Two companies were from Canada and 39 companies were from the U.S.

1.35.2 Please identify the Canadian companies included in the First Quartile reporting.

RESPONSE:

BC Hydro and Hydro Quebec were the two Canadian companies that participated in the 2018 First Quartile T&D Benchmarking study.

2.105.2 Why did the benchmarking only include 2 Canadian companies?

RESPONSE:

BC Hydro is not aware of the reasons why other Canadian companies do not participate in First Quartile Consulting's T&D Benchmarking study.

106.0 Reference: Exhibit B-6, CEC 1.36.1

36.0 Reference: Exhibit B-1, page 5-57

- **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.

1.36.1 Please provide the distribution of companies by country.

RESPONSE:

The total Navigant GSK Hydro Benchmarking program data base is ~110,000 MW. The following is the breakdown by country:

	(MW)	(%)
Argentina	1,281	1.2
Brazil	2,819	2.6
Chile	267	0.2
Colombia	1,000	0.9
Panama	693	0.6
US	59,509	54.2
Canada	31,892	29.0
China	2,400	2.2
New Zealand	3,780	3.4
Spain	4,497	4.1
Armenia	404	0.4
UK	420	0.4
Finland	864	0.8
Total	109,825	100.0

1.36.2 Please identify the Canadian companies.

RESPONSE:

The list of Canadian utilities included Navigant's GKS Hydro Benchmarking database are:

- **Algonquin Power Company;**
- **BC Hydro;**
- **Churchill Falls (Labrador) Corp.;**
- **Columbia Power Corporation;**
- **FortisBC;**
- **Hydro-Quebec;**
- **Newfoundland & Labrador Hydro;**
- **Nova Scotia Power, Inc.;**
- **Ontario Power Generation;**
- **Rio Tinto;**
- **TransAlta Utilities; and**
- **TransCanada.**

2.106.1 Please provide the number of companies that were included from the US.

RESPONSE:

The number of companies that were included from the U.S. in Navigant's GKS Hydro Benchmarking database was 34.

106.0 Reference: Exhibit B-6, CEC 1.36.1

36.0 Reference: Exhibit B-1, page 5-57

- **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.

1.36.1 Please provide the distribution of companies by country.

RESPONSE:

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	(MW)	(%)
Argentina	1,281	1.2
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US	59,509	54.2
Canada	31,892	29.0
China	2,400	2.2
New Zealand	3,780	3.4
Spain	4,497	4.1
Armenia	404	0.4
UK	420	0.4
Finland	864	0.8
Total	109,825	100.0

1.36.2 Please identify the Canadian companies.

RESPONSE:

The list of Canadian utilities included Navigant's GKS Hydro Benchmarking database are:

- **Algonquin Power Company;**
- **BC Hydro;**
- **Churchill Falls (Labrador) Corp.;**
- **Columbia Power Corporation;**
- **FortisBC;**
- **Hydro-Quebec;**
- **Newfoundland & Labrador Hydro;**
- **Nova Scotia Power, Inc.;**
- **Ontario Power Generation;**
- **Rio Tinto;**
- **TransAlta Utilities; and**
- **TransCanada.**

2.106.2 Please provide the MWh for each of the Canadian companies.

RESPONSE:

The MWh for each of the Canadian companies is provided in the table below.

This response includes commercially sensitive utility-specific information which has been redacted in the public version of the response. The un-redacted version of the response is being made available to the BCUC only, in order to protect the utilities' commercial interests.

Company	Average Water Year (MWh)
Algonquin Power Company	[redacted]
BC Hydro	**45,204,521**
Churchill Falls (Labrador) Corp.	[redacted]
Columbia Power Corporation	[redacted]
FortisBC	[redacted]
Hydro-Quebec	[redacted]
Newfoundland & Labrador Hydro	[redacted]
Nova Scotia Power, Inc.	[redacted]
Ontario Power Generation	[redacted]
Rio Tinto	[redacted]
TransAlta Utilities	[redacted]
TransCanada	[redacted]

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107.0 Reference: Exhibit B-6, CEC 1.38.2

	Integrated Planning	Capital Infrastructure Project Delivery	Operations	Safety	Finance Technolgy Supply Chain	People Customer Corporate Affairs	Other	BC Hydro Total
Table Reference	5A-3	5B-3	5C-3	5D-3	5E-3	5F-3	5G-3	
F2019 RRA	146.2	52.1	537.2	-	-	-	225.6	961.1
Reorganization Impact [1]	123.9	29.8	(321.0)	54.9	265.0	122.5	(275.1)	0.0
Budget Transfers Between Business Groups [2]	9.2	1.0	(1.7)	(0.2)	(6.5)	(9.6)	7.8	0.0
Current Year Budget Transfers Between Business Groups [3]	5.7	(0.2)	5.7	0.7	0.2	(0.4)	(11.7)	0.0
Workforce Optimization Program [4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Accenture Repatriation [5]	0.0	(1.4)	0.0	0.0	0.7	(7.5)	7.0	(1.2)
Other Adjustments	5.8	(1.2)	22.8	1.3	3.2	10.9	(43.8)	(1.0)
F2020 Plan	290.8	80.1	243.0	56.8	262.6	115.9	(90.2)	959.0

2.107.1 Please re-label the table with the units of measurement and a title.

RESPONSE:

The table below provides a revised table to add units of measure and a title.

Budget Transfers and Reorganization Impacts
Fiscal 2019 Revenue Requirements Application Plan
to Fiscal 2020 Plan

($ million)	Integrated Planning	Capital Infrastructure Project Delivery	Operations	Safety	Finance Technolgy Supply Chain	People Customer Corporate Affairs	Other	BC Hydro Total
Table Reference	5A-3	5B-3	5C-3	5D-3	5E-3	5F-3	5G-3	
F2019 RRA	146.2	52.1	537.2	-	-	-	225.6	961.1
Reorganization Impact [1]	123.9	29.8	(321.0)	54.9	265.0	122.5	(275.1)	0.0
Budget Transfers Between Business Groups [2]	9.2	1.0	(1.7)	(0.2)	(6.5)	(9.6)	7.8	0.0
Current Year Budget Transfers Between Business Groups [3]	5.7	(0.2)	5.7	0.7	0.2	(0.4)	(11.7)	0.0
Workforce Optimization Program [4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Accenture Repatriation [5]	0.0	(1.4)	0.0	0.0	0.7	(7.5)	7.0	(1.2)
Other Adjustments	5.8	(1.2)	22.8	1.3	3.2	10.9	(43.8)	(1.0)
F2020 Plan	290.8	80.1	243.0	56.8	262.6	115.9	(90.2)	959.0

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108.0 Reference: Exhibit B-6, CEC 1.39.1

Table 5-23 **FTEs by Business Group and by KBU**

		Schedule Reference	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8	9	10	11	12
	Integrated Planning													
1	Energy Planning and Analytics	16.0 L1	29	29	29	27	27	29	27	31	27	38	44	44
2	Dam Safety	16.0 L2	35	36	35	37	35	34	35	34	35	37	37	37
5	Station Asset Planning	16.0 L3	53	52	53	52	51	51	51	49	51	46	59	59
3	Line Asset Planning	16.0 L4	102	104	102	106	109	109	109	112	109	113	116	116
6	Interconnections and Shared Assets	16.0 L5	40	40	40	40	40	36	40	43	40	47	47	47
4	Engineering	16.0 L6	516	524	516	526	536	540	536	558	536	586	646	646
7	Business Unit Support	16.0 L7	4	3	4	4	4	4	4	3	4	3	3	3
8	Total Integrated Planning BG	16.0 L8	778	788	778	792	802	804	802	830	802	870	952	952
	Capital Infrastructure Project Delivery													
9	Project Delivery	16.0 L9	321	308	321	284	340	324	368	387	368	453	450	450
10	Indigenous Relations	16.0 L10	35	36	35	48	47	57	47	59	47	69	69	69
11	Environment	16.0 L11	80	78	80	85	83	86	83	90	83	89	94	94
12	Properties	16.0 L12	110	106	110	104	106	110	106	114	106	124	123	123
13	Business Unit Support	16.0 L13	0	0	0	3	3	3	3	3	3	3	3	3
14	Total Capital Infrastructure Project Delivery BG	16.0 L14	545	528	545	524	579	581	607	652	607	737	739	739
	Operations													
15	Program and Contract Management	16.0 L15	185	187	185	191	213	205	217	206	217	221	228	228
16	Line Field Operations	16.0 L16	822	826	822	810	844	838	844	856	844	931	938	938
17	Stations Field Operations	16.0 L17	932	871	932	881	856	829	856	818	856	858	777	777
18	Distribution Design & Customer Connect	16.0 L18	304	313	304	335	338	325	338	347	338	379	379	379
19	Construction Services	16.0 L19	478	521	478	454	404	411	404	409	404	398	397	397
20	Generation System Operations	16.0 L20	67	64	67	65	64	65	64	68	64	64	63	63
21	T&D System Operations	16.0 L21	178	174	178	168	165	170	165	174	165	178	197	197
22	Business Unit Support	16.0 L22	3	3	3	3	3	3	3	3	3	3	5	5
23	Total Operations BG	16.0 L23	2,969	2,958	2,969	2,907	2,889	2,845	2,893	2,880	2,893	3,033	2,984	2,984
	Safety													
24	Safety System and Assurance	16.0 L24	65	54	65	48	52	48	52	49	52	52	52	52
25	Learning and Development	16.0 L25	401	433	401	470	438	456	438	437	438	358	317	300
26	Field Safety Services	16.0 L26	52	50	52	52	53	50	55	56	55	63	62	62
27	Security and Emergency Management	16.0 L27	18	18	18	17	18	20	18	25	18	26	31	31
28	Business Unit Support	16.0 L28	0	0	0	2	2	2	2	2	2	2	2	2
29	Total Safety BG	16.0 L29	536	555	536	589	563	576	565	568	565	501	464	447
	Finance, Technology, Supply Chain													
30	Finance	16.0 L30	204	191	204	188	188	194	188	196	188	204	206	206
31	Technology	16.0 L31	183	157	189	168	176	186	191	226	202	263	269	269
32	Supply Chain	16.0 L32	402	423	395	407	402	421	402	447	402	454	468	468
33	Business Unit Support	16.0 L33	3	3	3	3	3	3	3	3	3	3	3	3
34	Total Finance, Technology, Supply Chain BG	16.0 L34	792	774	791	766	769	805	784	871	795	924	946	946
	People, Customer, Corporate Affairs													
35	Human Resources	16.0 L35	103	96	103	84	88	84	88	88	88	125	124	124
36	Customer Service	16.0 L36	124	116	121	116	124	154	124	191	124	495	479	479
37	Conservation and Energy Management	16.0 L37	146	137	142	128	114	110	112	112	112	116	116	116
38	Power Acquisitions and Contract Management	16.0 L38	16	22	16	23	23	26	23	28	23	27	26	26
39	Communications and Community Engagement	16.0 L39	93	118	91	98	86	94	86	95	86	107	107	107
40	Regulatory and Rates	16.0 L40	27	26	27	26	28	23	27	26	27	28	28	28
41	Ethics and Merit Office	16.0 L41	2	2	2	2	1	2	1	3	1	4	5	5
42	Smart Metering & Infrastructure	16.0 L42	53	53	0	25	0	0	0	0	0	0	0	0
43	Business Unit Support	16.0 L43	7	2	7	3	3	3	3	3	3	3	3	3
44	Total People, Customer, Corporate Affairs BG	16.0 L44	570	571	508	506	467	497	463	545	463	906	887	887
	Other													
45	Office of the General Counsel	16.0 L45	38	38	38	37	37	36	37	35	37	43	42	42
46	Office of the President and Chief Operating Officer	16.0 L46	2	3	2	3	4	4	4	3	4	3	3	3
47	Site C Project	16.0 L47	158	97	198	109	186	167	189	226	199	389	460	472
48	Independent Power Producer Capital Leases	16.0 L48	0	0	0	0	0	0	0	0	0	0	0	0
49	Corporate Costs	16.0 L49	0	0	0	0	0	0	0	0	0	0	0	0
50	Capitalized Costs	16.0 L50	0	0	0	0	0	0	0	0	0	0	0	0
51	Total Other BG	16.0 L51	199	138	239	149	227	208	231	264	241	434	505	516
52	Total BC Hydro FTEs	16.0 L60	6,389	6,312	6,365	6,234	6,296	6,315	6,344	6,611	6,365	7,405	7,477	7,471

2.108.1 Please add the following five lines to the above table in a section labelled production and financial summary:

a. Number of customers;
b. MWh;
c. Revenues from energy sales to ratepayers;
d. Total revenues; and
e. Total costs.

RESPONSE:

BC Hydro has added a section labelled "Production and Financial Summary" to Table 5-23 of Chapter 5 of the Application, and included the additional lines 53 to 57 in the table below, as requested in the question. In addition, line 58 has been added in the table below to show that the difference between total revenues and total costs represents the net income.

		Schedule Reference	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Forecast	F2020 Plan	F2021 Plan
			1	2	3	4	5	6	7	8	9	10	11	12
	Integrated Planning													
1	Energy Planning and Analytics	16.0 L1	29	29	29	27	27	29	27	31	27	38	44	44
2	Dam Safety	16.0 L2	35	38	35	37	35	34	35	34	35	37	37	37
5	Station Asset Planning	16.0 L3	53	52	53	52	51	51	51	49	51	46	59	59
3	Line Asset Planning	16.0 L4	102	104	102	106	109	109	109	112	109	113	116	116
6	Interconnections and Shared Assets	16.0 L5	40	40	40	40	40	38	40	43	40	47	47	47
4	Engineering	16.0 L6	516	524	516	526	536	540	536	558	536	586	646	646
7	Business Unit Support	16.0 L7	4	3	4	4	4	4	4	3	4	3	3	3
8	Total Integrated Planning BG	16.0 L8	778	788	778	792	802	804	802	830	802	870	952	952
	Capital Infrastructure Project Delivery													
9	Project Delivery	16.0 L9	321	308	321	284	340	324	368	387	368	453	450	450
10	Indigenous Relations	16.0 L10	35	38	35	48	47	57	47	59	47	69	69	69
11	Environment	16.0 L11	80	78	80	85	83	86	83	90	83	89	94	94
12	Properties	16.0 L12	110	106	110	104	106	110	106	114	106	124	123	123
13	Business Unit Support	16.0 L13	0	0	0	3	3	3	3	3	3	3	3	3
14	Total Capital Infrastructure Project Delivery BG	16.0 L14	545	528	545	524	579	581	607	652	607	737	739	739
	Operations													
15	Program and Contract Management	16.0 L15	185	187	185	191	213	205	217	206	217	221	228	228
16	Line Field Operations	16.0 L16	822	826	822	810	844	838	844	856	844	931	938	938
17	Stations Field Operations	16.0 L17	932	871	932	881	856	829	856	818	856	858	777	777
18	Distribution Design & Customer Connect	16.0 L18	304	313	304	335	338	325	338	347	338	379	379	379
19	Construction Services	16.0 L19	478	521	478	454	404	411	404	409	404	398	397	397
20	Generation System Operations	16.0 L20	67	64	67	65	64	65	64	68	64	64	63	63
21	T&D System Operations	16.0 L21	178	174	178	168	165	170	165	174	165	178	197	197
22	Business Unit Support	16.0 L22	3	3	3	3	3	3	3	3	3	3	5	5
23	Total Operations BG	16.0 L23	2,969	2,958	2,969	2,907	2,889	2,845	2,893	2,880	2,893	3,033	2,984	2,984
	Safety													
24	Safety System and Assurance	16.0 L24	65	54	65	48	52	48	52	49	52	52	52	52
25	Learning and Development	16.0 L25	401	433	401	470	438	456	438	437	438	358	317	300
26	Field Safety Services	16.0 L26	52	50	52	52	53	50	55	56	55	63	62	62
27	Security and Emergency Management	16.0 L27	18	18	18	17	18	20	18	25	18	26	31	31
28	Business Unit Support	16.0 L28	0	0	0	2	2	2	2	2	2	2	2	2
29	Total Safety BG	16.0 L29	536	555	536	589	563	576	565	568	565	501	464	447
	Finance, Technology, Supply Chain													
30	Finance	16.0 L30	204	191	204	188	188	194	188	196	188	204	206	206
31	Technology	16.0 L31	183	157	189	168	176	188	191	226	202	263	269	269
32	Supply Chain	16.0 L32	402	423	395	407	402	421	402	447	402	454	468	468
33	Business Unit Support	16.0 L33	3	3	3	3	3	3	3	3	3	3	3	3
34	Total Finance, Technology, Supply Chain BG	16.0 L34	792	774	791	766	769	805	784	871	795	924	946	946
	People, Customer, Corporate Affairs													
35	Human Resources	16.0 L35	103	96	103	84	88	84	88	88	88	125	124	124
36	Customer Service	16.0 L36	124	116	121	116	124	154	124	191	124	495	479	479
37	Conservation and Energy Management	16.0 L37	146	137	142	128	114	110	112	112	112	116	116	116
38	Power Acquisitions and Contract Management	16.0 L38	16	22	16	23	23	26	23	28	23	27	26	26
39	Communications and Community Engagement	16.0 L39	93	118	91	98	86	94	86	95	86	107	107	107
40	Regulatory and Rates	16.0 L40	27	26	27	26	28	23	27	26	27	28	28	28
41	Ethics and Merit Office	16.0 L41	2	2	2	2	1	2	1	3	1	4	5	5
42	Smart Metering & Infrastructure	16.0 L42	53	53	0	25	0	0	0	0	0	0	0	0
43	Business Unit Support	16.0 L43	7	2	7	3	3	3	3	3	3	3	3	3
44	Total People, Customer, Corporate Affairs BG	16.0 L44	570	571	508	506	467	497	463	545	463	906	887	887
	Other													
45	Office of the General Counsel	16.0 L45	38	38	38	37	37	38	37	35	37	43	42	42
46	Office of the President and Chief Operating Officer	16.0 L46	2	3	2	3	4	4	4	3	4	3	3	3
47	Site C Project	16.0 L47	158	97	198	109	186	167	189	226	199	389	460	472
48	Independent Power Producer Capital Leases	16.0 L48	0	0	0	0	0	0	0	0	0	0	0	0
49	Corporate Costs	16.0 L49	0	0	0	0	0	0	0	0	0	0	0	0
50	Capitalized Costs	16.0 L50	0	0	0	0	0	0	0	0	0	0	0	0
51	Total Other BG	16.0 L51	199	138	239	149	227	208	231	264	241	434	505	516
52	Total BC Hydro FTEs	16.0 L60	6,389	6,312	6,365	6,234	6,296	6,315	6,344	6,611	6,365	7,405	7,477	7,471
	Production and Financial Summary													
53	Number of customers		1,948,867	1,935,068	1,977,635	1,960,555	1,991,447	1,987,963	2,019,465	2,018,044	2,047,420	2,048,469	2,080,305	2,106,890
54	Domestic Sales (GWh)	14.0 L10	53,130	51,199	53,760	51,023	51,860	51,895	51,838	52,102	52,664	52,604	53,567	53,253
55	Dometic revenues ($ million)	14.0 L22	$4,392.9	$4,177.6	$4,699.2	$4,418.7	$4,710.3	$4,709.7	$4,880.2	$4,895.5	$5,101.6	$5,093.4	$4,948.2	$4,942.4
56	Total revenues ($ million)	1.0 L7+24+29	$4,514.2	$4,312.8	$4,825.8	$4,557.3	$4,847.4	$4,852.8	$5,018.4	$5,039.2	$5,242.2	$5,296.3	$5,525.9	$5,564.1
57	Total costs ($ million)	1.0 (L1:L5)+L8+L12+L16+L19	$3,932.7	$3,732.0	$4,173.9	$3,902.3	$4,163.4	$4,169.2	$4,320.4	$4,355.2	$4,530.2	$5,720.6	$4,813.9	$4,852.1
58	Net Income ($ million)	L56 - L57	$581.5	$580.8	$651.9	$655.0	$684.0	$683.5	$698.0	$684.0	$712.0	($424.3)	$712.0	$712.0

The table below contains the same elements as the preceding table, with the addition of fiscal 2019 actual results (Column 10) and updated fiscal 2020 and fiscal 2021 information pursuant to the Evidentiary Update (Columns 11 and 12).

		Schedule Reference	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Actual	F2020 Update	F2021 Update
			1	2	3	4	5	6	7	8	9	10	11	12
	Integrated Planning													
1	Energy Planning and Analytics	16.0 L1	29	29	29	27	27	29	27	31	27	38	44	44
2	Dam Safety	16.0 L2	35	36	35	37	35	34	35	34	35	34	37	37
5	Station Asset Planning	16.0 L3	53	52	53	52	51	51	51	49	51	44	59	59
3	Line Asset Planning	16.0 L4	102	104	102	106	109	109	109	112	109	116	116	116
6	Interconnections and Shared Assets	16.0 L5	40	40	40	40	40	36	40	43	40	46	47	47
4	Engineering	16.0 L6	518	524	516	526	536	540	536	558	536	584	648	648
7	Business Unit Support	16.0 L7	4	3	4	4	4	4	4	3	4	3	3	3
8	Total Integrated Planning BG	16.0 L8	778	788	778	792	802	804	802	830	802	865	952	952
	Capital Infrastructure Project Delivery													
9	Project Delivery	16.0 L9	321	308	321	284	340	324	368	387	368	408	450	450
10	Indigenous Relations	16.0 L10	35	36	35	48	47	57	47	59	47	64	69	69
11	Environment	16.0 L11	80	78	80	85	83	86	83	90	83	90	94	94
12	Properties	16.0 L12	110	106	110	104	106	110	106	114	106	121	123	123
13	Business Unit Support	16.0 L13	0	0	0	3	3	3	3	3	3	3	3	3
14	Total Capital Infrastructure Project Delivery BG	16.0 L14	545	528	545	524	579	581	607	652	607	686	739	739
	Operations													
15	Program and Contract Management	16.0 L15	185	187	185	191	213	205	217	206	217	219	228	228
16	Line Field Operations	16.0 L16	822	826	822	810	844	838	844	856	844	873	938	938
17	Stations Field Operations	16.0 L17	932	871	932	881	856	829	856	818	856	817	777	777
18	Distribution Design & Customer Connect	16.0 L18	304	313	304	335	338	325	338	347	338	360	379	379
19	Construction Services	16.0 L19	478	521	478	454	404	411	404	409	404	424	397	397
20	Generation System Operations	16.0 L20	67	64	67	65	64	65	64	68	64	66	63	63
21	T&D System Operations	16.0 L21	178	174	178	168	165	170	165	174	165	176	197	197
22	Business Unit Support	16.0 L22	3	3	3	3	3	3	3	3	3	5	5	5
23	Total Operations BG	16.0 L23	2,969	2,958	2,969	2,907	2,889	2,845	2,893	2,880	2,893	2,941	2,984	2,984
	Safety													
24	Safety System and Assurance	16.0 L24	65	54	65	48	52	48	52	49	52	46	52	52
25	Learning and Development	16.0 L25	401	433	401	470	438	456	438	437	438	384	317	300
26	Field Safety Services	16.0 L26	52	50	52	52	53	50	55	56	55	66	62	62
27	Security and Emergency Management	16.0 L27	18	18	18	17	18	20	18	25	18	28	31	31
28	Business Unit Support	16.0 L28	0	0	0	2	2	2	2	2	2	2	2	2
29	Total Safety BG	16.0 L29	536	555	536	589	563	576	565	568	565	525	464	447
	Finance, Technology, Supply Chain													
30	Finance	16.0 L30	204	191	204	188	188	194	188	196	188	199	206	206
31	Technology	16.0 L31	183	157	189	168	176	186	191	226	202	264	269	269
32	Supply Chain	16.0 L32	402	423	395	407	402	421	402	447	402	482	468	468
33	Business Unit Support	16.0 L33	3	3	3	3	3	3	3	3	3	3	3	3
34	Total Finance, Technology, Supply Chain BG	16.0 L34	792	774	791	766	769	805	784	871	795	947	946	946
	People, Customer, Corporate Affairs													
35	Human Resources	16.0 L35	103	96	103	84	88	84	88	88	88	117	124	124
36	Customer Service	16.0 L36	124	116	121	116	124	154	124	191	124	438	479	479
37	Conservation and Energy Management	16.0 L37	146	137	142	128	114	110	112	112	112	116	116	116
38	Power Acquisitions and Contract Management	16.0 L38	16	22	16	23	23	26	23	28	23	25	26	26
39	Communications and Community Engagement	16.0 L39	93	118	91	98	86	94	86	95	86	105	107	107
40	Regulatory and Rates	16.0 L40	27	26	27	26	28	23	27	26	27	28	28	28
41	Ethics and Merit Office	16.0 L41	2	2	2	2	1	2	1	3	1	4	5	5
42	Smart Metering & Infrastructure	16.0 L42	53	53	0	25	0	0	0	0	0	0	0	0
43	Business Unit Support	16.0 L43	7	2	7	3	3	3	3	3	3	3	3	3
44	Total People, Customer, Corporate Affairs BG	16.0 L44	570	571	508	506	467	497	463	545	463	835	887	887
	Other													
45	Office of the General Counsel	16.0 L45	38	38	38	37	37	36	37	35	37	36	42	42
46	Office of the President and Chief Operating Officer	16.0 L46	2	3	2	3	4	4	4	3	4	3	3	3
47	Site C Project	16.0 L47	158	97	198	109	186	167	189	226	199	322	460	472
48	Independent Power Producer Capital Leases	16.0 L48	0	0	0	0	0	0	0	0	0	0	0	0
49	Corporate Costs	16.0 L49	0	0	0	0	0	0	0	0	0	0	0	0
50	Capitalized Costs	16.0 L50	0	0	0	0	0	0	0	0	0	0	0	0
51	Total Other BG	16.0 L51	199	138	239	149	227	208	231	264	241	361	505	518
52	Total BC Hydro FTEs	16.0 L60	6,389	6,312	6,365	6,234	6,296	6,315	6,344	6,611	6,365	7,161	7,477	7,471
	Production and Financial Summary													
53	Number of customers		1,948,867	1,935,068	1,977,635	1,960,555	1,991,447	1,987,963	2,019,465	2,018,044	2,047,420	2,049,157	2,080,305	2,106,890
54	Domestic Sales (GWh)	14.0 L10	53,130	51,199	53,760	51,023	51,860	51,895	51,838	52,102	52,664	52,413	53,298	53,253
55	Dometic revenues ($ million)	14.0 L22	$4,392.9	$4,177.6	$4,699.2	$4,418.7	$4,710.3	$4,709.7	$4,880.2	$4,895.5	$5,101.6	$5,067.2	$4,918.5	$4,942.4
56	Total revenues ($ million)	1.0 L7+24+29	$4,514.2	$4,312.8	$4,825.8	$4,557.3	$4,847.4	$4,852.8	$5,018.4	$5,039.2	$5,242.2	$5,291.6	$5,494.0	$5,474.1
57	Total costs ($ million)	1.0 (L1:L5)+L8+L12+L16+L19	$3,932.7	$3,732.0	$4,173.9	$3,902.3	$4,163.4	$4,169.2	$4,320.4	$4,355.2	$4,530.2	$5,719.9	$4,782.0	$4,762.1
58	Net Income ($ million)	L56 - L57	$581.5	$580.8	$651.9	$655.0	$684.0	$683.5	$698.0	$684.0	$712.0	($428.2)	$712.0	$712.0

109.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
Exhibit B-1, Section 5.7.4, pp. 5-63–5-65, Table 5-16
Key Business Unit (KBU) benchmarks

On page 5-63 of the Application, BC Hydro states that "[w]hile not all KBUs lend themselves to the use of benchmarks, many KBUs do use benchmarks to help inform management decisions."

1.62.1 For those KBUs that do not use benchmarks, please explain how BC Hydro measures their operational effectiveness including any performance indicators that measure success.

RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

These business plans are regularly reviewed by management and specific measures are included on performance measurement dashboards for each Business Group, which are reviewed monthly.

- **Integrated Planning Business Group**
  - **Safety**
    - **Potential / Actual Serious Incidents (#)**
    - **Lost Time Injury – Employees and Contractors (#)**
    - **Near Misses and Good Catches – Employees (#)**
    - **Near Misses and Good Catches – Contractors (#)**
    - **Return to Work Package Offered Before 1st Doctor's Visit (%)**
  - **Financial**
    - **Total Operating Costs ($)**
    - **Revenue – Interconnections ($)**
    - **Revenue – Shared Assets ($)**
    - **Revenue – Leases ($)**

2.109.1 What criteria does BC Hydro apply to assessing the performance level when examining 'Total Operating Costs' for the Integrated Planning Business Group? Please explain how BC Hydro gauges a positive outcome.

RESPONSE:

A positive outcome for Total Operating Costs for the Integrated Planning Business Group is defined as actual annual expenditures within 97 to 100 per cent of the annual operating plans while completing the related annual KBU work plans such as maintenance activities. This threshold or criteria is set in advance of the fiscal year by senior and executive management.

Performance is measured on a monthly, year to date and annual forecast basis against the criteria, at the Department, KBU, and Business Group levels of the organization.

109.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
Exhibit B-1, Section 5.7.4, pp. 5-63–5-65, Table 5-16
Key Business Unit (KBU) benchmarks

On page 5-63 of the Application, BC Hydro states that "[w]hile not all KBUs lend themselves to the use of benchmarks, many KBUs do use benchmarks to help inform management decisions."

1.62.1 For those KBUs that do not use benchmarks, please explain how BC Hydro measures their operational effectiveness including any performance indicators that measure success.

RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

These business plans are regularly reviewed by management and specific measures are included on performance measurement dashboards for each Business Group, which are reviewed monthly.

- **Integrated Planning Business Group**
  - **Safety**
    - **Potential / Actual Serious Incidents (#)**
    - **Lost Time Injury – Employees and Contractors (#)**
    - **Near Misses and Good Catches – Employees (#)**
    - **Near Misses and Good Catches – Contractors (#)**
    - **Return to Work Package Offered Before 1st Doctor's Visit (%)**
  - **Financial**
    - **Total Operating Costs ($)**
    - **Revenue – Interconnections ($)**
    - **Revenue – Shared Assets ($)**
    - **Revenue – Leases ($)**

2.109.2 Does BC Hydro evaluate 'Total Operating Costs' for the Integrated Business Unit over a specific time period in order to assess performance?

RESPONSE:

This answer also responds to CEC IRs 2.109.2.1 and 2.109.2.2.

The Total Operating Cost metric ($) is an annual metric, measured monthly.

BC Hydro performs evaluations of financial performance for the Integrated Planning Business on a monthly basis, at the Department, KBU, and Business Group level. This includes: comparisons of monthly and year to date results against plan; comparisons against prior year; and in some cases, comparisons against the historical averages.

In addition, comparisons of the current test period to the prior test period are made as part of the revenue requirements process.

109.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
Exhibit B-1, Section 5.7.4, pp. 5-63–5-65, Table 5-16
Key Business Unit (KBU) benchmarks

On page 5-63 of the Application, BC Hydro states that "[w]hile not all KBUs lend themselves to the use of benchmarks, many KBUs do use benchmarks to help inform management decisions."

1.62.1 For those KBUs that do not use benchmarks, please explain how BC Hydro measures their operational effectiveness including any performance indicators that measure success.

RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

These business plans are regularly reviewed by management and specific measures are included on performance measurement dashboards for each Business Group, which are reviewed monthly.

- Integrated Planning Business Group
  - Safety
    - Potential / Actual Serious Incidents (#)
    - Lost Time Injury – Employees and Contractors (#)
    - Near Misses and Good Catches – Employees (#)
    - Near Misses and Good Catches – Contractors (#)
    - Return to Work Package Offered Before 1st Doctor's Visit (%)
  - Financial
    - Total Operating Costs ($)
    - Revenue – Interconnections ($)
    - Revenue – Shared Assets ($)
    - Revenue – Leases ($)

2.109.2 Does BC Hydro evaluate 'Total Operating Costs' for the Integrated Business Unit over a specific time period in order to assess performance?

2.109.2.1 If yes, over what time period?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.109.2 where we describe the time periods for evaluations.

109.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
Exhibit B-1, Section 5.7.4, pp. 5-63–5-65, Table 5-16
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1.62.1 For those KBUs that do not use benchmarks, please explain how BC Hydro measures their operational effectiveness including any performance indicators that measure success.

RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

These business plans are regularly reviewed by management and specific measures are included on performance measurement dashboards for each Business Group, which are reviewed monthly.

- **Integrated Planning Business Group**
  - **Safety**
    - **Potential / Actual Serious Incidents (#)**
    - **Lost Time Injury – Employees and Contractors (#)**
    - **Near Misses and Good Catches – Employees (#)**
    - **Near Misses and Good Catches – Contractors (#)**
    - **Return to Work Package Offered Before 1st Doctor's Visit (%)**
  - **Financial**
    - **Total Operating Costs ($)**
    - **Revenue – Interconnections ($)**
    - **Revenue – Shared Assets ($)**
    - **Revenue – Leases ($)**

2.109.2 Does BC Hydro evaluate 'Total Operating Costs' for the Integrated Business Unit over a specific time period in order to assess performance?

2.109.2.2 If no, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.109.2 where we describe the time periods for evaluations.

109.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
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1.62.1 For those KBUs that do not use benchmarks, please explain how BC Hydro measures their operational effectiveness including any performance indicators that measure success.

RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

These business plans are regularly reviewed by management and specific measures are included on performance measurement dashboards for each Business Group, which are reviewed monthly.

- **Integrated Planning Business Group**
  - **Safety**
    - **Potential / Actual Serious Incidents (#)**
    - **Lost Time Injury – Employees and Contractors (#)**
    - **Near Misses and Good Catches – Employees (#)**
    - **Near Misses and Good Catches – Contractors (#)**
    - **Return to Work Package Offered Before 1st Doctor's Visit (%)**
  - **Financial**
    - **Total Operating Costs ($)**
    - **Revenue – Interconnections ($)**
    - **Revenue – Shared Assets ($)**
    - **Revenue – Leases ($)**

2.109.3 What criteria does BC Hydro apply to assessing the performance level when examining 'Revenue-Interconnections' for the Integrated Planning Business Group? Please explain how BC Hydro gauges a positive or negative outcome.

RESPONSE:

The Revenue-Interconnections performance measure monitors the annual aggregated revenues from load and generator customers' interconnection studies. The performance measure is not used to measure effectiveness – it is a monitoring measure only. A higher revenue value would indicate a higher total number of studies and/or higher dollar value studies being conducted in a fiscal year. By measuring revenues, we are able to match the variances in our operating costs that are offset by the revenues so that there is no negative impact on customer rates. In addition, comparing the year over year results is a key input into forecasting future demand for studies.

109.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
Exhibit B-1, Section 5.7.4, pp. 5-63–5-65, Table 5-16
Key Business Unit (KBU) benchmarks

On page 5-63 of the Application, BC Hydro states that "[w]hile not all KBUs lend themselves to the use of benchmarks, many KBUs do use benchmarks to help inform management decisions."

1.62.1 For those KBUs that do not use benchmarks, please explain how BC Hydro measures their operational effectiveness including any performance indicators that measure success.

RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

These business plans are regularly reviewed by management and specific measures are included on performance measurement dashboards for each Business Group, which are reviewed monthly.

- **Integrated Planning Business Group**
  - **Safety**
    - **Potential / Actual Serious Incidents (#)**
    - **Lost Time Injury – Employees and Contractors (#)**
    - **Near Misses and Good Catches – Employees (#)**
    - **Near Misses and Good Catches – Contractors (#)**
    - **Return to Work Package Offered Before 1st Doctor's Visit (%)**
  - **Financial**
    - **Total Operating Costs ($)**
    - **Revenue – Interconnections ($)**
    - **Revenue – Shared Assets ($)**
    - **Revenue – Leases ($)**

2.109.4 Does BC Hydro evaluate 'Revenue-Interconnections' for the Integrated Business Unit over a specific time period in order to assess performance?

RESPONSE:

This answer also responds to CEC IRs 2.109.4.1 and 2.109.4.2.

The Revenue-Interconnections metric is assessed on a fiscal year basis.

109.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
Exhibit B-1, Section 5.7.4, pp. 5-63–5-65, Table 5-16
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On page 5-63 of the Application, BC Hydro states that "[w]hile not all KBUs lend themselves to the use of benchmarks, many KBUs do use benchmarks to help inform management decisions."

1.62.1 For those KBUs that do not use benchmarks, please explain how BC Hydro measures their operational effectiveness including any performance indicators that measure success.

RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

These business plans are regularly reviewed by management and specific measures are included on performance measurement dashboards for each Business Group, which are reviewed monthly.

- **Integrated Planning Business Group**
  - **Safety**
    - **Potential / Actual Serious Incidents (#)**
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    - **Near Misses and Good Catches – Employees (#)**
    - **Near Misses and Good Catches – Contractors (#)**
    - **Return to Work Package Offered Before 1st Doctor's Visit (%)**
  - **Financial**
    - **Total Operating Costs ($)**
    - **Revenue – Interconnections ($)**
    - **Revenue – Shared Assets ($)**
    - **Revenue – Leases ($)**

2.109.4 Does BC Hydro evaluate 'Revenue-Interconnections' for the Integrated Business Unit over a specific time period in order to assess performance?

2.109.4.1 If yes, over what time period?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.109.4.

109.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
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On page 5-63 of the Application, BC Hydro states that "[w]hile not all KBUs lend themselves to the use of benchmarks, many KBUs do use benchmarks to help inform management decisions."

1.62.1 For those KBUs that do not use benchmarks, please explain how BC Hydro measures their operational effectiveness including any performance indicators that measure success.

RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

These business plans are regularly reviewed by management and specific measures are included on performance measurement dashboards for each Business Group, which are reviewed monthly.

- **Integrated Planning Business Group**
  - **Safety**
    - **Potential / Actual Serious Incidents (#)**
    - **Lost Time Injury – Employees and Contractors (#)**
    - **Near Misses and Good Catches – Employees (#)**
    - **Near Misses and Good Catches – Contractors (#)**
    - **Return to Work Package Offered Before 1st Doctor's Visit (%)**
  - **Financial**
    - **Total Operating Costs ($)**
    - **Revenue – Interconnections ($)**
    - **Revenue – Shared Assets ($)**
    - **Revenue – Leases ($)**

2.109.4 Does BC Hydro evaluate 'Revenue-Interconnections' for the Integrated Business Unit over a specific time period in order to assess performance?

2.109.4.2 If no, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.109.4.

110.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
Exhibit B-1, Section 5.7.4, pp. 5-63–5-65, Table 5-16
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On page 5-63 of the Application, BC Hydro states that "[w]hile not all KBUs lend themselves to the use of benchmarks, many KBUs do use benchmarks to help inform management decisions."

1.62.1 For those KBUs that do not use benchmarks, please explain how BC Hydro measures their operational effectiveness including any performance indicators that measure success.

RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

These business plans are regularly reviewed by management and specific measures are included on performance measurement dashboards for each Business Group, which are reviewed monthly.

- **Reliability**
  - **SAIDI**
  - **SAIFI**
  - **CAIDI**
  - **CEMI – 4**
  - **5-Year Rolling Average Forced Outage Factor Performance (Key Facilities)**
  - **Enterprise Capital Project Write-offs ($)**
  - **Ex-Plan Projects ($)**
  - **Ex-Plan Projects (#)**
  - **Integrated Planning Project Operations and Maintenance ($)**
  - **Interconnections - # / MW of interconnection requests received**
  - **MWh (received)**
  - **Interconnections - # / MW of interconnection projects going into service**
  - **MWh (service)**
  - **Interconnections – Studies completed on time (%)**
  - **Residential – Actual (%)**
  - **Residential - Temp Normalized (%)**
  - **Light Industrial and Commercial (%)**
  - **Large Industrial (%)**
  - **Total Domestic Sales - Actual (%)**
  - **Total Domestic Sales - Temp Normalized (%)**
  - **Phase 3 DC Fast Charging EV Stations in Service (#)**
  - **Headcount Equivalent (HCE) - Active employees only (#)**
  - **Training Hours (excluding safety training) per HCE (Hours)**

2.110.1 Please explain the meaning of Ex-Plan Projects ($), and #, and explain why it is relevant to the measure of reliability.

RESPONSE:

Ex-Plan Projects ($) and (#) were miscategorised in BC Hydro's response to BCUC IR 1.62.1. These metrics are related to Capital Delivery Management and should have been listed under the Service Delivery category.

Ex-Plan Projects ($) refers to the total ex-plan capital additions that have been approved to be included in the capital portfolio. Ex-Plan Projects (#) refers to the number of investments associated with the ex-plan capital additions.

For additional information on the metrics for ex-plan projects, please refer to BC Hydro's response to CEC IR 2.111.1.

110.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
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On page 5-63 of the Application, BC Hydro states that "[w]hile not all KBUs lend themselves to the use of benchmarks, many KBUs do use benchmarks to help inform management decisions."

1.62.1 For those KBUs that do not use benchmarks, please explain how BC Hydro measures their operational effectiveness including any performance indicators that measure success.

RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

These business plans are regularly reviewed by management and specific measures are included on performance measurement dashboards for each Business Group, which are reviewed monthly.

- **Reliability**
  - **SAIDI**
  - **SAIFI**
  - **CAIDI**
  - **CEMI – 4**
  - **5-Year Rolling Average Forced Outage Factor Performance (Key Facilities)**
  - **Enterprise Capital Project Write-offs ($)**
  - **Ex-Plan Projects ($)**
  - **Ex-Plan Projects (#)**
  - **Integrated Planning Project Operations and Maintenance ($)**
  - **Interconnections - # / MW of interconnection requests received**
  - **MWh (received)**
  - **Interconnections - # / MW of interconnection projects going into service**
  - **MWh (service)**
  - **Interconnections – Studies completed on time (%)**
  - **Residential – Actual (%)**
  - **Residential - Temp Normalized (%)**
  - **Light Industrial and Commercial (%)**
  - **Large Industrial (%)**
  - **Total Domestic Sales - Actual (%)**
  - **Total Domestic Sales - Temp Normalized (%)**
  - **Phase 3 DC Fast Charging EV Stations in Service (#)**
  - **Headcount Equivalent (HCE) - Active employees only (#)**
  - **Training Hours (excluding safety training) per HCE (Hours)**

2.110.2 Please explain how these values are gauged by BC Hydro to be a positive or negative outcome.

RESPONSE:

The approval of ex-plan investments is seen as a positive response to addressing emergent needs and the dynamic nature of BC Hydro's Capital Plan. As discussed in section 6.3.5 of Chapter 6 of the Application, ex-plan approvals allow BC Hydro to address emerging issues, advance future investments based on new information or increase funding to existing programs in response to identified needs.

110.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
Exhibit B-1, Section 5.7.4, pp. 5-63–5-65, Table 5-16
Key Business Unit (KBU) benchmarks

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1.62.1 For those KBUs that do not use benchmarks, please explain how BC Hydro measures their operational effectiveness including any performance indicators that measure success.

RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

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- **Reliability**
  - **SAIDI**
  - **SAIFI**
  - **CAIDI**
  - **CEMI – 4**
  - **5-Year Rolling Average Forced Outage Factor Performance (Key Facilities)**
  - **Enterprise Capital Project Write-offs ($)**
  - **Ex-Plan Projects ($)**
  - **Ex-Plan Projects (#)**
  - **Integrated Planning Project Operations and Maintenance ($)**
  - **Interconnections - # / MW of interconnection requests received**
  - **MWh (received)**
  - **Interconnections - # / MW of interconnection projects going into service**
  - **MWh (service)**
  - **Interconnections – Studies completed on time (%)**
  - **Residential – Actual (%)**
  - **Residential - Temp Normalized (%)**
  - **Light Industrial and Commercial (%)**
  - **Large Industrial (%)**
  - **Total Domestic Sales - Actual (%)**
  - **Total Domestic Sales - Temp Normalized (%)**
  - **Phase 3 DC Fast Charging EV Stations in Service (#)**
  - **Headcount Equivalent (HCE) - Active employees only (#)**
  - **Training Hours (excluding safety training) per HCE (Hours)**

2.110.3 Please explain how the Integrated Planning Project Operations and Maintenance ($) are gauged as to performance. Are the costs to be minimized, or are they established to reach targets? Please explain.

RESPONSE:

The Integrated Planning Project Operations and Maintenance budget is established primarily to fund costs incurred in projects after initiation but prior to the identification of a leading alternative solution. These costs are accounted for as operating costs whereas most costs incurred subsequent to the identification of a leading alternative are capitalized.

The allocation of funds to individual projects is done through gate approvals in those projects. The performance of this budget is gauged through our ability to deliver on our capital plan by releasing and progressing projects through these early stages of BC Hydro's capital project lifecycle as planned. In addition, performance is measured through our ability to complete the work within the constraints of the annual budget.

For further details on this budget, please refer to section 5A.10.2.3 of Chapter 5 of the Application. Please also refer to section 6.4.7.5 of Chapter 6 of the Application for further information on BC Hydro's capital project lifecycle.

110.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
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1.62.1 For those KBUs that do not use benchmarks, please explain how BC Hydro measures their operational effectiveness including any performance indicators that measure success.

RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

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- **Reliability**
  - **SAIDI**
  - **SAIFI**
  - **CAIDI**
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  - **Ex-Plan Projects (#)**
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  - **Interconnections - # / MW of interconnection requests received**
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  - **Light Industrial and Commercial (%)**
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  - **Total Domestic Sales - Actual (%)**
  - **Total Domestic Sales - Temp Normalized (%)**
  - **Phase 3 DC Fast Charging EV Stations in Service (#)**
  - **Headcount Equivalent (HCE) - Active employees only (#)**
  - **Training Hours (excluding safety training) per HCE (Hours)**

2.110.4 Are the costs evaluated over time?

RESPONSE:

This answer also responds to CEC IRs 2.110.4.1 and 2.110.4.2.

The Project Operation & Maintenance costs incurred in capital projects are planned, scheduled, monitored and evaluated as part of our project management practice.

At the portfolio level, Project Operations and Maintenance costs are forecast monthly and managed against the annual budget. This annual budget is determined by forecasting the Project Operation and Maintenance expenditures in a given year across the entire portfolio. This portfolio of projects and the associated Project Operations and Maintenance budget varies from year to year, due to project size, complexity, and stage in the project lifecycle. This variability limits the value of year to year comparisons over time.

110.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
Exhibit B-1, Section 5.7.4, pp. 5-63–5-65, Table 5-16
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1.62.1 For those KBUs that do not use benchmarks, please explain how BC Hydro measures their operational effectiveness including any performance indicators that measure success.

RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

These business plans are regularly reviewed by management and specific measures are included on performance measurement dashboards for each Business Group, which are reviewed monthly.

- **Reliability**
  - **SAIDI**
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  - **Enterprise Capital Project Write-offs ($)**
  - **Ex-Plan Projects ($)**
  - **Ex-Plan Projects (#)**
  - **Integrated Planning Project Operations and Maintenance ($)**
  - **Interconnections - # / MW of interconnection requests received**
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  - **MWh (service)**
  - **Interconnections – Studies completed on time (%)**
  - **Residential – Actual (%)**
  - **Residential - Temp Normalized (%)**
  - **Light Industrial and Commercial (%)**
  - **Large Industrial (%)**
  - **Total Domestic Sales - Actual (%)**
  - **Total Domestic Sales - Temp Normalized (%)**
  - **Phase 3 DC Fast Charging EV Stations in Service (#)**
  - **Headcount Equivalent (HCE) - Active employees only (#)**
  - **Training Hours (excluding safety training) per HCE (Hours)**

2.110.4 Are the costs evaluated over time?

2.110.4.1 If yes, over what time period?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.110.4, where we explain that the Integrated Planning Project Operations and Maintenance budget is an annual budget for which a monthly forecast is prepared.

110.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
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1.62.1 For those KBUs that do not use benchmarks, please explain how BC Hydro measures their operational effectiveness including any performance indicators that measure success.

RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

These business plans are regularly reviewed by management and specific measures are included on performance measurement dashboards for each Business Group, which are reviewed monthly.

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  - **Enterprise Capital Project Write-offs ($)**
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  - **Ex-Plan Projects (#)**
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  - **Phase 3 DC Fast Charging EV Stations in Service (#)**
  - **Headcount Equivalent (HCE) - Active employees only (#)**
  - **Training Hours (excluding safety training) per HCE (Hours)**

2.110.4 Are the costs evaluated over time?

2.110.4.2 If no, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.110.4 where we explain how these costs are evaluated over time.

111.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
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RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

These business plans are regularly reviewed by management and specific measures are included on performance measurement dashboards for each Business Group, which are reviewed monthly.

- **Business Plan – Focus Area 1 – Improve affordability through better portfolio investment optimization**
  - **Enterprise Capital Project Write-offs ($)**
  - **Ex-Plan Projects (# / $)**
  - **Variance between capital forecast and plan in the 2 year horizon (%)**

2.111.1 Please explain the criteria BC Hydro uses to assess the performance level for the Ex Plan Project (#/$).

RESPONSE:

As discussed in BC Hydro's response to CEC IR 2.110.1, ex-plan investments are tracked based on the number of investments approved as well as the total capital additions of the ex-plan approvals. These metrics are tracked to understand the degree of change to the portfolio versus the approved capital plan. These metrics trigger periodic reviews to confirm the ex-plan governance and identify any trends in ex-plan investments that should be considered in future annual enterprise capital planning processes.

Please refer to BC Hydro's response to BCUC IR 1.110.1 where we explain what constitutes an ex-plan investment and to BC Hydro's response to BCUC IR 2.254.3 where we explain the governance for ex-plan investments.

111.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
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RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

These business plans are regularly reviewed by management and specific measures are included on performance measurement dashboards for each Business Group, which are reviewed monthly.

- **Business Plan – Focus Area 1 – Improve affordability through better portfolio investment optimization**
  - **Enterprise Capital Project Write-offs ($)**
  - **Ex-Plan Projects (# / $)**
  - **Variance between capital forecast and plan in the 2 year horizon (%)**

2.111.2 Please explain how BC Hydro gauges a positive or negative outcome with regard to improving affordability through better portfolio investment optimization.

RESPONSE:

BC Hydro has defined the desired outcome of this focus area as increased value and transparency of our asset investment decisions and improving our capability to define a portfolio of the right investments at the right time. BC Hydro uses multiple aspects of the Enterprise Capital Planning process described in section 6.3 of Chapter 6 of the Application so that capital investments are appropriately timed to balance affordability, system performance and risk.

By monitoring the metrics referenced in the preamble to the question and taking any required actions, we expect to gain the following more specific positive outcomes:

- **Enterprise Capital Project Write-offs ($): This metric reflects making appropriate decisions on projects as they move through their lifecycle. When BC Hydro detects an increasing trend to project write-offs, we conduct reviews and identify capital planning and delivery process improvements. Please refer to section 8.11 of Chapter 8 of the Application where we explain that these decisions reflect mature portfolio management practices.**
- **Ex-Plan Projects (# / $): This metric reflects responding to emerging needs. Please refer to BC Hydro's response to CEC IR 2.111.1 where we explain the possible actions BC Hydro may take as a result of monitoring this metric.**
- **Variance between capital forecast and plan in the two-year horizon (%): This metric reflects monitoring changes to forecast and managing within our approved capital budgets by actively addressing emergent needs and the dynamic nature of BC Hydro's Capital Plan through advancements and deferrals.**

An additional key component of the focus area is the Asset Investment Planning tool project (refer to line 27 on page 9 of Appendix I of the Application). Please refer to BC Hydro's response to CEC IR 1.4.2 for further information on this project and other improvements to our asset management and capital planning processes.

111.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
Exhibit B-1, Section 5.7.4, pp. 5-63–5-65, Table 5-16
Key Business Unit (KBU) benchmarks

On page 5-63 of the Application, BC Hydro states that "[w]hile not all KBUs lend themselves to the use of benchmarks, many KBUs do use benchmarks to help inform management decisions."

1.62.1 For those KBUs that do not use benchmarks, please explain how BC Hydro measures their operational effectiveness including any performance indicators that measure success.

RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

These business plans are regularly reviewed by management and specific measures are included on performance measurement dashboards for each Business Group, which are reviewed monthly.

- **Business Plan – Focus Area 1 – Improve affordability through better portfolio investment optimization**
  - **Enterprise Capital Project Write-offs ($)**
  - **Ex-Plan Projects (# / $)**
  - **Variance between capital forecast and plan in the 2 year horizon (%)**

2.111.3 Please explain if BC Hydro evaluates the factor over a specific time period in order to assess performance?

RESPONSE:

These metrics are monitored for informational purposes on an ongoing basis to determine any trends that may require investigation or action. Please refer to BC Hydro's response to CEC IR 2.111.2 where we explain why BC Hydro monitors these metrics and possible actions that may be undertaken as a result.

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111.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
Exhibit B-1, Section 5.7.4, pp. 5-63–5-65, Table 5-16
Key Business Unit (KBU) benchmarks

On page 5-63 of the Application, BC Hydro states that "[w]hile not all KBUs lend themselves to the use of benchmarks, many KBUs do use benchmarks to help inform management decisions."

1.62.1 For those KBUs that do not use benchmarks, please explain how BC Hydro measures their operational effectiveness including any performance indicators that measure success.

RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

These business plans are regularly reviewed by management and specific measures are included on performance measurement dashboards for each Business Group, which are reviewed monthly.

- **Business Plan – Focus Area 1 – Improve affordability through better portfolio investment optimization**
  - **Enterprise Capital Project Write-offs ($)**
  - **Ex-Plan Projects (# / $)**
  - **Variance between capital forecast and plan in the 2 year horizon (%)**

2.111.3 Please explain if BC Hydro evaluates the factor over a specific time period in order to assess performance?

2.111.3.1 If yes, over what time period and how is it evaluated?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.111.3 where we state that BC Hydro monitors these metrics on an ongoing basis to identify any trends that may require investigation or action.

111.0 Reference: Exhibit B-5, BCUC 1.62.1

62.0 E. CHAPTER 5 – OPERATING COSTS

Reference: OPERATING COSTS
Exhibit B-1, Section 5.7.4, pp. 5-63–5-65, Table 5-16
Key Business Unit (KBU) benchmarks

On page 5-63 of the Application, BC Hydro states that "[w]hile not all KBUs lend themselves to the use of benchmarks, many KBUs do use benchmarks to help inform management decisions."

1.62.1 For those KBUs that do not use benchmarks, please explain how BC Hydro measures their operational effectiveness including any performance indicators that measure success.

RESPONSE:

All Business Groups and Key Business Units develop annual business plans that identify key activities that each KBU will focus on during the year as well as metrics to measure performance.

These business plans are regularly reviewed by management and specific measures are included on performance measurement dashboards for each Business Group, which are reviewed monthly.

- **Business Plan – Focus Area 1 – Improve affordability through better portfolio investment optimization**
  - **Enterprise Capital Project Write-offs ($)**
  - **Ex-Plan Projects (# / $)**
  - **Variance between capital forecast and plan in the 2 year horizon (%)**

2.111.3 Please explain if BC Hydro evaluates the factor over a specific time period in order to assess performance?

2.111.3.2 If no, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.111.3 where we explain that BC Hydro intends to monitor these metrics on an ongoing basis to identify any trends that may require investigation or action.

112.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Business Plan – Focus Area 2 – Develop more dynamic energy planning**
  - **Number of planning improvement projects complete (#)**
  - **Weather normalized forecasts to actual (% reduction in delta)**
  - **Overall reduction in effort to produce load forecasts (hours)**

2.112.1 Please explain BC Hydro's definition of 'more dynamic energy planning'.

RESPONSE:

More dynamic energy planning is a broad goal describing the desired outcome of the Dynamic Energy Planning program. Dynamic Energy Planning is a program focused on the improvement of BC Hydro's overall capability to forecast and plan for uncertainty and change with regards to how energy and capacity needs are met.

For example, the program is advancing improvements to normalizing peak demand to annual weather to address the recent historical gap between forecasted peaks and actual peaks, with the goal of achieving a closer correlation.

Ultimately, the program will improve planning capabilities, information and processes to further enable system planners to focus BC Hydro capital investment where and when it is needed most.

112.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Business Plan – Focus Area 2 – Develop more dynamic energy planning**
  - **Number of planning improvement projects complete (#)**
  - **Weather normalized forecasts to actual (% reduction in delta)**
  - **Overall reduction in effort to produce load forecasts (hours)**

2.112.2 Please confirm that a large and effective planning improvement project can potentially have more valuable outcomes than multiple small or less effective projects?

RESPONSE:

Whether a large improvement project would have more valuable outcomes than multiple small projects depends on the specific circumstances in each instance.

In this case, Dynamic Energy Planning is a program that consists of a series of projects, ranging in size, that are being coordinated to ensure alignment and efficient delivery. Through this coordination, the program balances benefits versus effort and prioritizes the highest overall value initiatives.

The intent of the measure tracking the number of improvement projects delivered is to understand the progress of the defined program scope over the course of the year.

112.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Business Plan – Focus Area 2 – Develop more dynamic energy planning**
  - **Number of planning improvement projects complete (#)**
  - **Weather normalized forecasts to actual (% reduction in delta)**
  - **Overall reduction in effort to produce load forecasts (hours)**

2.112.2 Please confirm that a large and effective planning improvement project can potentially have more valuable outcomes than multiple small or less effective projects?

2.112.2.1 If no, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.112.2.

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112.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Business Plan – Focus Area 2 – Develop more dynamic energy planning**
  - **Number of planning improvement projects complete (#)**
  - **Weather normalized forecasts to actual (% reduction in delta)**
  - **Overall reduction in effort to produce load forecasts (hours)**

2.112.3 How does BC Hydro assess the quality of the planning improvement projects?

RESPONSE:

For Dynamic Energy Planning, the quality of planning improvement projects is assessed by examining the outcomes, the effort engaged and the effects on BC Hydro's ability to plan and/or forecast. The latter requires the passage of time to compare future actuals to current forecasts.

The quality of the projects themselves is regularly reviewed as part of the program delivery process. For example, BC Hydro tracks progress on the overall program and its individual work elements and regular meetings and internal reviews are held to assess the projects as they progress.

112.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Business Plan – Focus Area 2 – Develop more dynamic energy planning**
  - **Number of planning improvement projects complete (#)**
  - **Weather normalized forecasts to actual (% reduction in delta)**
  - **Overall reduction in effort to produce load forecasts (hours)**

2.112.4 For each item, please explain if BC Hydro evaluates the factor over a specific time period in order to assess performance?

RESPONSE:

This answer also responds to CEC IRs 2.112.4.1 and 2.112.4.2.

Yes, BC Hydro evaluates the Dynamic Energy Planning metrics over specific time periods. Specifically:

- **Number of planning improvement projects complete (#) – this metric tracks the actual number of completed initiatives within the Dynamic Energy Planning program. Initiatives are selected based on a prioritization approach and the total volume of completed projects is a reasonable measure for the planned completion of the defined program scope. The time period of evaluation is over fiscal 2020.**
- **Weather normalized forecasts to actual (% reduction in delta) – this metric is assessed by the difference between weather normalized forecasts and actual results. The goal is a reduction in the delta which would demonstrate an improved ability to plan while still accounting for regular seasonal changes in temperature. The evaluation is ongoing, with a review each fiscal year.**
- **Overall reduction in effort to produce load forecasts (hours) – this metric is assessed by the reduction in total effort (in working hours) to produce load forecasts by improving the efficiency by which they are produced. The time period for evaluation is over fiscal 2020, with ongoing review as part of the load forecast process.**

112.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Business Plan – Focus Area 2 – Develop more dynamic energy planning**
  - **Number of planning improvement projects complete (#)**
  - **Weather normalized forecasts to actual (% reduction in delta)**
  - **Overall reduction in effort to produce load forecasts (hours)**

2.112.4 For each item, please explain if BC Hydro evaluates the factor over a specific time period in order to assess performance?

2.112.4.1 If yes, over what time period and how is it evaluated?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.112.4 where we discuss how and over what time periods the metrics for Dynamic Energy Planning are evaluated.

112.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Business Plan – Focus Area 2 – Develop more dynamic energy planning**
  - **Number of planning improvement projects complete (#)**
  - **Weather normalized forecasts to actual (% reduction in delta)**
  - **Overall reduction in effort to produce load forecasts (hours)**

2.112.4 For each item, please explain if BC Hydro evaluates the factor over a specific time period in order to assess performance?

2.112.4.2 If no, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.112.4 where we discuss how and over what time periods the metrics for Dynamic Energy Planning are evaluated.

113.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Capital Infrastructure Project Delivery Business Group (CIPD)**

- **Projects**
  - **Performance against First Full Funding Cost: Projects ≤ Target (% and #)**
  - **Performance against First Full Funding Schedule: Projects ≤ Target (% and #)**
  - **Capital Additions all CIPD ($)**
  - **Capital Project Write-offs all CIPD ($)**

2.113.1 Please explain how BC Hydro gauges the value of the projects delivered over time.

RESPONSE:

The measures identified in the preamble to the question are used to gauge the performance of the delivery of projects managed by the Capital Infrastructure Project Delivery Business Group. These measures do not directly gauge the value of projects over time, but measure cost and schedule performance, as well as track capital additions and project write-offs.

The value of projects, or the business benefits achieved from projects, is realized over time through the operation of the asset(s) that a project delivered. The business benefits of these assets delivered by projects over time are measured through the various performance measures (e.g., reliability measures such as SAIFI and SAIDI) that are tracked and updated annually in our Service Plan. Further information on BC Hydro's Service Plan goals and strategies is provided in Appendix E of the Application.

For individual projects, the Project Completion and Evaluation Report (PCER) is used to document how the project was successfully delivered, addressed the scope and achieved, or is expected to achieve, the defined benefits of the project.

114.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Finance, Technology, Supply Chain Business Group**

  - **Supply Chain**
    - **Capital ($) - Supply Chain**
    - **Operating Costs ($) - Supply Chain**
    - **Backlog of Purchasing Service & Materials Requests (#)**
    - **Invoices Paid on Time (%)**

2.114.1 Does BC Hydro calculate an operating cost/$ capital which it evaluates?

RESPONSE:

BC Hydro does not believe an operating cost/$ capital metric would be useful given the majority of the Supply Chain KBU's capital relates to fleet assets and there is very little correlation between these costs and the Supply Chain KBU's total operating costs which include the Materials Management, Procurement and Fleet Services Departments.

This metric would also not be useful even if only applied to the Fleet Services Department as there are many other factors that impact operating costs in that Department, such as fuel prices, insurance rates, age of vehicles, etc., that are not directly related to the value of assets.

114.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Finance, Technology, Supply Chain Business Group**

► **Supply Chain**

- **Capital ($) - Supply Chain**
- **Operating Costs ($) - Supply Chain**
- **Backlog of Purchasing Service & Materials Requests (#)**
- **Invoices Paid on Time (%)**

2.114.1 Does BC Hydro calculate an operating cost/$ capital which it evaluates?

2.114.1.1 If yes, please provide the values as to how BC Hydro gauges the performance.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.114.1.

114.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Finance, Technology, Supply Chain Business Group**

- **Supply Chain**
  - **Capital ($) - Supply Chain**
  - **Operating Costs ($) - Supply Chain**
  - **Backlog of Purchasing Service & Materials Requests (#)**
  - **Invoices Paid on Time (%)**

2.114.1 Does BC Hydro calculate an operating cost/$ capital which it evaluates?

2.114.1.2 Does BC Hydro evaluate performance for these metrics over time?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.114.1.

114.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Finance, Technology, Supply Chain Business Group**

  - **Supply Chain**
    - **Capital ($) - Supply Chain**
    - **Operating Costs ($) - Supply Chain**
    - **Backlog of Purchasing Service & Materials Requests (#)**
    - **Invoices Paid on Time (%)**

2.114.1 Does BC Hydro calculate an operating cost/$ capital which it evaluates?

2.114.1.3 If yes, over what period of time and how is it evaluated.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.114.1.

114.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Finance, Technology, Supply Chain Business Group**

▶ **Supply Chain**

- **Capital ($) - Supply Chain**
- **Operating Costs ($) - Supply Chain**
- **Backlog of Purchasing Service & Materials Requests (#)**
- **Invoices Paid on Time (%)**

2.114.1 Does BC Hydro calculate an operating cost/$ capital which it evaluates?

2.114.1.4 If no, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.114.1.

115.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Finance, Technology, Supply Chain Business Group**

  - **Objective 1: Deliver a successful Fiscal 2020 – Fiscal 2021 Revenue Requirements Application and proceedings**

- **People, Customer, Corporate Affairs Business Group**

  - **Focus Area 1: Deliver a successful F2020-F2021 Revenue Requirements Application and proceeding**

2.115.1 Please provide BC Hydro's definition of delivering a 'successful Fiscal 2020-Fiscal 2021 Revenue Requirements Application and proceeding' for both Business Groups, and explain why they differ, if at all.

RESPONSE:

BC Hydro would consider the Application to be successful if our requests are approved and if our evidence is provided in a clear, open and transparent manner. This does not differ across Business Groups.

116.0 Reference: Exhibit B-5, BCUC 1.62.1

- **People, Customer, Corporate Affairs Business Group**
  - **Power Acquisitions and Contract Management**
    - **IPPs: Actual Energy Purchased (GWh)**

2.116.1 How does BC Hydro assess performance for 'IPPs: Actual Energy Purchased (GWh)'? Does BC Hydro seek to meet a particular value, or consider a higher number of GWh as superior to a lower number of GWh? Please explain.

RESPONSE:

"IPPs: Actual Energy Purchased (GWh)" is used in combination with other metrics to evaluate IPP deliveries. For example, total payments to IPPs ($) is combined with actual energy purchased (GWh) in a given year to calculate the average unit cost of purchased energy. All else being equal, a lower unit cost of purchased energy is considered more favourable than a higher unit cost of delivered energy.

117.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Capital Infrastructure Project Delivery Business Group (CIPD)**

▶ **Indigenous Commitments**

- **Indigenous Commitments (Procurement Contracts with First Nations) ($)**

2.117.1 Please provide the metric by which BC Hydro gauges the effectiveness of Indigenous Commitments. Does a larger dollar commitment equate to greater success? Please explain.

RESPONSE:

The Indigenous Commitments (Procurement Contracts with First Nations) performance measure is used to monitor the annual aggregate value of contracts awarded to First Nation businesses. For Capital Infrastructure Project Delivery reporting, the metric is the total year to date dollar value of contracts awarded. This is a monitoring metric only and no annual target is prepared.

A larger dollar commitment would equate to a greater total value of contracts that have been awarded over the year to date.

On an overall basis, any evaluation of the effectiveness of Indigenous Commitments would include an assessment of contractor performance. For a discussion on how BC Hydro assesses contractor performance, please refer to BC Hydro's response to CEC IR 2.117.2.

117.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Capital Infrastructure Project Delivery Business Group (CIPD)**

▶ **Indigenous Commitments**

- **Indigenous Commitments (Procurement Contracts with First Nations) ($)**

2.117.2 How does BC Hydro evaluate the success of the procurement contracts?

RESPONSE:

BC Hydro evaluates the success of procurement contracts with First Nation businesses using the same performance metrics as contracts with non-Indigenous businesses. Specifically, BC Hydro evaluates whether the contractor meets all commercial terms in the contract, including price, schedule, scope of work and quality as well as whether the contractor meets safety and environmental performance requirements.

118.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Capital Infrastructure Project Delivery Business Group (CIPD)**

- **Focus Area 1: Improve how we deliver projects to address increasingly complex requirements**
  - **Project Budget to Actual Cost: Cumulative 5-years (± 5%)**
  - **Major project delays due to inadequate consultation or First Nations issues (greater than $50M)**
  - **Property rights acquisition for capital projects - Level 1 delays**
  - **Integration frameworks that support reconciliation (#)**
- **Focus Area 2: Implement our environmental strategy and statement of principles**
  - **Number of employee ideas received using online feedback mechanism**

2.118.1 What incentives exist for BC Hydro to minimize the Project Budget at the outset? Please explain.

RESPONSE:

BC Hydro follows Project and Portfolio Management practices (discussed further in section 6.4.7 of Chapter 6 of the Application) so that project budgets are developed based on standardized and rigorous estimating procedures and reflect the best information available with regards to the work required to meet business needs and objectives through the project.

Specifically, project budgets:

- **Are developed based on project specific-information including design reports, user requirements, scope notes, statements of objectives, project risks, work package agreements, constructability reports and reviews, and procurement strategies;**
- **Incorporate lessons learned from past projects; and**
- **Are refined at various stages through the project lifecycle.**

Project scope is tested so that the appropriate scope is undertaken and opportunities for efficiencies are identified. Project cost forecasts are also updated regularly and opportunities for cost savings are incorporated as projects progress through the project lifecycle.

118.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Capital Infrastructure Project Delivery Business Group (CIPD)**

- **Focus Area 1: Improve how we deliver projects to address increasingly complex requirements**
  - **Project Budget to Actual Cost: Cumulative 5-years (± 5%)**
  - **Major project delays due to inadequate consultation or First Nations issues (greater than $50M)**
  - **Property rights acquisition for capital projects - Level 1 delays**
  - **Integration frameworks that support reconciliation (#)**
- **Focus Area 2: Implement our environmental strategy and statement of principles**
  - **Number of employee ideas received using online feedback mechanism**

2.118.2 What is a Level 1 delay?

RESPONSE:

A level 1 delay is a delay that is expected to result in the in-service date of the capital project being missed.

119.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Focus Area 3: Expand the ergonomics program within Operations**
  - **Warm up participation rate by workers (%)**
  - **Ergonomic related injury reduction (calculated quarterly) (YTD) (%)**

2.119.1 Does BC Hydro track the costs of the ergonomics program against the reduction in injuries? Please explain.

RESPONSE:

BC Hydro tracks costs of the ergonomics program, which includes training to build the worker's body mechanics knowledge and prepare the body for work; warm up exercises; assignment and training of leaders within crews to champion and maintain the program; follow-up support calls; and worker participation in identification, assessment and control of ergonomics hazards specific to their work.

As stated in BC Hydro's response to BCUC IR 2.242.1, the initiative to expand and implement the ergonomics program is expected to cost $1.6 million. The program costs are tracked against both the incident reduction data and leading indicator targets such as warm up participation rate, and ergonomic control measures identified, to understand how well the program is functioning and identify gross and net cost savings.

The Ergonomics Program is targeting an overall annual reduction in ergonomics-related injuries of 50 per cent by fiscal 2023 (i.e., a reduction from the current average of 80 ergonomic-related injuries per year to 40 ergonomic-related injuries per year).

120.0 Reference: Exhibit B-5, BCUC 1.62.1

- **Operations Business Group**

▸ **Technology**

- **Capital ($) - Technology**
- **Operating Costs ($) - Technology**
- **Number of Priority 1 Incidents (High Business Impact) (#)**
- **Business Impact Due to Priority 1 & 2 Incidents (Mins)**
- **External Customer Service Impact Due to Priority 1 & 2 Incidents (Mins)**

- **Project Delivery - % Business Requirements Met for closed projects (YTD reported quarterly) (%)**
- **Project Implementation Cost Met - % closed projects within budget (YTD reported quarterly) (%)**
- **Project Implementation Schedule Met - % closed projects with in-service date met (YTD reported quarterly) (%)**

2.120.1 How does BC Hydro evaluate performance for the metric ‘Capital ($) – Technology’?

RESPONSE:

BC Hydro evaluates the performance for the metric ‘Capital ($) – Technology’ using a threshold of +/- 7.5 per cent. The metric is considered green (on track) if the variance between the actual capital spend versus the planned capital spend for a given period is less than or equal to +/- 7.5 per cent. The metric is considered red (off-track) if the variance between the actual capital spend versus the planned capital spend for a given period is more than +/- 7.5 per cent.

121.0 Reference: Exhibit B-6, CEC 1.42.4

1.42.4 Please describe the types of impacts that could occur over the long term as a result of embedded error in the load forecasts.

RESPONSE:

In general, sustained demand that is significantly higher than forecasted would increase the risk that BC Hydro could not adequately or reliably serve customers while significantly lower than expected demand would increase the risk of acquiring or developing supply resources that are not needed or not needed when put into service.

In order to mitigate the risk of these types of impacts, BC Hydro's load forecast methodologies are continually reviewed and refined and load forecasts are typically refreshed on an annual basis in order to ensure current information is used for planning purposes.

2.121.1 Please confirm that the acquisition of unneeded resources or supply by BC Hydro can result in unnecessary cost increases, and price burdens on ratepayers which potentially can have long lasting effects on the economics of BC Hydro's business.

RESPONSE:

BC Hydro, through long term planning processes, assesses how best to meet future customer load while balancing the risks of both over supply and under supply. Over supply can lead to unnecessary cost increases, while under supply can impact reliability. Through our long-term planning, we assess uncertainties using structured decision making to provide a cost-effective resource plan. We update our plans regularly to ensure we are responsive to changing conditions. Please refer to BC Hydro's response to CEC IR 1.41.1 which notes how our long-term strategies are assessed through regular updates and reviews.

BC Hydro also notes that generation, transmission, or other resources can provide multiple benefits in addition to meeting incremental load growth. These include increased safety, reliability, and operational benefits. Additionally, even though uncertainty around demand growth and the lead times associated with resource development may result in misalignment between the resource acquisition and demand in the near-term, the long-term benefits of resource may outweigh short-term costs.

BC Hydro believes that the full array of the life cycle benefits of a resource, not limited to providing capacity for meeting increased demand, needs to be considered in evaluating the economics of a resource.

121.0 Reference: Exhibit B-6, CEC 1.42.4

1.42.4 Please describe the types of impacts that could occur over the long term as a result of embedded error in the load forecasts.

RESPONSE:

In general, sustained demand that is significantly higher than forecasted would increase the risk that BC Hydro could not adequately or reliably serve customers while significantly lower than expected demand would increase the risk of acquiring or developing supply resources that are not needed or not needed when put into service.

In order to mitigate the risk of these types of impacts, BC Hydro's load forecast methodologies are continually reviewed and refined and load forecasts are typically refreshed on an annual basis in order to ensure current information is used for planning purposes.

2.121.2 If not, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.121.1.

122.0 Reference: Exhibit B-6, CEC 1.45.5 and 1.45.7

1.45.5 How often does BC Hydro expect to be assessed, and when is BC Hydro's next assessment scheduled?

RESPONSE:

BC Hydro has not defined a regular assessment frequency for the Project Management Institute's Organizational Project Management Maturity Model.

Our last assessment was in 2016. At this time, BC Hydro has not planned for another assessment, given the positive outcomes of the most recent assessment (i.e., a maturity rating of 91 per cent out of a possible 100 per cent).

1.45.7 Please provide the quantitative data submitted for the evaluation that demonstrated success or lack of success in project management.

RESPONSE:

BC Hydro did not submit quantitative data to demonstrate the success or lack of success of project management outcomes. The Organizational Project Management Maturity Model is a set of international best practices from the Project Management Institute that is used to assess the maturity of Organizational Project Management practices (i.e. not outcomes).

The collection of data used in the Project Management Institute's Organizational Project Management Maturity Model assessment was based on a series of interviews with representatives from the following areas in the organization: Project managers, Program managers, Portfolio managers, Project Management Process and Practice Owners, Program Management Process and Practice Owners, Portfolio Management Process and Practice Owners, PPM Governance Leadership Team, Training Manager, Community of Practice, and PPM Practice Conformance. Where data or reports were shown to the assessor during interviews it was to demonstrate that a particular practice was in existence.

The assessment evaluated the maturity of the PPM system as described in Section 6.4.7 of the Application.

2.122.1 Please provide an explanation as to the value of understanding Project Management 'maturity' if outcomes are not evaluated.

RESPONSE:

The value of the Organizational Project Management Maturity Model Assessment is that it provides a benchmark of BC Hydro's Project Delivery processes against

industry best practice. It provides recommendations specific to BC Hydro, identifying opportunities to increase maturity of processes that will influence the improvement of the delivery of our capital plan.

BC Hydro also assesses its Project Delivery outcomes. For example, as discussed in section 6.2.1.2 of Chapter 6 of the Application, BC Hydro’s Service Plan includes a metric to compare the actual project costs for in-service projects to the Original Approved Expected Cost, in aggregate, over a five-year period.

122.0 Reference: Exhibit B-6, CEC 1.45.5 and 1.45.7

1.45.5 How often does BC Hydro expect to be assessed, and when is BC Hydro's next assessment scheduled?

RESPONSE:

BC Hydro has not defined a regular assessment frequency for the Project Management Institute's Organizational Project Management Maturity Model.

Our last assessment was in 2016. At this time, BC Hydro has not planned for another assessment, given the positive outcomes of the most recent assessment (i.e., a maturity rating of 91 per cent out of a possible 100 per cent).

1.45.7 Please provide the quantitative data submitted for the evaluation that demonstrated success or lack of success in project management.

RESPONSE:

BC Hydro did not submit quantitative data to demonstrate the success or lack of success of project management outcomes. The Organizational Project Management Maturity Model is a set of international best practices from the Project Management Institute that is used to assess the maturity of Organizational Project Management practices (i.e. not outcomes).

The collection of data used in the Project Management Institute's Organizational Project Management Maturity Model assessment was based on a series of interviews with representatives from the following areas in the organization: Project managers, Program managers, Portfolio managers, Project Management Process and Practice Owners, Program Management Process and Practice Owners, Portfolio Management Process and Practice Owners, PPM Governance Leadership Team, Training Manager, Community of Practice, and PPM Practice Conformance. Where data or reports were shown to the assessor during interviews it was to demonstrate that a particular practice was in existence.

The assessment evaluated the maturity of the PPM system as described in Section 6.4.7 of the Application.

2.122.2 Does BC Hydro have any plans to have its Project Management assessed based on outcomes or other criteria using quantitative data? P lease explain why or why not.

RESPONSE:

As discussed in BC Hydro's response to CEC IR 2.122.1, BC Hydro does assess its project delivery processes and performance-based on outcomes.

122.0 Reference: Exhibit B-6, CEC 1.45.5 and 1.45.7

1.45.5 How often does BC Hydro expect to be assessed, and when is BC Hydro's next assessment scheduled?

RESPONSE:

BC Hydro has not defined a regular assessment frequency for the Project Management Institute's Organizational Project Management Maturity Model.

Our last assessment was in 2016. At this time, BC Hydro has not planned for another assessment, given the positive outcomes of the most recent assessment (i.e., a maturity rating of 91 per cent out of a possible 100 per cent).

1.45.7 Please provide the quantitative data submitted for the evaluation that demonstrated success or lack of success in project management.

RESPONSE:

BC Hydro did not submit quantitative data to demonstrate the success or lack of success of project management outcomes. The Organizational Project Management Maturity Model is a set of international best practices from the Project Management Institute that is used to assess the maturity of Organizational Project Management practices (i.e. not outcomes).

The collection of data used in the Project Management Institute's Organizational Project Management Maturity Model assessment was based on a series of interviews with representatives from the following areas in the organization: Project managers, Program managers, Portfolio managers, Project Management Process and Practice Owners, Program Management Process and Practice Owners, Portfolio Management Process and Practice Owners, PPM Governance Leadership Team, Training Manager, Community of Practice, and PPM Practice Conformance. Where data or reports were shown to the assessor during interviews it was to demonstrate that a particular practice was in existence.

The assessment evaluated the maturity of the PPM system as described in Section 6.4.7 of the Application.

2.122.2 Does BC Hydro have any plans to have its Project Management assessed based on outcomes or other criteria using quantitative data? P lease explain why or why not.

2.122.2.1 If yes, what Project Management assessment does BC Hydro expect to use, and why?

RESPONSE:

As discussed in BC Hydro's response to CEC IR 2.122.1, BC Hydro does assess its project delivery processes and performance based on outcomes.

123.0 Reference: Exhibit B-6, CEC 1.52.1 and 1.52.4

1.52.1 Please provide quantification for the savings from the theft reduction from marijuana grow ops in $ and GWh.

RESPONSE:

In the Smart Metering and Infrastructure Program Completion and Evaluation Report submitted in 2016, BC Hydro estimated the savings from theft reduction from marijuana grow-ops to be approximately 675 GWh annually by fiscal 2016.

BC Hydro estimated the smart meter benefits for fiscal 2019 from grow-op theft reduction to be $53 million.

While we have not done a formal assessment since fiscal 2016, we still believe this estimate is valid. BC Hydro's proactive Revenue Assurance program has been successful in preventing a recurrence of marijuana grow-op theft and it is possible that the theft savings could be higher than the previous estimate.

1.52.4 How does BC Hydro measure the cost effectiveness of its Revenue Assurance and Field Inspection Teams? Please provide the metrics used.

RESPONSE:

BC Hydro assesses the value of the Revenue Assurance program relative to the deterrent effect of preventing a return to large scale theft. Since fiscal 2016, the

proportion of grow-ops found to be engaged in theft has consistently been below 5 per cent as compared to over 60 per cent prior to the initiation of BC Hydro's enhanced Revenue Assurance program.

The Revenue Assurance program also includes investigating and resolving overloaded services, customer access and employee safety concerns, and complex metering and billing errors.

2.123.1 How does BC Hydro distinguish between results from its ongoing Revenue Assurance program and the Smart Meter initiative?

RESPONSE:

BC Hydro does not distinguish between results from its ongoing Revenue Assurance program and the Smart Metering and Infrastructure program (SMI).

Through SMI, BC Hydro implemented a comprehensive theft detection solution comprised of Distribution System Metering, Analytics, and enhanced Field Inspection processes and technology. The Revenue Assurance team incorporates all aspects of this solution.

Commercial Energy Consumers Association of British Columbia Information Request No. **2.123.2** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 2
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

123.0 Reference: Exhibit B-6, CEC 1.52.1 and 1.52.4

1.52.1 Please provide quantification for the savings from the theft reduction from marijuana grow ops in $ and GWh.

RESPONSE:

In the Smart Metering and Infrastructure Program Completion and Evaluation Report submitted in 2016, BC Hydro estimated the savings from theft reduction from marijuana grow-ops to be approximately 675 GWh annually by fiscal 2016.

BC Hydro estimated the smart meter benefits for fiscal 2019 from grow-op theft reduction to be $53 million.

While we have not done a formal assessment since fiscal 2016, we still believe this estimate is valid. BC Hydro's proactive Revenue Assurance program has been successful in preventing a recurrence of marijuana grow-op theft and it is possible that the theft savings could be higher than the previous estimate.

1.52.4 How does BC Hydro measure the cost effectiveness of its Revenue Assurance and Field Inspection Teams? Please provide the metrics used.

RESPONSE:

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proportion of grow-ops found to be engaged in theft has consistently been below 5 per cent as compared to over 60 per cent prior to the initiation of BC Hydro's enhanced Revenue Assurance program.

The Revenue Assurance program also includes investigating and resolving overloaded services, customer access and employee safety concerns, and complex metering and billing errors.

2.123.2 When does BC Hydro expect to examine the actual savings achieved from the smart meter benefits so that it can assess the Smart Meter initiative estimates versus actuals? Please explain.

RESPONSE:

BC Hydro does not plan to update the 2016 estimates of theft detection related benefits of the SMI program.

Theft of electricity and large scale unlicensed marijuana production are clandestine activities and, as such, it is not possible to quantify them with the same degree of accuracy as other commercial and residential loads. For this reason, BC Hydro's response to CEC IR 1.52.1 referred to the 2016 assessment of the theft detection related benefits of the SMI program as estimated savings rather than actual savings.

Commercial Energy Consumers Association of British Columbia Information Request No. **2.123.3** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 2
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

123.0 Reference: Exhibit B-6, CEC 1.52.1 and 1.52.4

1.52.1 Please provide quantification for the savings from the theft reduction from marijuana grow ops in $ and GWh.

RESPONSE:

In the Smart Metering and Infrastructure Program Completion and Evaluation Report submitted in 2016, BC Hydro estimated the savings from theft reduction from marijuana grow-ops to be approximately 675 GWh annually by fiscal 2016.

BC Hydro estimated the smart meter benefits for fiscal 2019 from grow-op theft reduction to be $53 million.

While we have not done a formal assessment since fiscal 2016, we still believe this estimate is valid. BC Hydro's proactive Revenue Assurance program has been successful in preventing a recurrence of marijuana grow-op theft and it is possible that the theft savings could be higher than the previous estimate.

1.52.4 How does BC Hydro measure the cost effectiveness of its Revenue Assurance and Field Inspection Teams? Please provide the metrics used.

RESPONSE:

BC Hydro assesses the value of the Revenue Assurance program relative to the deterrent effect of preventing a return to large scale theft. Since fiscal 2016, the

proportion of grow-ops found to be engaged in theft has consistently been below 5 per cent as compared to over 60 per cent prior to the initiation of BC Hydro's enhanced Revenue Assurance program.

The Revenue Assurance program also includes investigating and resolving overloaded services, customer access and employee safety concerns, and complex metering and billing errors.

2.123.3 When and how will the results of the assessment be made available to the Commission?

RESPONSE:

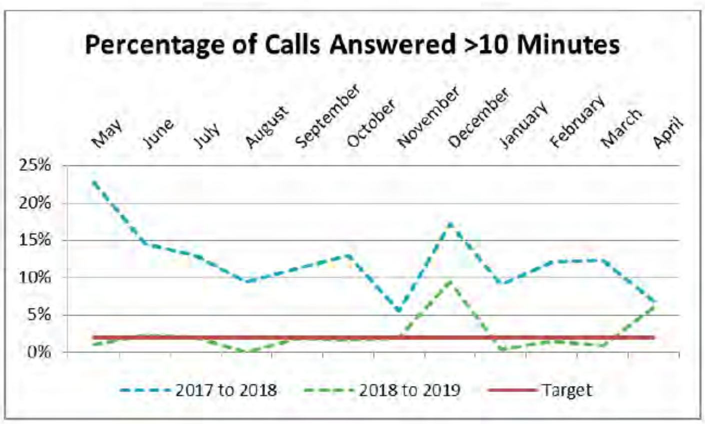
Please refer to BC Hydro's response to CEC IR 2.123.2 where we indicate that a formal assessment of actual versus estimated theft detection benefits is not contemplated at this time.

124.0 Reference: Exhibit B-5, BCUC 1.97.1 and 1.97.2

RESPONSE:

BC Hydro plans its contact centre staffing to answer 75 per cent of calls within 30 seconds ("75/30"); however, we use 75/30 as a target performance level rather than as a minimum threshold.

Our experience is that a monthly service level threshold can result in unintended behaviours that aren't aligned to our objectives of consistent service and managing costs. For example, if wait times were longer at the beginning of the month, Accenture needed to add resources to achieve wait times considerably shorter than 30 seconds so the overall monthly target would be met. Using this example, we don't agree that over-staffing is appropriate if done for the sole purpose of achieving the monthly target (i.e., spending additional money to provide exceptional customer service for the next customer doesn't help the customers that had to wait longer). This is why we've taken the approach of balancing performance using a number of metrics described further in BC Hydro's response to BCUC IR 1.97.2.



2.124.1 Please provide a chart depicting the % wait times (Y axis) by 30 second increments (x axis) up to the longest wait times. Please provide for both 2017-2018 and 2018-2019.

RESPONSE:

Figure 1 below shows the number of calls answered by 30-second increment in fiscal 2018, as well as the cumulative percentage of calls answered at or below the interval. Figure 2 below provides the same information for fiscal 2019.

The figures show wait times with intervals up to 1,800 seconds (30 minutes). In both years, less than 1 per cent of calls had wait times exceeding 30 minutes.

Figure 1 Contact Centre Wait Times, Fiscal 2018

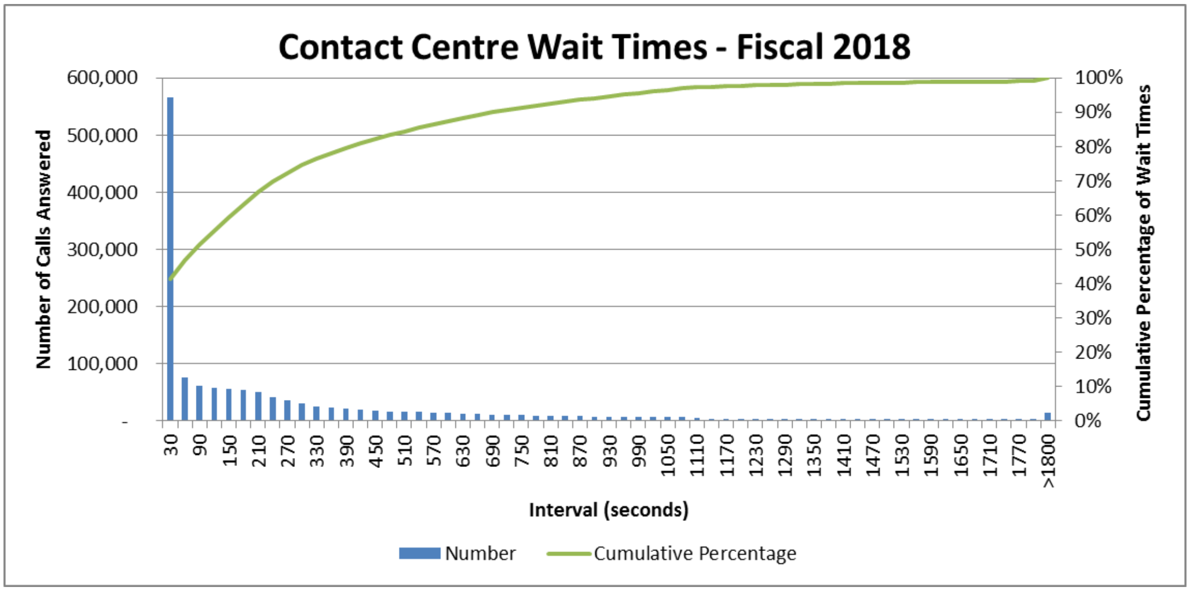
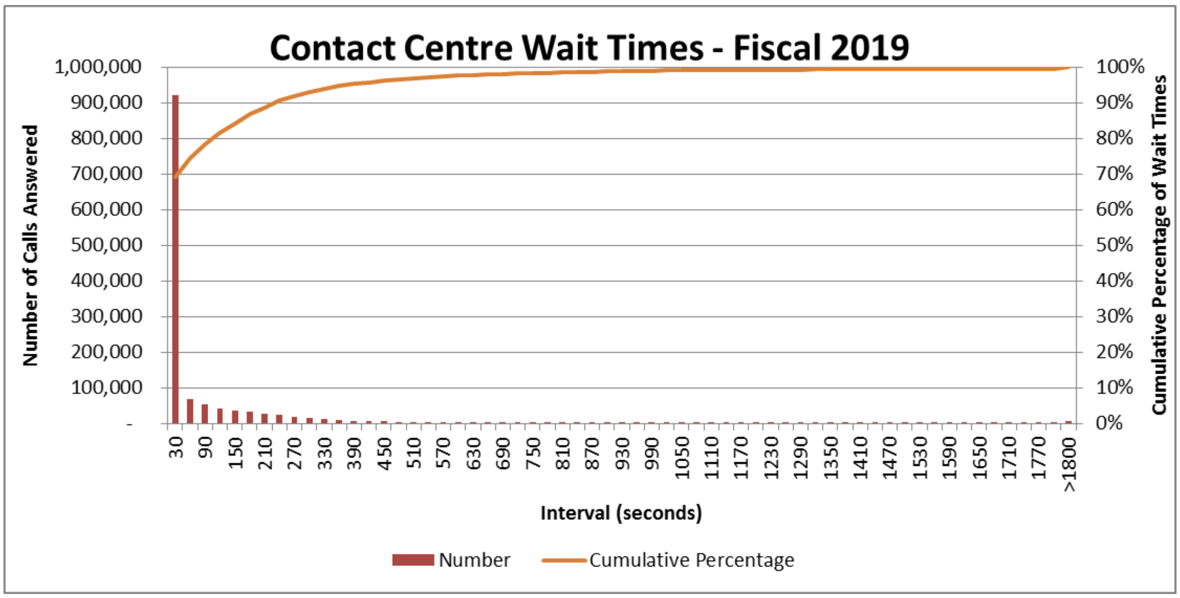


Figure 2 Contact Centre Wait Times, Fiscal 2019



For comparison, Figure 3 below shows the wait time percentages for fiscal 2018 and fiscal 2019 on one chart. Also, Table 1 below summarizes fiscal 2018 and fiscal 2019 contact centre wait times for the key metric intervals identified in BC Hydro's response to BCUC IR 1.97.2, as well as at 10, 20 and 30-minute intervals.

As shown in both Figure 3 and Table 1, wait times in fiscal 2019 were less than in fiscal 2018. In particular, in fiscal 2019, 358,631 more customers had their calls answered within 30 seconds than in fiscal 2018. In addition, 105,729 fewer customers were required to wait for more than 10 minutes in fiscal 2019 than in fiscal 2018.

Figure 3 Comparison of Contact Centre Wait Times, Fiscal 2018 and Fiscal 2019

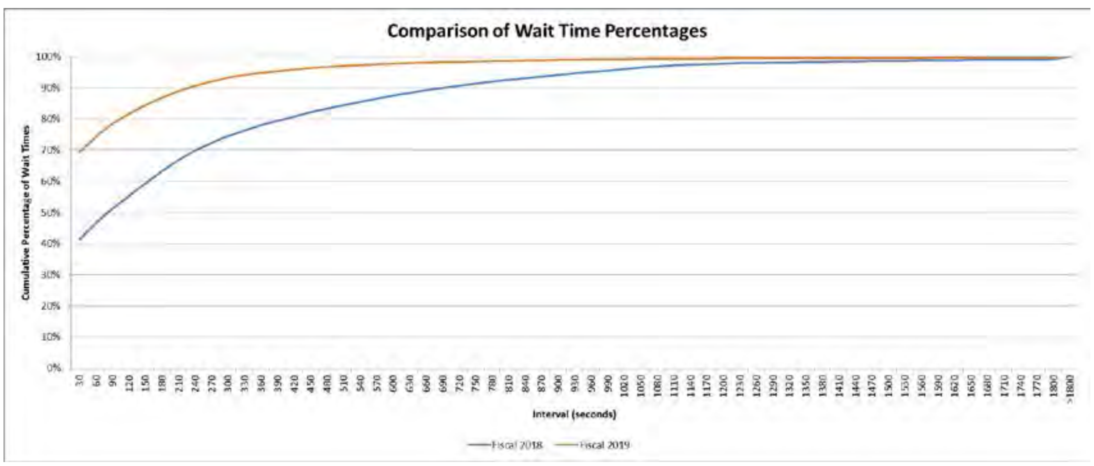


Table 1 Comparison of Contact Centre Wait Times, Fiscal 2018 and Fiscal 2019

Percentage of Calls Answered in:	Post-repatriation Target (%)	Fiscal 2018		Fiscal 2019	
		Number	Percentage (%)	Number	Percentage (%)
30 seconds	75	564,664	41.3	923,295	69.2
300 seconds (5 minutes)	95	1,018,765	74.4	1,242,346	93.1
600 seconds (10 minutes)	98	1,196,531	87.4	1,302,260	97.7
1,200 seconds (20 minutes)	n/a	1,336,745	97.7	1,324,786	99.3

Percentage of Calls Answered in:	Post-repatriation Target (%)	Fiscal 2018		Fiscal 2019	
		Number	Percentage (%)	Number	Percentage (%)
1,800 seconds (30 minutes)	n/a	1,355,182	99.0	1,327,926	99.6
Over 1,800 seconds	n/a	13,556	1.0	5,678	0.4
Total Calls Answered		1,368,738		1,333,604	

125.0 Reference: Exhibit B-6, CEC 1.60.1

1.60.1 In Appendix L, BC Hydro provides its Technology Strategy and 5-Year Plan in a 27 page document prepared in November 2018. Please provide the last five years' versions of the same document to the extent they are available.

RESPONSE:

The following answer also responds to CEC IRs 1.60.2, 1.60.3 and 1.60.4.

BC Hydro has published three technology plan documents over the last five years. The July 2014 and February 2016 documents are attached to this response and the November 2018 document is provided as Appendix L to the Application.

The 2014 Portfolio Plan was designed to communicate the portfolio of information technology projects expected to be delivered over the following five years.

The 2016 Strategic Plan was designed to communicate alignment between the information technology capital delivery portfolio and BC Hydro's strategic priorities.

The 2018 Technology Strategy and 5-Year Plan provides high-level guidance and direction on technology investments across BC Hydro in support of decision making. The intended audience includes BC Hydro's Board of Directors and senior management as well as vendor partners, the BCUC and other interested parties.

The strategy section of the document communicates BC Hydro's approach to selecting and prioritizing technology investments and the types of technology investment required for BC Hydro to achieve its objectives. It was developed in conjunction with interviews of business personnel and understanding BC Hydro's priorities as articulated in its Service Plan. BC Hydro does not make investment decisions based on this document because launching an initiative in support of any element of the strategy requires further technical and financial analysis to provide the appropriate business justification. The strategy should remain relatively constant and will only change with a major change in business direction or technology disruption.

The 5-year plan section of the document shows the technology investments anticipated for the next five years based on BC Hydro's capital plan. BC Hydro expects to update the plan annually. Initiating any project identified in the plan requires a business case and approvals consistent with our financial policies.

The only major initiative with costs greater than $25 million was the Supply Chain Applications project which has been approved by the BCUC. The decision to undertake this initiative is aligned with the Technology Strategy and 5-Year Plan and was justified and approved through a business case, consistent with BC Hydro's financial policies.

2.125.1 The CEC was unable to locate the 2014 and 2016 documents. Please specify where they can be located or provide the documents.

RESPONSE:

BC Hydro inadvertently did not attach the 2014 and 2016 documents and apologizes for this error. Attachments 1 and 2 to this response provide the 2014 and 2016 documents.

BC HYDRO TECHNOLOGY PLAN EXECUTIVE SUMMARY

FISCAL YEAR 2015

FOR GENERATIONS

PRIVATE AND CONFIDENTIAL – See Page 2

JULY 2014

GDS14-196

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A MESSAGE FROM THE TECHNOLOGY VICE-PRESIDENT

Each year the Technology group creates a five year rolling plan describing the portfolio of projects and activities that will be undertaken in support of BC Hydro's business operations and objectives.

The plan this year shows an ambitious portfolio driven by a number of new initiatives in FY2015 including an integrated supply chain, work scheduling and new engineering design tools. The following years are equally full with a new safety management system and integrated work and asset management. The extent of the portfolio, and critical nature of the systems being implemented, clearly shows how Technology has a direct impact on meeting BC Hydro's strategic business objectives: safely keeping the lights on, minding our footprint, succeeding through relationships, fostering economic development, maintaining competitive rates and engaging a safe and empowered team.

With such an extensive workload, the Technology group must work ever more efficiently and effectively to meet the needs of the business while ensuring a future technology foundation capable of supporting future growth and advances in technology. Over the last year, the group has successfully re-organized to strengthen business unit relationships, critical to effective and quality service delivery. The group has also developed project and work program delivery methods to streamline processes and use resources more efficiently. The move from the Edmonds Data Centre to the new Kamloops Internet Data Centre was a major achievement and provides a state of the art facility that will improve our systems availability and reduce support costs. In all of this, the people, along with the skills and commitment they bring to the job, are fundamental to delivering on the plan. My team is committed to developing our people and providing opportunities for growth.

Within the plan there two major components of technology: technology that enables business operational excellence and a technology foundation for security, telecommunications, systems and information that supports reliability and operational performance.

Business driven solutions strive to leverage our enterprise systems and, through intelligent architecture and design, are tailored to provide the required business functionality in an optimal way. Capturing information once and making it available for many uses, is a fundamental component of the approach. The five-year plan also reflects a strategy of incremental implementation based on meeting business priorities while maximizing the opportunity for success. Knowing how much change the organization can absorb while increasing technological enablement is a key component to the plan.

The foundational technologies: applications, infrastructure, data, telecommunications and security systems, provide the enterprise with a platform on which to build and take advantage of fully integrated processes and systems. These end-to-end systems can reduce duplication of data and eliminate low-value activities. The technology foundation requires highly secure systems and processes with 24x7 availability, optimum performance standards and full redundancy where necessary. The Technology Plan reflects the implementation of a foundation that is "future proofed"; asset value is protected from rapid technology change through a risk based approach to investment. Fundamentally, the foundation has to support the evolving needs of the business while operating within the risk tolerance of the organization.

The world of technology changes at a rapid pace, and as a business, we need to keep up with these changes. The most dominant near-term technology trend affecting the utility sector is the integration of advanced information technologies (IT) and real time operational technologies (OT) to create new systems that replace or augment manual transactions and provide information for automated decision making. Technology advances in mobile applications and devices provide an opportunity for BC Hydro both for the workforce and in communicating with our customers. Trends in sensor technologies and the internet-of-things lead to future opportunities in asset management, condition based maintenance and operations. Advances in computing technology such as cloud based systems and high-performance environments can be judicially used to provide the performance expected from today's users. We continue to pursue activities in these areas to ensure BC Hydro is fully prepared to take advantage of opportunities in the future.

In closing, though this document is produced annually, it reflects a dynamic, working plan. Together, as requirements evolve, we will continue to prioritize and refine our estimates to deliver the highest value to BC Hydro.

Don

Don Stuckert
Vice-President, Technology

INTRODUCTION

BC Hydro's Technology Group is responsible for the planning, design, delivery, operations, support and management of BC Hydro's information and communications technologies. The Group supports and enables the business through: sustaining and enhancing existing systems and assets, building new capability, and preparing for the future technology needs of the organization.

The BC Hydro Technology Plan is a five year view of technology solutions funded or resourced by the Technology Group and is updated annually. The Plan is comprised of three sections each of which can be read independently: an Executive Summary, Portfolio Plan and Operations Plan.

THE EXECUTIVE SUMMARY

The **Executive Summary** (this document) is designed for the Board, Executive Team and Technology Governance Committee and includes the Plan's strategic context as well as summaries of the Portfolio Plan and Technology Operations sections. The objective of the Executive Summary is to communicate:

- The business operations and strategic context in which the Technology Plan is developed;
- A summary of the Five-Year Technology Portfolio Plan including portfolio risk assessment; and,
- The governance, structure and processes in place to deliver on the Technology Group mandate and performance improvement plan for fiscal 2015.

SECTION 1: THE TECHNOLOGY PORTFOLIO PLAN

The **Technology Portfolio Plan** is designed specifically for Business Unit Managers and the Technology Governance Committee to communicate the plan for Technology investment over the next five years. The Portfolio is assessed for implementation risk and recommends mitigating actions. The objective of the Plan is to communicate:

- The portfolio of projects and activities identified for fiscal years 2015-2019;
- The estimated schedule, financial and human resources required to deliver the portfolio based on forecast demand;
- The direct links between technology projects and business unit initiatives; and,
- The portfolio risk assessment and recommended mitigation.

SECTION 2: THE TECHNOLOGY OPERATIONS

The **Technology Operations** document is designed for the Technology Governance Committee and Technology Group Management and describes the governance, structure and processes of the Technology Group established to fulfill the requirements of the Technology Plan. The objective of the Technology Operations document is to communicate:

- The Technology Group mandate;
- The Governance and Organizational structure;
- Key Technology Processes;
- Key Technology Operations Initiatives;
- Performance Measures and Scorecard for fiscal year 2014-2015; and,
- Action Plan for fiscal year 2015.

This document comprises the **Executive Summary** section of the BC Hydro Five-Year Technology Plan, Fiscal Years 2015–2019.

TECHNOLOGY MANDATE

Technology is responsible for optimizing information technology and telecommunications, managing and delivering networks and systems, and delivering technology services. We ensure information technology and telecommunications align with BC Hydro's overall business goals. We enable BC Hydro employees and customers to do what they need to do, and deliver measurable business benefits and efficiencies.

The Technology Plan is developed by the Technology Group and BC Hydro's business units, in the context of the group's mandate, BC Hydro's strategic objectives, and the greater environment in which the organization operates.

RESPONSIBILITIES

The Technology Group is responsible for planning, design, delivery, operations, support and management of BC Hydro's information and communications technologies. The Group provides technology services to BC Hydro as an enterprise as well for the individual business units. This means meeting current business objectives and future proofing for BC Hydro's evolving business. This responsibility includes the strategy, planning, delivery and sustainment of these services, including the operation and maintenance of all related assets.

The Technology Group provides the following functions for the corporation:

- Manage/implement technologies to meet business requirements and objectives;
- Manage BC Hydro's information technology, telecommunication and networked assets;
- Provide technology support and help desk services;
- Provide technology governance through architecture standards and policy;
- Provide information and records management services;
- Provide subject matter expertise and support for technology contracts;
- Ensure compliance with technology regulations and policy; and,
- Develop capability in high-value future technologies.

Through these functions the Technology Group is engaged in every stage of the technology lifecycle from identification of the initial technology solution, proof-of-concept, demonstration (if required), pilot, design, build, operation, sustainment and eventual decommissioning.

Figure 1 on the next page, illustrates the interconnected asset, project and innovation lifecycles. These lifecycles operate within the context of technology management and are guided by strategy, planning and controlling activities.

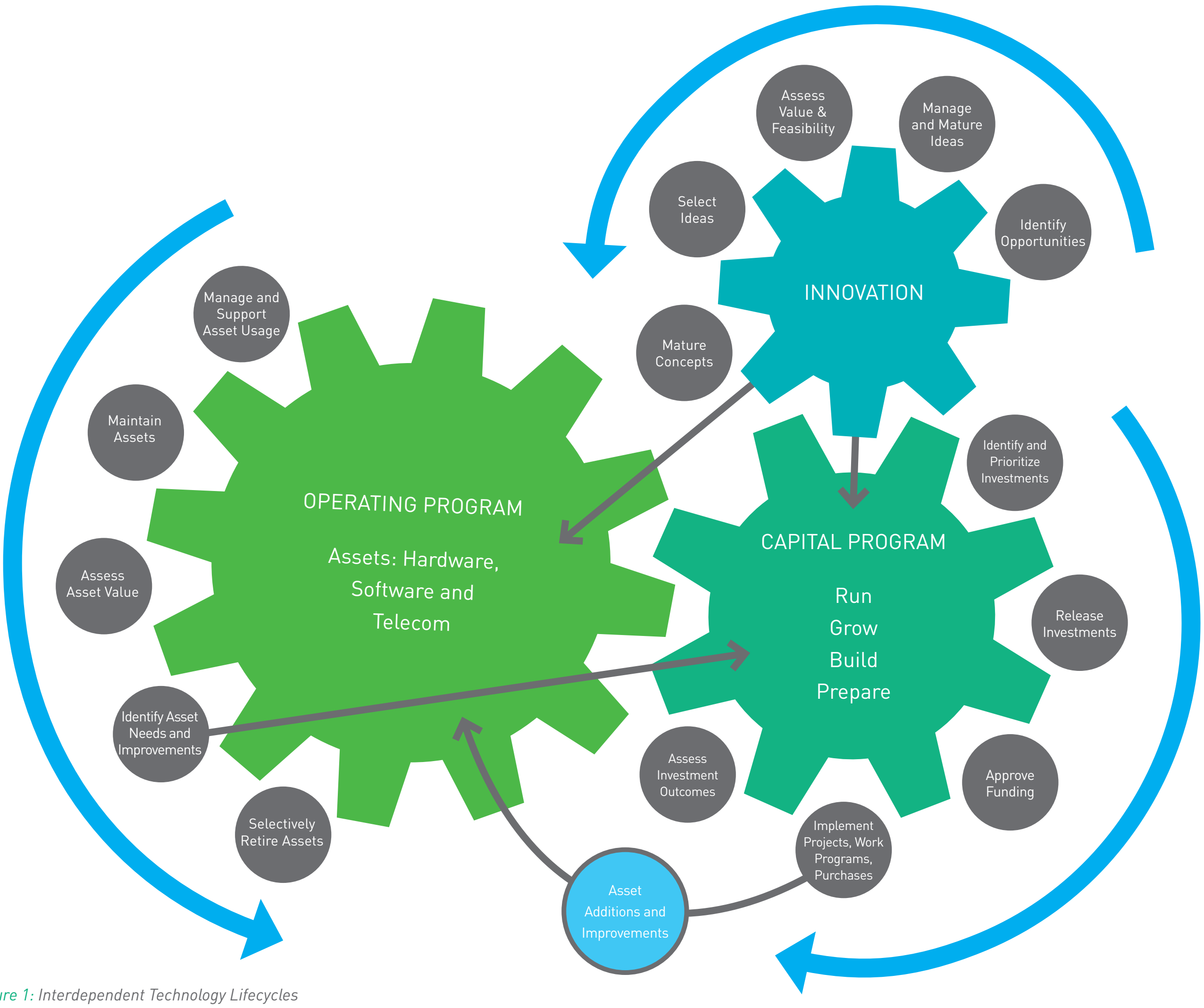


Figure 1: Interdependent Technology Lifecycles

The Technology Plan stays the course set in previous years of building a solid technology foundation following the guiding principles of integrated systems, simplifying the environment, prioritising investment, creating a single source of truth for information and simplifying reporting. In addition, since technologies across the organization are growing ever more integrated, a shared accountability model is required to plan and execute technology investments holistically.

This enterprise approach to technology is consistent with the concept of One BC Hydro. Such an approach enables and improves business capabilities through cross-functional business processes, integrated systems development, a single source of truth for information, a simplified technology environment, shared applications and reporting, and cost saving measures.

The key practices required to make this model work are:

- Integrate people, process, and technology to achieve the benefits of increased productivity, efficiency and an end-to-end customer based view.
- Simplify business processes and the technology environment with fewer, more strategic and better-utilized technologies.
- Focus investments in the most critical business process areas that will help BC Hydro achieve its strategic objectives.
- Create a single source of truth for data and provide relevant, accurate and timely information for better decision making.

ORGANIZATIONAL STRUCTURE

The Technology Group is organized along functional lines for business unit services, portfolio and project delivery, enterprise application services, telecommunications, infrastructure and cyber security, enterprise architecture and foundational planning, and applied technology innovation. The revenue assurance lead currently reports to the Vice-President of Technology in the role of supplying data analytics services to the business. Revenue assurance activities are included in the Smart Metering Infrastructure plan and are not included in the Technology plan.

Technology governance is provided by the Technology Governance Committee which includes members of the Executive Team and is chaired by the Executive Vice-President for Generation. The Committee reports to the Audit and Finance Committee of BC Hydro's Board of Directors.

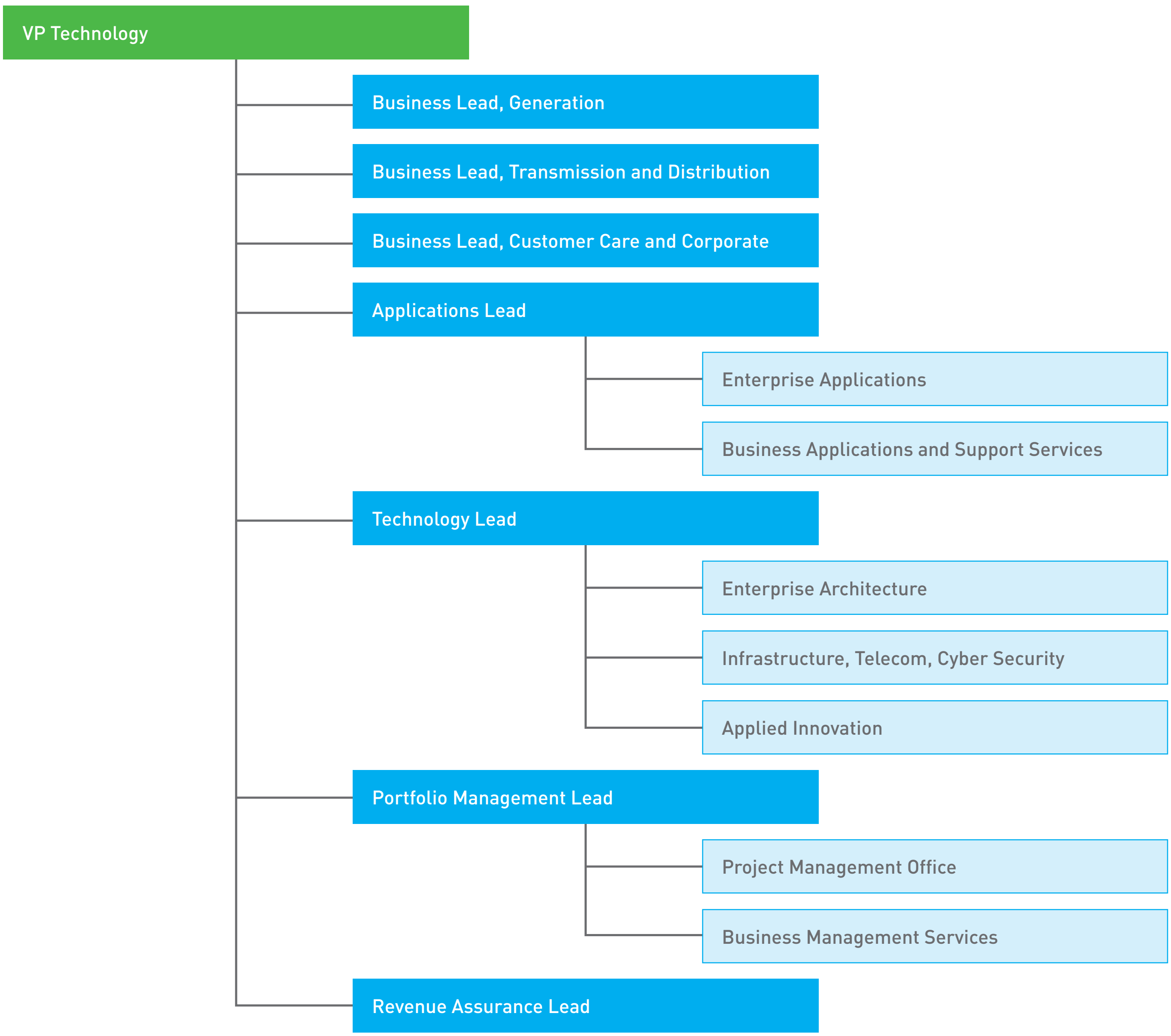


Figure 2: Technology Organization Structure

A strong technology governance structure creates shared accountability and a foundation for success. An important part of this governance structure is the following set of technology principles that continues to guide technology decisions.

1. **Business strategy drives capabilities development**
   The business operations strategy and objectives drive the development of business capabilities and processes.

2. **Business process is defined both in terms of enterprise and business groups**
   Business capabilities and processes may support one or more business groups, or the enterprise as a whole.

3. **Business process design must be "end to end"**
   Each business process will be looked at from its triggering event to value delivery. For example, a customer self-service process begins with a technology-enabled customer interaction and ends with value delivered to that customer via a completed transaction or information exchange.

4. **Business capabilities development drives the Technology Plan**
   Technology operations and the technology portfolio are designed to support and enable BC Hydro's changing business capabilities and processes, addressing both current and anticipated needs.

5. **Prioritize Requirements (80/20 rule)**
   Business requirements that serve critical business functions and drive the highest risk reduction and value will be delivered first, while other requirements may be deferred.

6. **Design for "Tool Time"**
   Most business processes have a "transactional" nature. By automating much of the transactional processing, communication, and information management, BC Hydro workers will have more time to perform their jobs.

7. **Single source of information**
   Incorporate the concept of authoritative information. Data is typically copied, shared, combined, transformed and used to meet various business process needs. A known data source must be established as authoritative.

8. **Test and validate current technology assets**
   When considering alternative technology solutions to address a business need, look first to existing technology assets and services. Always favour proven technologies and use an applied R&D environment to test unproven technologies.

9. **Balanced short and long term strategic investments**
   Maintain a balanced portfolio of technology investments in order to sustain existing business capabilities, expand or extend existing capabilities, and build new capabilities.

10. **Consistent and effective governance**
    The technology governance structure provides a foundation for success by setting priorities, overseeing the allocation of resources, addressing portfolio risks and interdependencies, and providing operational oversight.

THE PORTFOLIO PLAN – CAPITAL PROGRAM

A primary role for the Technology Group is to support and enable the business units in meeting strategic objective targets through business specific technology solutions and broad enterprise foundations. The objective of the Technology Portfolio Plan is to communicate the programs and services to be delivered over the next five years that will enable the business to accomplish its goals and objectives.

Many of the projects and activities identified in the plan are in support of the following key business initiatives:

- Re-engineering the supply chain process to incorporate consolidation, categorization, improved processes and analytics;
- Developing a safety management system incorporating policy, practice, process and system solutions;
- Leveraging meter, grid and operating data for multiple purposes across the organization;

- Enhancing the Geographical Information System (GIS) infrastructure to improve asset management;
- Developing asset management solutions for both fixed and linear assets;
- Implementing work management and scheduling solutions for T&D and Generation;
- Implementing mobile business process and solutions for front line workers;
- Developing design tools for distribution engineering and extending use to other parts of the organization; and,
- Increasing use of the electronic and physical records management solutions.

Many of these initiatives rely on the incremental build out of SAP as a high-volume, transactional system used across BC Hydro's core and supporting business areas. SAP will provide a common, integrated, highly reliable system of record.

PORTFOLIO CATEGORIZATION

In the Technology Portfolio, projects and activities are categorized by type in order to distinguish between discretionary and non-discretionary work and to assess the cumulative level of technology, delivery and adoption risk. In general, "Grow" and "Build" projects are discretionary, business-benefit-driven, and contain a higher degree of risk. They often introduce new systems to the business and lead to an increase in technology operating costs. The number of projects in these areas is a good indication of the overall portfolio risk. These projects are initiated and driven through a specific business unit but in many instances are designed with the overall enterprise in mind so as to be implemented across the company. The "high risk" identified in the Transformation Project (Work Management, Asset Management and Supply Chain) and the recent decision to defer, is an illustration of managing "Build" project risk.

Projects and activities categorized as "Run" are generally sustaining and non-discretionary. They are critical to the operations of technology to support availability, performance and reliability.

The "Prepare" category is used to denote capability development activities in advanced technologies that have future potential value to the business. These projects are discretionary and technology risk is high. They are usually managed as a proof-of-concept or pilot.

TRANSMISSION & DISTRIBUTION

The Transmission and Distribution (T&D) Portfolio Plan is dominated by six major "Build" projects either underway or starting in fiscal 2015. All have medium, high or very high risks associated with the technology, delivery and adoption. Specifically the "Distribution Management System", "Distribution Work Scheduling", and "Schedule, Dispatch, & Mobility" projects are high risk from a process and operations change perspective.

In addition, over fifteen "Grow" projects are identified for fiscal year 2015 that are considered medium to high risk. Included in this category, is the "Express Connect" initiative, in which T&D is defining improvements to cross-functional customer-facing processes and systems, in cooperation with the Customer Care & Power Smart, and Corporate Communications groups. The Technology Group will review the timing and potential interdependencies between these projects in order to minimize disruption to the business, ensure the availability of resources and manage costs.

T&D has identified required upgrades to Project/Portfolio Management (PPM), SAP and PassPort enterprise applications.

Note: Forecast capital and initiative OMA at the portfolio and project levels reflect best estimates at May 30th. Figures may differ from the 10 Year Capital Plan however Technology will manage to the approved targets. Unspecified forecast is included in the CAP and IOMA numbers.

KEY: bar thickness indicates forecast expenditure

<$1M | $1M–$5M | $5M–$25M | $25M–$100M

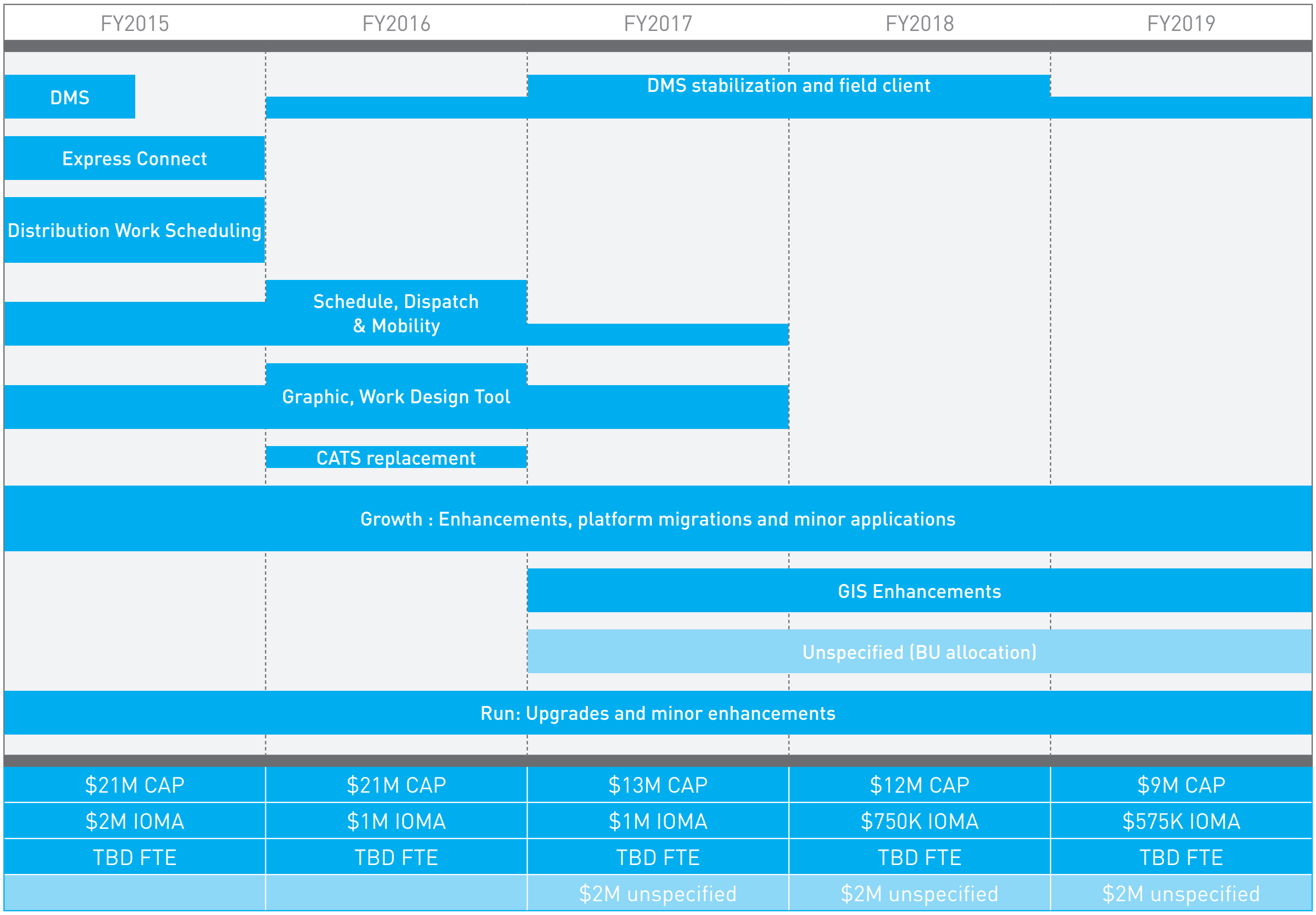


Figure 3: Technology Portfolio Plan for T&D Fiscal 2015–2019

Full details of the T&D portfolio are documented in Section 1: The Portfolio Plan.

NOW	IN FIVE YEARS
• Refresh application technology platforms to ensure software versions are supported. • Enhance common applications to extend use across T&D. • Enhance systems to support improved work management practices (planning, scheduling, and dispatch). • Develop plan and initiate projects to improve support and tools for field crews. • Modernize customer-facing processes such as customer connections.	• A single, integrated work management system for planning, scheduling and dispatch. • Simplified IT tools and software for our field crews that support data capture at source. • An upgraded Energy Management System platform that ensures continued reliability and effective management of our grid. • An updated Geographic Information System platform that supports T&D's future business requirements. • Project in progress to improve T&D operations through data analytics.

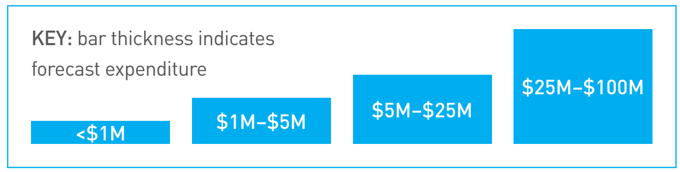
GENERATION

The Generation portfolio plan includes two "Build" projects: "Engineering Parametric Modeling" and"Construction Contract Management". The "Engineering Parametric Modeling" project is considered high risk based on the unfamiliar 3-D modeling technology and requirement for high performance computing environment.

There are twenty-two "Grow" projects identified for fiscal year 2015 described as medium to low risk. The Technology Group will review the timing and potential interdependencies between these projects in order to minimize disruption to the business, ensure the availability of resources and manage costs.

Generation has identified required upgrades to PPM (Primavera), SAP, and FileNET enterprise applications.

Note: Forecast capital and initiative OMA at the portfolio and project levels reflect best estimates at May 30th. Figures may differ from the 10 Year Capital Plan, however Technology will manage to the approved targets. Unspecified forecast is included in the CAP and IOMA numbers.



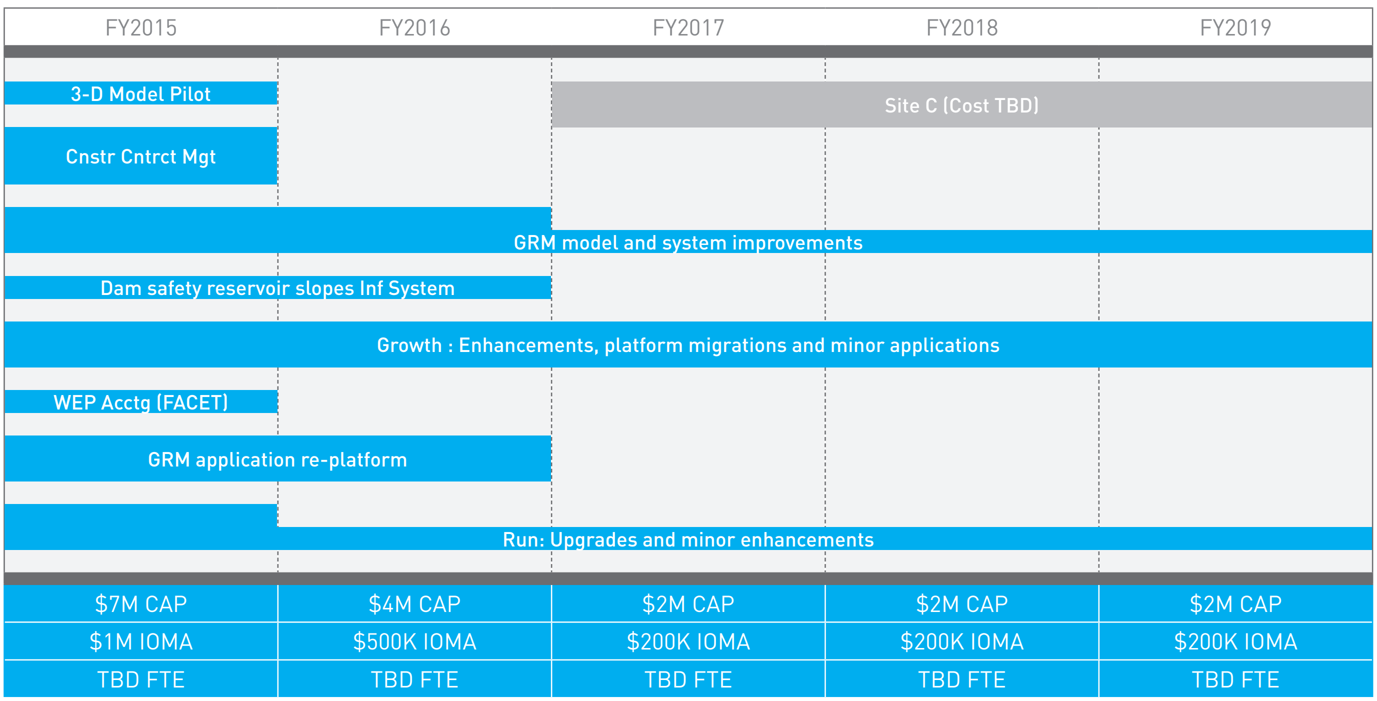


Figure 4: Technology Portfolio Plan for Generation and Site C Fiscal 2015–2019

Full details of the Generation portfolio are documented in Section 1: The Portfolio Plan.

NOW	IN FIVE YEARS
• Migrate Generation Resource Management applications to a supported platform. • Initiate implementation of a high performance computing environment to support 3-D drafting and modelling capabilities for design and construction. • Improve Construction and Contract Management capabilities. • Enhance Energy Planning Information Central (EPIC), to support the energy planning function. • Develop roadmap for Dam Safety and initiate application-refresh projects.	• Integrated asset investment planning tools with portfolio optimization capabilities. • Fully deployed high-performance computing environments capable of supporting advanced business needs such as 3-D parametric modelling and advanced data modelling and analysis. • Multiple design disciplines, including construction staff are working off the same 3-D parametric models. • There is a single source for energy planning data supported and maintained through a defined governance structure. • Dam Safety projects in progress, including an intuitive navigational tool to access related documents, records, and pictures.

SITE C

The Site C Portfolio plan includes projects comprising the implementation of infrastructure and systems to support the next phase of the Site C project. Site C will leverage the engineering modeling systems implemented for Generation.

Site C has identified upgrades to PPM (Primavera), SAP and PassPort enterprise applications in order to support the need for controlled access to financial reporting and project management.

Full details of the Generation portfolio are documented in Section 1: The Portfolio Plan.

NOW	IN FIVE YEARS
• Plan and implement Site C infrastructure and systems to support design and procurement functions.	• Fully implemented and supported systems infrastructure as required for Site C procurement, contract management, design, and construction.

CUSTOMER CARE & POWER SMART

The Customer Care and Power Smart Portfolio plan, in partnership with Corporate Communications and T&D, has three "Build" projects underway: "Express Connect", "Customer mobility" and "Customer Self-Serve and Interactive Voice Response". All are medium to high risk due to the customer-facing nature of the systems and the technology integration required.

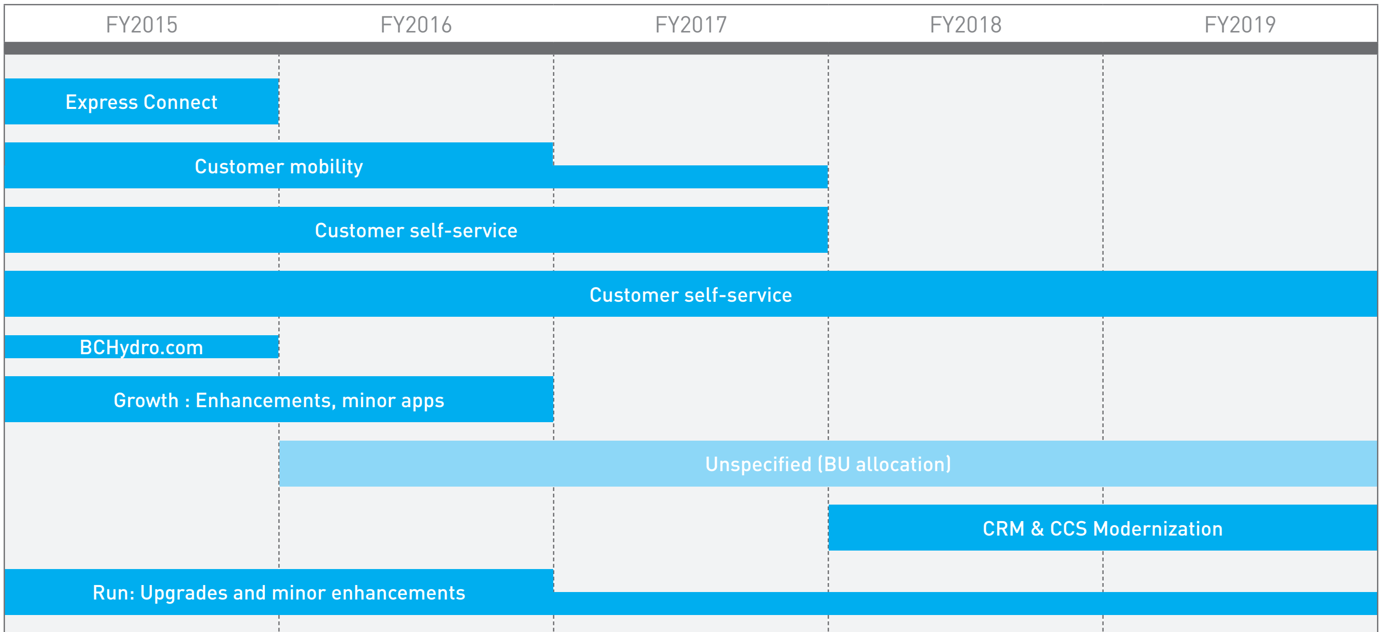
Additional "Grow" projects are planned in the areas of Customer Portal, BCHydro.com, and Customer Care solutions. These are rated as medium risk due to the business resources needed and in some cases the complex platforms and new technologies involved. Also, careful staging and scheduling is needed due to the process and systems integration involved.

Customer Care & Power Smart will leverage planned upgrades to the enterprise application SAP.

Note: Forecast capital and initiative OMA at the portfolio and project levels reflect best estimates at May 30th. Figures may differ from the 10 Year Capital Plan, however Technology will manage to the approved targets. Unspecified forecast is included in the CAP and IOMA numbers.

KEY: bar thickness indicates forecast expenditure

<$1M | $1M–$5M | $5M–$25M | $25M–$100M



FY2015	FY2016	FY2017	FY2018	FY2019
$13M CAP	$6M CAP	$4M CAP	$4M CAP	$5M CAP
$1M IOMA	$100K IOMA	$200K IOMA	$900K IOMA	$600K IOMA
TBD FTE	TBD FTE	TBD FTE	TBD FTE	TBD FTE
	$1M unspecified	$2M unspecified	$2M unspecified	$2M unspecified

Figure 5: Technology Portfolio Plan for Customer Care and Power Smart Fiscal 2015–2019

Full details of the Customer Care & Power Smart portfolio are documented in Section 1: The Portfolio Plan.

NOW	IN FIVE YEARS
• Deliver self-service improvements to bchydro.com and IVR. • Enhance Customer mobile experience. • Establish plan to improve customer-centric view, potentially utilizing Customer Relationship Management (CRM) capabilities. • Develop integrated technology plan to meet customer preferences including offers and solutions such as Power Smart and other customer programs.	• Fully functional and integrated self-service capability through bchydro.com on both web and mobile devices. • Customer Care & Power Smart systems aligned for seamless customer experience. • Customer Centric View deployed for industrial, commercial and residential customers, including functions in support of Corporate Communications, T&D and other parts of the business. • Analytics solution in place to drive value from SMI data in conjunction with other sources of data, to deliver insights to the customer and to internal business decision-making.

CORPORATE GROUPS

The Corporate Group Portfolio plan is dominated by investment in the Supply Chain "Build" program. This program is comprised of complex, high risk projects that require integration of multiple systems and business process changes impacting large user groups across the company. These projects are guided by the supply chain systems roadmap that builds toward integrated systems in support of operational efficiency. In the immediate term, investment is focused in four Supply Chain projects whose goal is to improve processes and supporting technologies, prior to the replacement of PassPort.

Introduction of Fleet Telematics is new to BC Hydro and requires a demonstration proof-of-concept before it can be defined as a project.

Three major "Grow" projects are planned: "Communications Digital Repository", "Fleet Garage Management", "SH&E Management System". Development of the Safety, Health and Environment (SH&E) Management system requires systems integration support and has dependencies on other programs (e.g., Work Management, Asset Management). The other projects have lower technology risks but require careful staging and scheduling to ensure effective roll-out to the business.

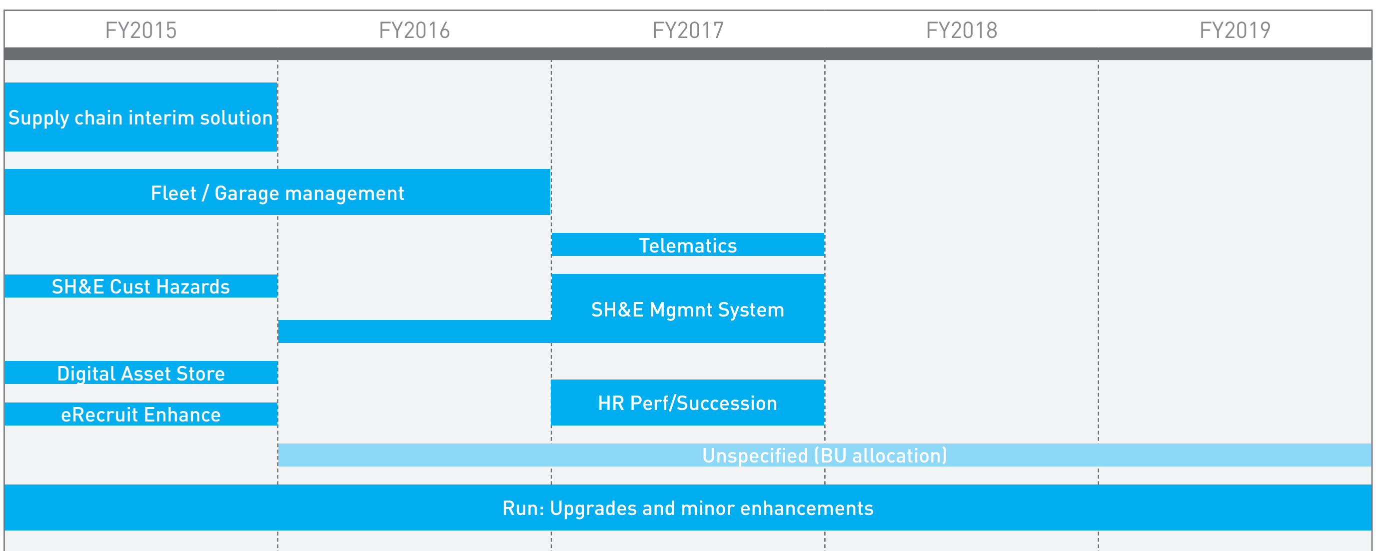
Human Resources and Training continues to leverage the SAP Human Capital Management (HCM) footprint, with a focus on integrating remaining legacy and stand-alone systems. Improved usability and mobile access to all core HR & training functionality are also key priorities. Full integration among applications, including other SAP modules, is essential to achieving required operational efficiencies.

Corporate Finance requires continued enhancements and upgrades to SAP, including a focus on Governance and Risk Controls (GRC), to improve security, privacy and internal controls across applications. Information management, including archiving strategies for key corporate systems, requires review and active planning to ensure continued usability of the core financial systems.

Note: Forecast capital and initiative OMA at the portfolio and project levels reflect best estimates at May 30th. Figures may differ from the 10 Year Capital Plan, however Technology will manage to the approved targets. Unspecified forecast is included in the CAP and IOMA numbers.

KEY: bar thickness indicates forecast expenditure

<$1M | $1M–$5M | $5M–$25M | $25M–$100M



FY2015	FY2016	FY2017	FY2018	FY2019
$12M CAP	$5M CAP	$9M CAP	$2M CAP	$2M CAP
$2M IOMA	$700K IOMA	$1M IOMA	$60K IOMA	$60K IOMA
TBD FTE	TBD FTE	TBD FTE	TBD FTE	TBD FTE
	$1M unspecified	$1M unspecified	$1M unspecified	$1M unspecified

Figure 6: Technology Portfolio Plan for Corporate Fiscal 2015–2019

Full details of the Corporate Groups portfolio are documented in Section 1: The Portfolio Plan.

NOW	IN FIVE YEARS
• Complete supply chain systems enhancements to meet immediate business needs. • Define SH&E management system functionality in selected risk areas. • Implement Fleet management system. • Implement SAP enhancements for Finance. • Implement Digital Asset repository. • Implement SAP enhancements for HR & Training. • Finalise plan for expanded HR & Training SAP modules.	• Full supply chain implementation in SAP. • Fully integrated systems for SH&E Management System. • Integrated solution for Fleet, including Telematics enabled processes where appropriate. • Integrated and expanded HR SAP HCM system including succession, compensation and performance management. • A consistent SAP Portal experience that enables access to SAP HR, Finance and Supply Chain services regardless of device or platform.

MANAGING THE TECHNOLOGY FOUNDATION

Over the past five years, the Technology Group has taken an incremental approach to building out BC Hydro's technology foundational systems. The Technology Group is responsible for ensuring that BC Hydro's information and communication technologies and systems are robust and resilient to a level that satisfies our tolerance for enterprise risk. These foundational technologies underpin the business systems and are critical to business operations reliability. The focus for the technology foundation is on reliability, performance, availability, efficiency and security.

Projects and activities related to managing risk include replacing obsolete infrastructure, renewing applications platforms, regulation compliance, and incorporating redundancy into critical assets. The Technology Foundation includes: applications, data and information, infrastructure (devices, servers and storage), security (all electronic security including NERC CIP), and telecommunications (all types of telecom and control systems).

Note: Forecast capital and initiative OMA at the portfolio and project levels reflect best estimates at May 30th. Figures may differ from the 10 Year Capital Plan, however Technology will manage to the approved targets. Unspecified forecast is included in the CAP and IOMA numbers.

KEY: bar thickness indicates forecast expenditure

<$1M | $1M–$5M | $5M–$25M | $25M–$100M

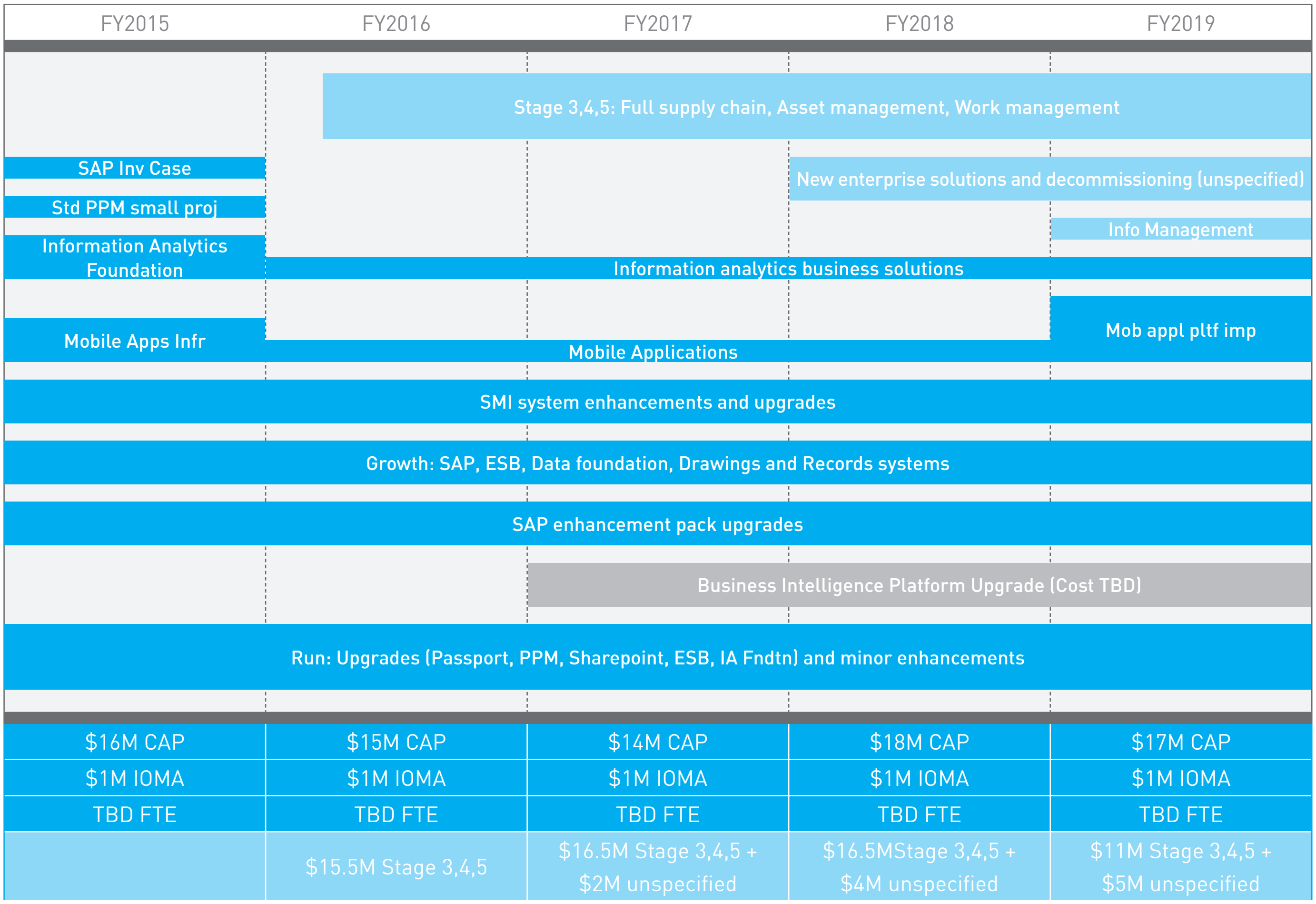


Figure 7: Technology Portfolio Plan for Foundation Applications Fiscal 2015–2019

The Foundation Applications portfolio is overshadowed by the Full Supply Chain, Asset Management and Work Management business initiatives that require new modules and enhancements to SAP, consolidation of SAP and PassPort, and the eventual retirement of PassPort. These initiatives are described as "Stages 3-5 for Supply Chain, Asset Management and Work Management" and are shown on the Foundational Applications plan as they support business processes in T&D, Generation and Corporate Groups business units. These projects are high risk due to the number and nature of the business operations that could potentially be disrupted. They require strong coordination to manage dependencies, leverage common functions and processes across business units, and coordinate system design.

Supply chain projects starting in fiscal 2016 have significant integration requirements and will eventually move the Supply Chain functionality from PassPort to SAP. An interim solution for Supply Chain is shown on the "Corporate Groups" plan and includes functional changes to PassPort, SAP, Sharepoint and Meter Processing to support new business processes. A version upgrade for PassPort is also required (shown on the Foundational Applications plan).

Original estimates for "Stages 3-5 for Supply Chain, Asset Management and Work Management" called for a total of $185M however only $60M is identified in the capital plan. A decision on moving forward with the projects is scheduled for third quarter, fiscal 2015. The decision will be based on the availability of business and technology resources and an implementation plan that reduces delivery risk.

There are multiple "Grow" Applications projects identified. These are all assessed as low risk, however, the volume of projects suggests a need for careful coordination and management to minimize disruption and impact of dependencies.

NOW	IN FIVE YEARS
• Developing energy theft analytics solution; implementing departmental reporting solutions. • Upgrading PassPort; implementing interim transaction support solutions. • Developing point solutions for Generation GIS. • Piloting data virtualization technology.	• Data quality tools implemented for batch based integration; Geospatial data warehouse foundation established. • Consolidated enterprise transactional system (SAP), PassPort retired. • Generation GIS foundation established for slopes management. • Data virtualization implemented to support streamlined access to data.

Note: Forecast capital and initiative OMA at the portfolio and project levels reflect best estimates at May 30th. Figures may differ from the 10 Year Capital Plan, however Technology will manage to the approved targets. Unspecified forecast is included in the CAP and IOMA numbers.

KEY: bar thickness indicates forecast expenditure

<$1M | $1M–$5M | $5M–$25M | $25M–$100M

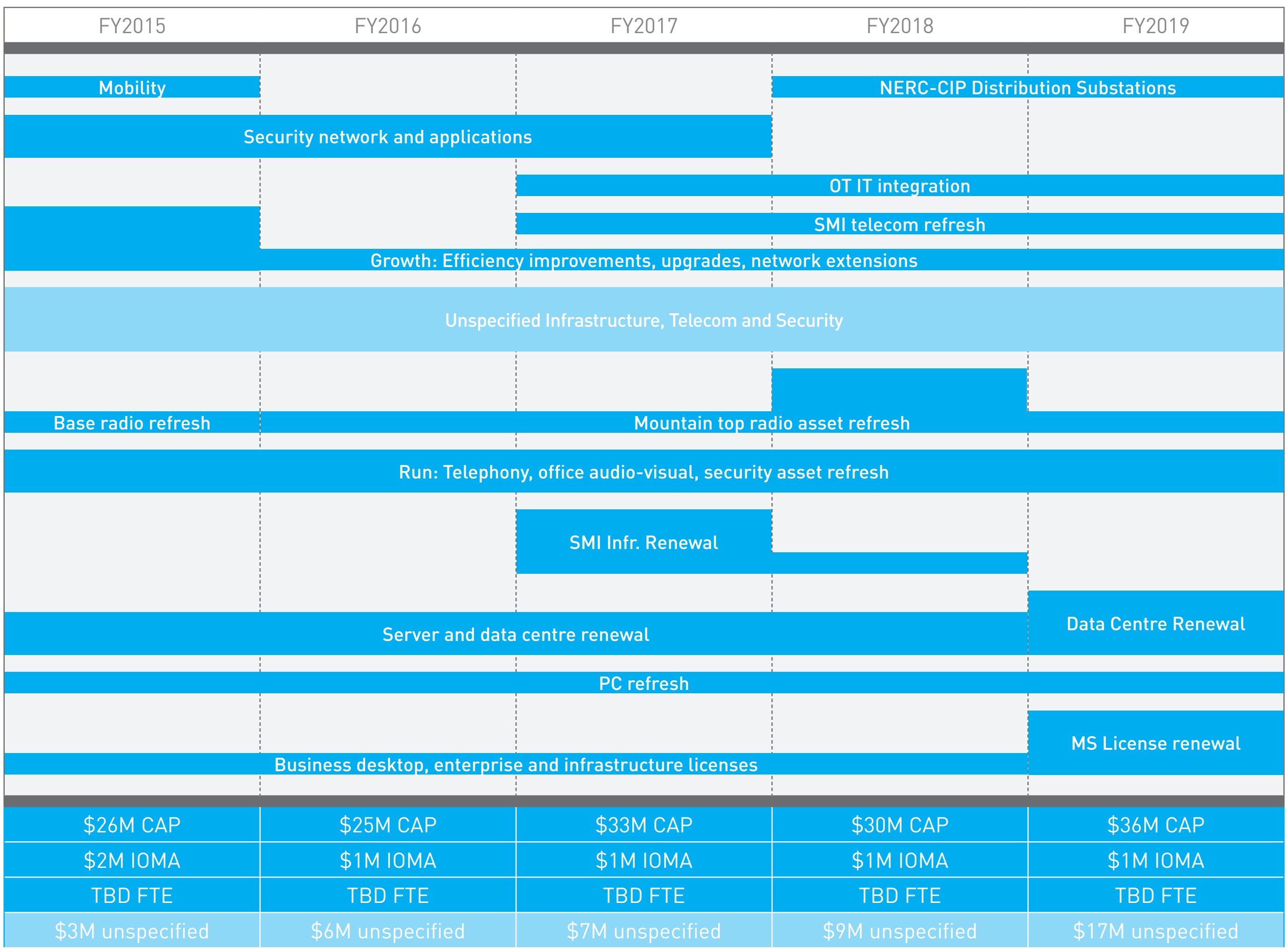


Figure 8: Technology Portfolio Plan for Foundation Infrastructure, Telecom and Cyber Security Fiscal 2015–2019

Infrastructure "Build" and ""Grow" projects are mostly telecom and are considered medium to high risk due to resource constraints and complexity of coordination with providers. There are two "Prepare" projects: "Mobility Applications" and "Data Analytics", described later in this section.

There are a significant number of major "Run" activities: Enterprise Application support, Telecommunications and Infrastructure support and maintenance, Data and cyber security systems support and maintenance. All of these Applications and Systems infrastructure require substantial on-going maintenance, modifications and enhancements.

Full details of the Technology Group portfolio are documented in Section 1: The Portfolio Plan.

NOW	IN FIVE YEARS
• Implementing Identity Management; Implementing centralized logging solutions; Expanding desktop security controls.	• Layered security - strengthened security perimeter, strengthened desktop controls; key systems logging centrally.
• Planning modernization of data backup and recovery infrastructure; preparing for annual disaster recovery test.	• Backup and recovery solution implemented; Disaster recovery site re-aligned to production data center.
• Deploying Digital Radio; expanding Wi-Fi services.	• Wi-Fi 33 standard across all office locations; Digital radio deployed across Lower Mainland.
• Deploying backhaul networks to support SMI needs.	• MPLS across all key network transports; Fiber as standard to all new facilities (owned or leased).

PREPARING THE FUTURE FOUNDATION

Business technology investments are influenced by technology advances, and the requirements of our stakeholder, regulator, customers and business units.

For more than 20 years, the most dynamic technology sector has been the Information Technology and Telecommunication (ITT) sector. The most dominant near-term technology trend affecting the utility sector is the integration of advanced ITT and real time Operational Technologies (OT) to create new machines or systems that either replace or augment human decision-making.

Internally, BC Hydro faces challenges with an aging workforce, aging infrastructure, demands from new loads, evolving customer needs, and a mandate to keep the rates low for our customers. Technology investment can provide opportunities to retain institutional knowledge, improve safety and reliability, manage load and create operational efficiencies.

The Technology Group supports and enables the business through: sustaining and enhancing existing systems and assets, building new capability, and preparing for the future technology needs of the organization. In preparing for the future, the Technology Group is engaged in a number of activities to develop capability based on the technology drivers described above. The type of activity is based on an assessment of the business value, technology risk and time to achieve business value.

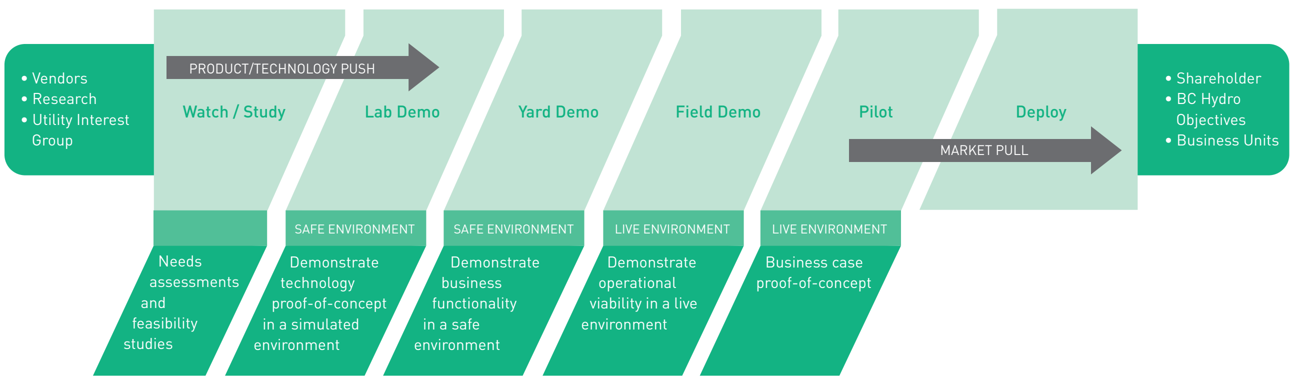


Figure 9: BC Hydro Applied Innovation Pathway

If a technology solution is considered to have value (including risk mitigation) to BC Hydro and is mature enough for deployment, the Technology Group will liaise with the appropriate business unit to deliver the solution using BC Hydro's standard methodology. The Technology Group's architecture and design approach incorporates the principles of end-to-end processes and systems as well as safety, privacy and security included in the design.

Where the pace of technology is moving faster than the organization's ability to manage it (e.g. mobile applications, use of social media), the Technology Group may create a program to rapidly develop capability internally in order to maximize the opportunity. Where an advance in technology appears to offer an opportunity but is not clearly defined, the Technology Group may initiate a program to explore potential use cases and proof-of-concepts (e.g. data analytics). The following areas have been identified as having future high-value potential:

MOBILITY:

Workforce Mobility: BC Hydro is moving toward a fully-mobile workforce. Access to applications on mobile devices will deliver benefits in terms of productivity, safety and improved service delivery. Initial capabilities implemented include Wi-Fi hotspots and laptops in field vehicles and a bring-your-own-device (BYOD) program enabling employees to use their own devices for work and personal use. To support the mobile workforce of the future, the Technology Group has setup a Mobility Centre of Excellence (MCOE) which will work towards development of an "app store" and support the extension of BYOD to tablets and laptops.

Customer Mobility: With over 30 per cent of BC Hydro customers expecting to interact with BC Hydro via mobile devices, BC Hydro must evolve service channel offerings which leverage mobile technologies, and meet customers where they are.

NOW	FUTURE
• Establish Mobility Centre of Excellence. • Identify and prioritize workforce and customer mobility opportunities. • Operationalize core mobility platform.	• Fully integrated mobile business solutions across key business areas. • Mobile business solutions enabled across employees and contractors/service providers. • "Mobile also" strategy in place for all application deployment.

ANALYTICS:

As the volume, variety and velocity of data grow in our system, and computing capabilities continue to increase, it is widely recognized that analytics can play a key role in extracting information that can be used to improve business performance. The Technology Group is developing a data analytics capability that can be exploited by business groups and assist them in meeting their strategic objectives. Leveraging in part the technologies put in place for Theft Analytics in SMI, the initial focus of the Technology Group is providing advanced analytics capability for specific use cases in Safety and Asset Management. This capability will then be expanded to meet the future analytic needs of the enterprise.

NOW	FUTURE
• Extend the Energy Analytics foundation to support feeder and transformer meters and other identified use cases. • Advance pilots to assess capabilities required to streamline business information delivery. • Pilot use of cloud based analytic technologies to support business needs.	• Broadly available business data; Business information and insight delivery streamlined. • Extensive use of analytics driven, fact based decision making across the business. • Mix of on-sight and in-the-cloud based business technology solutions. • Broad availability of geospatially correct asset data. • Predictive analytics integrated with other technology solutions to provide optimal customer experience, relevant solutions and communications.

IT/OT CONVERGENCE AND THE SMART GRID:

Smart Grid technologies (such as Volt-VAR optimization, Fault Location, Isolation and Service Restoration, Distributed Generation, Distribution Automation, and Demand Response) require information and operational technologies (IT and OT) to work together. The Technology Group is building capability in the integration and interoperability of smart grid applications and devices in order to take advantage of future Smart Grid opportunities to improve reliability and efficiency through automation.

NOW	FUTURE
• Continue to support the business in the Distribution. Management System (DMS) implementation project. • Support the business upgrade of the Energy Management System (EMS). • Support the implementation of Intelligent Electronic Device Gateway requirement for Distribution. • Leverage SMI to enable customer-facing solutions.	• Operational integrated systems operations center (iSOC). • Fully implemented EMS and DMS, integrated with Advanced Outage Management functions. • Improved security posture for operational technology assets; Streamlined cyber access to operational devices . • Geospatially accurate GIS including landbase for Generation and T&D. • Support for the 'Connected Customer' for both residential and business customers.

INTERNET OF EVERYTHING (IOE):

There continues to be rapid growth in the number of internet connected devices in our system – including smart meters, intelligent power system hardware, IP cameras, sensors, routers, mobile devices, and networked computers. The interconnection and integration of these devices into our systems, including P-P (person to person), P-M (person to machine) and M-M (machine to machine), will allow for new levels of information sharing, decision making, monitoring and control. The ability to connect and manage these devices requires a sophisticated infrastructure with high capacity/reliability networks, robust operational abilities, new device management applications, big data handling, and an extensive cyber security layer. Much of the foundational infrastructure is in place as a result of the SMI and distribution automation initiatives, but the Technology Group continues to expand BC Hydro's technology capabilities through the introduction of new technologies such as IPV6, MPLS, mobile device management tools, integrated network operations, and advanced analytics.

NOW	FUTURE
• Continued rollout of the Smart Metering Infrastructure (SMI) mesh. • Future proof the network through Internet Protocol version 6 (IPv6) enablement (SMI) and Multiprotocol Label Switching (MPLS) implementation. • Establish telecom Governance function.	• Strategic deployments of sensor technologies to improve real-time asset monitoring. • Real-time visibility into distribution system outages. • Expanding deployment of grid automation technology. • Predictive failure analytics available for critical assets.

EVERYTHING AS A SERVICE (EAAS):

A growing trend is for many IT services to be made available from third party vendors who are able to offer highly virtualized environments that are reliable, low cost, and scalable. Common cloud-type services include Infrastructure as a Service (IaaS which include server and storage components), Platform as a Service (PaaS which include fully provisioned compute environments) and Software as a Service (SaaS which includes fully functional enterprise applications). The KIDC (Kamloops Internet Data Centre) was a major move towards this outsourced model and, although BC Hydro owns much of the computing hardware, it represents a scalable third party managed service. The Technology Group continues to explore other cloud-type services through demonstration and pilots in order to explore efficient approaches to meeting our future IT needs.

NOW	FUTURE
• Highly virtualized infrastructure within Kamloops Internet Data Centre (KIDC), owned infrastructure; Limited virtualization outside primary data center. • Largely manual implementation, operations and disaster recovery solutions. • Non-standardized solution delivery; Limited use of Service Level Agreements (SLA).	• Fully operationalized technology service catalog across owned and cloud based infrastructures; Enforced SLA's across key technology services and service providers. • Highly standardized, automated and orchestrated technology solution delivery and operations; Streamlined and accelerated business solution delivery. • Transparent disaster recovery for key systems and applications. • Services based sourcing agreements.

USE OF SOCIAL MEDIA:

Use of social media is growing as a means of communication and transitioning from the purely social world to the world of business and operations. BC Hydro is starting to use social media for communicating with customers on a very limited basis, while establishing policies and procedures to ensure appropriate use.

NOW	FUTURE
• Limited use of social media services, primarily used for marketing purposes with some targeted outage notification. • Social Networking (e.g., LinkedIn) used in recruiting.	• Broader use of Social Media for customer engagement and interaction including incident and outage reporting. • Social media tools adapted for corporate context to support project needs and stakeholder collaboration and engagement requirements.

TECHNOLOGY OPERATIONS – OPERATING PROGRAM

Technology Operations includes all functions of the Technology Group required to operate, sustain and support information and communications technology systems after implementation.

PROCESSES

The Technology Group uses the standard BC Hydro business management processes for procurement, financial and human resource management. Processes specific to the group include those required to achieve the Technology Group mandate. The Information Management Manual (IMM) and Technology Project Delivery Standard Process Framework (ITDSP) define the processes and standards for BC Hydro information technology deployment. The project delivery framework is aligned with the BC Hydro Project & Portfolio Management (PPM) framework. The widely recognized Information Technology Infrastructure Library (ITIL) framework is used by BC Hydro and most of its IT service providers to deliver help desk, incident management, problem management and service management services. A new capital planning and portfolio management process based on BC Hydro's Capital Allocation Risk Matrix and the Corporate Investment Analysis Guide is in the early stages of implementation. The technology innovation process to build technology capability is defined by the Applied Innovation Roadmap and Innovation Pathway. The enterprise architecture processes and practices follow the internationally recognized TOGAF and Archimate standards. Other less formal processes are in use for business unit relationship management, asset management and resource management. These are the focus of some improvements identified for Fiscal 2015.

RESOURCES: PEOPLE

The Technology Group relies on a multi-service provider model to deliver services for day-to-day operational activities and to deliver on the capital plan. Internal technology resources provide management and oversight for operational and capital delivery functions. Operational activities and sustainment are delivered through internal technology resources and BC Hydro's key service providers TELUS for Tier 1 Help-desk, on-site support, and infrastructure, and Fujitsu for most of BC Hydro's business applications. The Capital projects are delivered by business stakeholders (for business facing projects), key internal technology resources, and external consultants (including TELUS and Fujitsu).

There is significant risk to the Technology Plan due to resource constraints in these four areas:

- Internal technical resources for management and oversight of capital portfolio plan delivery;
- Internal technical resources for increased operational and sustainment activities resulting from the capital plan;
- Internal business resources for definition and oversight of capital portfolio plan delivery; and,
- External technical resources for delivery of capital portfolio plan.

Development of the Technology Plan to date has been in the absence of formal people resource management and planning. The development of a technology resource management plan is in the Action Plan for fiscal year 2015.

RESOURCES: FUNDING

The following table indicates the current funding expectations over the next 5 years. There is a significant risk that sufficient funds to deliver on the plan will not be available, either as capital or as on-going sustainment resulting from the capital spend. The development of an integrated capital planning, resource planning and portfolio management capability is in the Action Plan for fiscal year 2015.

($ MILLIONS)	FY15	FY16	FY17	FY18	FY19
CAPITAL – TECH	$88.4	$95.4	$97.4	$87.3	$89.0
INITIATIVE OPERATING	$8.3	$6.9	TBD	TBD	TBD
BASE OPERATING	$102.3	$105.4	TBD	TBD	TBD
DEFERRED OPERATING	$31.3	$30.8	TBD	TBD	TBD

Note: Resources for fiscal years F17-19, have not undergone regulatory review and are subject to change.

Deferred forecast expenditures consist of SMI and Meter Choices costs, and are expected to be reported as operating expenditures beginning in F2017.

Technology costs charged to Power Smart deferred programs are not included.

Details of the Capital and IOMA resources are included in Section 1: The Portfolio Plan. Details of the Operating and Sustainment resources are included in Section 2: Technology Operations.

The forecasted distribution of technology capital expenditure across business groups and foundation is shown in the following two charts. The first shows the percentage distribution across business groups of the capital dollars forecasted. The second shows the forecast distribution in dollars.

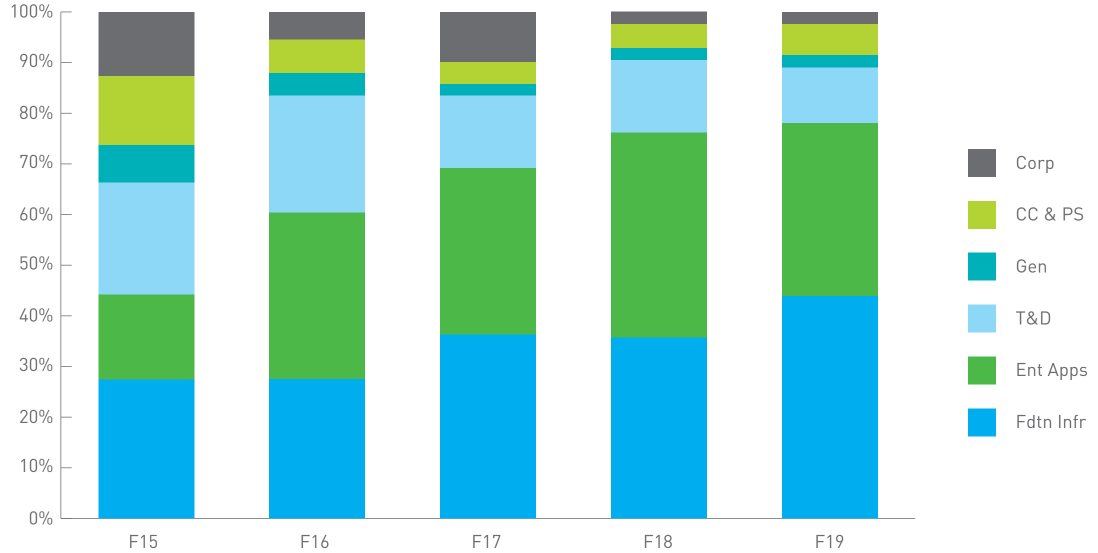


Figure 10: Forecast percentage distribution of technology capital investment

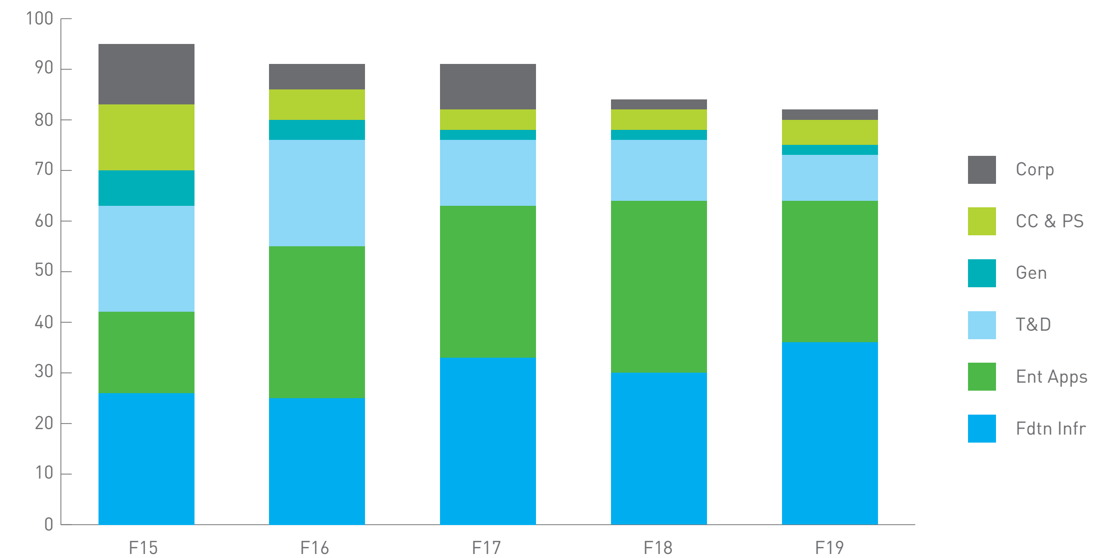


Figure 11: Forecast distribution of technology capital investment in dollars ($M's)

Note that the forecast capital investment at the portfolio level reflects best estimates at May 30th. Figures may differ from the 10 Year Capital Plan however Technology will manage to the approved targets.

PERFORMANCE MEASUREMENT

Opportunities to improve Technology Group performance exist across all functional areas. Current metrics are under revision, however good feedback is available from informal sources, the business unit relationship leads, and technology governance committee. The action plan for fiscal 2015 reflects two specific areas identified for improvement in meeting the needs of the business: coordination of managed services and project delivery.

TECHNOLOGY RISK MANAGEMENT

It is the responsibility of the Technology Group to manage the risk associated with technology for the organization. Risk comes in many forms but can generally be described as:

RISK COMPONENT	MITIGATION
Business Risk: technology solution does not meet business objectives as identified in the business case; business is unable to absorb the process change required to meet the objectives; acceptance of the technology solution is poor and adoption low.	Mitigated through good business process design and a "role-based" definition for the user requirements.
Technological Risk: technology does not perform as expected; technology is too immature for business operations; new technology cannot be integrated with existing legacy systems; old and inflexible technology assets are stranded.	Mitigated through a well-defined architecture, end-to-end systems design and "future-proofing" capabilities. A well planned technology asset management approach supports this risk mitigation.
Performance Risk: systems and technology don't function at an appropriate level of performance or availability.	Mitigated through diligently defining the non-functional requirements of technology solutions, reviewing the solutions end-to-end to understand how individual components interact and through rigorous quality assurance and testing. A test environment has been established and will be expanded to focus on real time systems and 24X7 operations.
Interoperability Risk: technology solution involves multiple service providers whose components all have to work together.	Mitigated through involvement in standards development and completing proof-of-concept projects prior to piloting the technology solution. Complete end-to-end systems designs using a well-defined technology architecture.
Security Risk: includes unauthorized access through firewalls and devices as well as malicious acts internally.	Mitigated through end-to-end risk assessment for each link in the system. Balance probability and impact to deliver the right level of security at the right cost.
Financial Risk: increasing delivery and operating costs from new technology implementations involving more complex software, systems and processes. Includes a requirement for more sustainment, support, software and hardware maintenance, increased licenses and other costs.	Mitigated through optimization of current operational costs, decommissioning digital assets where possible and delivering more advanced operational solutions (e.g. integrated service operations center for telecommunications).
People Risk: headcount and operating cost pressures limit the ability to retain resources with the appropriate capabilities and skills in the technology team and the business end-user experience and knowledge.	Mitigated through focusing resources on key technical work that provides significant job satisfaction. Complete succession planning and proactive recruitment where possible.
Technology Operations Risk: availability, outages, lack of access, business continuity, and disaster recovery. These are complex and difficult systems to operate in a "real time" and 24x7 organization.	Mitigated through a well-planned and structured support organization. Includes use of industry partners and internal resources; highly skilled people in both the business units and the technology group.
Capital Plan Delivery Risk: ability to deliver individual projects and programs as well as cumulative risk to delivery of the portfolio. A large number of "Build" and "Grow" projects that individually have moderate risk can add up to a high level of risk for the Portfolio as a whole.	Mitigated through assessing the capital plan at the business unit portfolio level (for technology, delivery and business risk) and reviewing inter-business unit dependencies. Develop plan based on ability to deliver given people and funding constraints.

ACTION PLAN

Technology has identified an action plan for Fiscal 2015 based on the Capital Plan Portfolio Risk Assessment and Technology group Performance Assessment for Fiscal 2014. The following subset is considered critical to meeting the mandate of Technology:

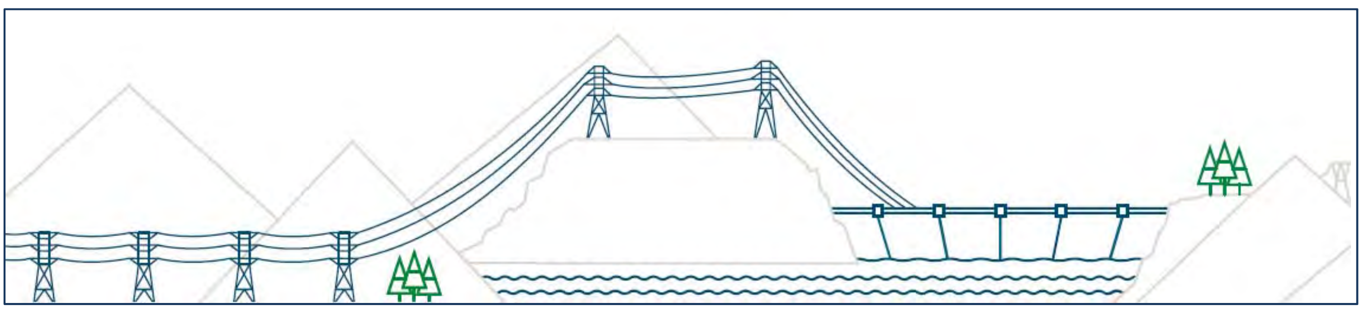
ACTION	OWNER	DUE
Re-assess Business Unit Portfolio Plans based on cumulative portfolio risk, resource and financial constraints	Portfolio Management	Q2 F15
Complete technology systems risk assessment and develop a method for evaluating foundational project proposals based on systems risk	Architecture	Q2 F15
Define plan for implementation of work management and asset management functionality in SAP	Portfolio Management	Q2 F15
Develop integrated portfolio management plan to include capital planning, portfolio selection, resource management, program and project delivery	Portfolio Management	Q3 F15
Develop standard asset management models and tools	All groups	Q3 F15
Establish standard support processes and tools for all support teams	Applications/Technology	Q4 F15
Review and update published technology standards and processes based on current requirements	Architecture/PMO	Q4 F15

The full list of actions is described in Section 2: Technology Operations and in Section 1: The Portfolio Plan.

Technology Group

Five-Year Strategic Plan F17- F21

February, 2016



BC Hydro
Power smart

Contents

INTRODUCTION

Message from Kip Morison

Information and communications technologies (IT) are critical to virtually all aspects of BC Hydro's operations. Whether it be enterprise accounting systems, email, our website, or the use of smartphones, the day-to-day dependency on technology is clear – both for us and our customers. As communications are becoming largely mobile and information digital, the related technologies are becoming essential to field operations and grid operations as well.

This increased dependency on information and communication technologies requires very robust systems and we must focus on delivering reliable, secure and efficient services for BC Hydro. Ensuring our foundational platforms are strong and resilient is paramount as we build new business capabilities.

Over the next five years, our goal is to initiate a renewal of IT, take a business management approach to our operations, and become an efficient and collaborative team able to adapt to change while delivering excellent service.

Technology is essential to BC Hydro's operations and has a huge part to play in achieving our BC Hydro vision. This plan sets out our priorities for the coming years and shows the contribution from Technology in enabling BC Hydro's priorities.

The plan is structured into four sections:

Part 1 – Describes who we are as a team, and the driving factors for technology.

Part 2 – Explains Technology's business operations in line with the five strategic priorities.

Part 3 – Explains Technology's delivery portfolio and how we enable the five strategic priorities.

Part 4 – Identifies Technology's resources and how we measure success.

Kip Morison
Chief Information Officer

PART 1 – CONTEXT

Our Mission, Our Vision, Our Values and Our Five Priorities

BC Hydro's "*Our Plan to Guide Our Work*" published in September 2015 sets out our Mission, our Vision, our Values and our Five Priorities.

OUR MISSION

To provide **reliable**, **affordable**, **clean** electricity throughout B.C., **safely**.

OUR VISION

To be the most **trusted, innovative** utility company in North America by being smart about power in all we do.

OUR FIVE PRIORITIES

Make it easy for customers to do business with us

Deliver capital projects on time and on budget

Explore the full potential of energy conservation

Strengthen our proud and valued workforce

Continue to improve the way we operate

OUR VALUES

We are safe

We are here for our customers

We are one team

We act with integrity

We respect our province

We are forward thinking

Who We Are

The Technology Group has an essential role in enabling our business partners to achieve BC Hydro's strategic priorities. Our goal is to provide the best possible Information and Communications Technology (IT) services based on our values.

- We enable BC Hydro's business goals; information and communications technologies are essential to delivering BC Hydro's vision and priorities.
- We enable our business partners to be more productive and work smarter. We make it easy for customers to interact and transact with us. Our field workforce have new and better tools to do their jobs more productively and safely. We provide access to data in support of managing our business and our conservation goals.
- We are adaptable and can respond to changing business conditions and provincial policy directions.
- We respond to challenges and aim to continue critical services under all circumstances. Our business partners and customers expect services to be available when they need them.
- We protect and value the integrity and safety of information about British Columbians for which we are the stewards. Our information and operating systems are resilient to cyber attacks.

- We are committed to continuous improvement, managing our services as a business and providing the highest value for the right cost. Our investments in technology will be in line with the BC Hydro 10 Year Capital Forecast. Our operating spend will match the expectations and efficiency targets of BC Hydro.
- We are building the service delivery capability we need to competently govern and manage our outsourced services.
- We make use of opportunities available through technology agreements with the Province. We act in the best interest of the citizens of BC.
- We will use a risk-based prioritization to managing our IT assets and systems. Risk based decisions are communicated and understood.
- We operate and maintain our IT assets to the best of our ability. We are proud of our systems and the services we provide for our users.
- We are committed to being a good place for IT professionals to work.

To be effective in our delivery of IT services we must take a business management approach, identify the needs of our business partners, develop and maintain relationships, provide consistent, reliable service and value-add, measure our performance, and strive for continuous improvement.

Over the next five years we will become a smoothly running team able to adapt and change while delivering excellent service.

Driving Factors for Technology

Information and communications technologies are essential to business operations. As communications become largely mobile and information digital, IT technologies also become essential to field operations and grid operations. Technology is changing the way we work at an increasing rate, bringing us new capabilities and the ability to work more effectively.

Expectations from customers and our internal users are high based on technologies available to consumers such as smartphones, tablets, online services and social media. Familiarity with these technologies, outside of the work place, often act as inspiration for ways to achieve our strategic priorities. The enterprise market has traditionally lagged behind the consumer market but the next five years will see the steady maturity of enterprise-ready solutions able to exploit cloud-based systems, mobile solutions, analytics, and advanced automation and control. In the coming years we must be ready to take advantage of the opportunities these advances bring.

This year we will initiate the renewal of IT through,

- Achieving efficiency targets in operations through robust work planning, investment prioritization based on value and risk, benefits tracking, focusing on core functions, and aligning our delivery model with business needs
- Enabling key strategic initiatives in the business including supply chain, customer billing and field worker mobile device deployment
- Increasing the resilience of our systems through a risk-based approach to architecture, replacement, recovery and security
- Building an engaged and balanced team with the skills to support our service delivery objectives

Over the next five years we will,

- Continue to enable our business partner’s priorities including improved work methods, customer experience, advanced mobile capabilities for field workers, and access to information for smarter, quicker decision making

- Develop an operating model that allows us to meet our efficiency targets, enable our business priorities as well as maintain and support robust core systems
- Continue to balance our investment in new business initiatives with the need to maintain a robust information and communications technology foundation
- Implement integrated planning with our business partners and improve how we communicate and prioritize work
- Adapt the way we operate to provide the best service at the right cost
- Implement continuous improvement toward service excellence in performance, availability, and reliability
- Implement a robust and integrated cyber security model
- Use advances in technology to meet our performance objectives, enable our business priorities as well as maintain and support robust core systems

Our plans for new technologies will be developed based on BC Hydro's strategic direction and a risk-based asset investment strategy. Early pilot projects in mobile device applications and cloud solutions will be followed by further investments in platform and application services. Our business is dependent on our information and communications technology systems. While enabling new business initiatives is core to our service delivery, so is operating, maintaining and refreshing our critical systems and platforms. These include email, web platforms, office tools, remote access, mobile device platforms, call centre, outage management, financial, supply chain, planning and engineering design systems. To help guide investment choices, we use a set of principles that balance the needs of our business partners with the need to maintain performance, reliability, security and efficiency in the enterprise systems. These principles include,

- Assess technology investments based on the expected value and benefit to business initiatives.
- Balance cost, benefit and risk across the whole technology environment through architecture planning and standard designs.
- Balance technology investments between strategic and tactical solutions to maintain a robust information and communication technology foundation.
- Test and validate current technology investments before investing in new.
- Avoid creating overlapping or redundant processes and systems.
- Establish "authoritative source of truth" information stores, through systems-of-record.
- Embed cyber security in all technology strategies, architectures and designs.

Over the next five years we will continue to invest in business solutions, foundational technology assets and emerging technology pilot programs in all five priority areas. The diagram below illustrates these investments.

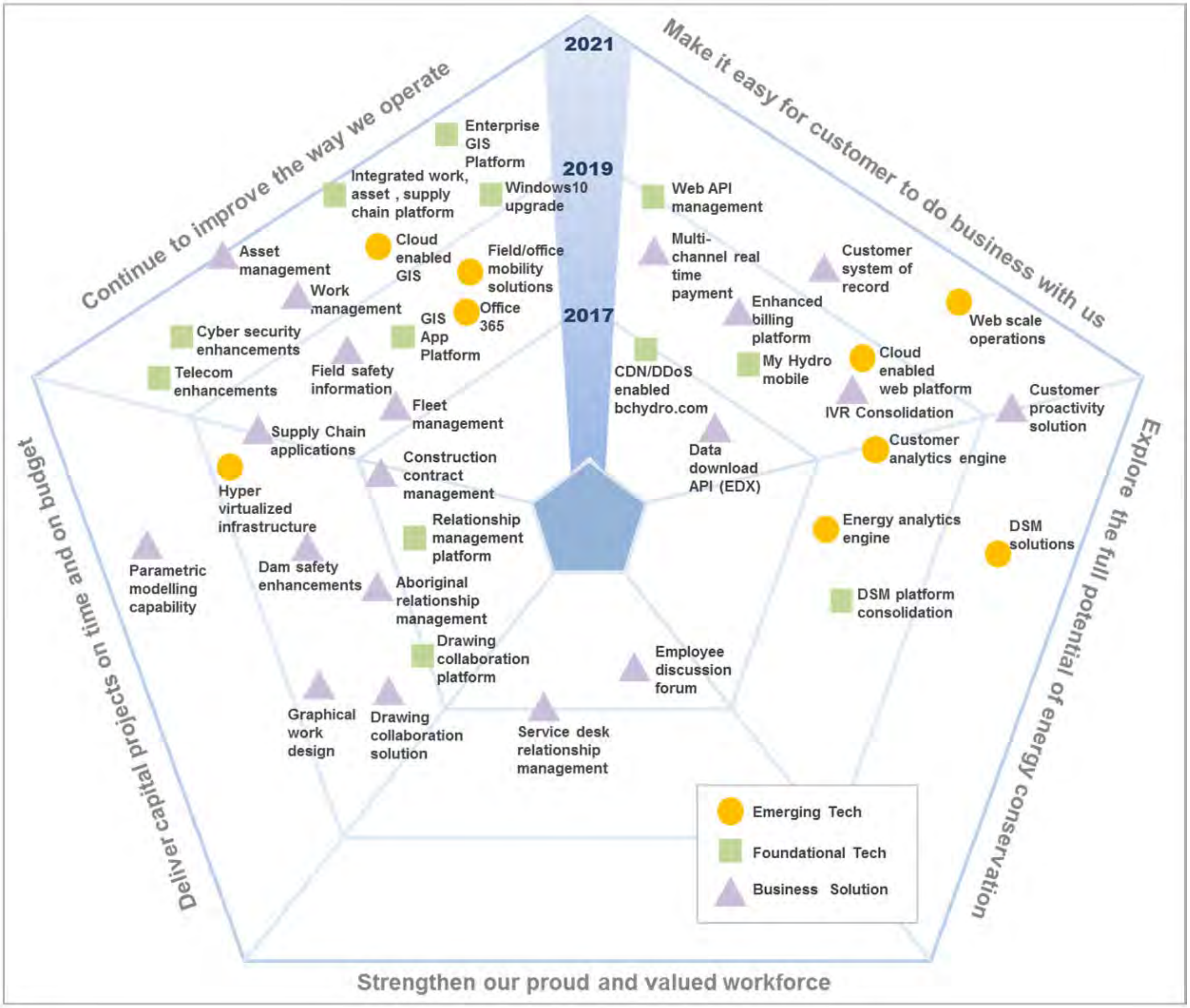


Figure: Roadmap for investment in information and communications technologies F17-F21

PART 2 – Technology Group Business Operations

Make it easy for customers to do business with us

In Technology our customers are our business partners, contractors and others that use BC Hydro information and communications technology systems and equipment. Our goal is to provide a service that is useable, accessible, reliable and available. Beyond this we are adaptable to business needs, able to provide innovative solutions and take advantage of advanced technology as it comes to market. We strive to provide,

- Outward facing systems that make it easy for BC Hydro customers to interact and transact with us.
- User support systems that are simple, easy to use and available to our business partners.
- Newer and better IT tools for our workforce so they can do their jobs more productively and safely.
- Access to data for our business partners as and when needed
- Internet-based and mobile solutions for customers and field workers to enable access anytime and anywhere.

Technology has a key role to play in delivering the technology solutions required for BC Hydro's customer strategy. This role is described in Part 3: Technology Delivery Portfolio.

Help desk and user support services

This year improvements to our information technology service management tools and processes will make our support staff better able to support our users. More self-service options will become available and interfaces more useable and uniform. We will continue to improve our user communications on IT planned and unplanned outages as well as ensure our service levels align with user expectations. The next five years will see more bring-your-own-technology opportunities (beyond the current bring-your-own-device program) as applications and services become less platform reliant and enterprise-ready cloud services more available.

Integrated business planning

To be responsive to our business partners we must match our plans to theirs. Business initiatives not only drive capital investments but the need to build or source new technology capabilities. Understanding our business partners' strategic plans will allow us to better plan our service provision. This year we will continue to collaborate with our business partners to build plans that reflect the interdependencies between groups and that support our business priorities.

Data access and information

Information technology is all about information and data. Providing access to the right information at the right time helps customers and business people alike stay informed and make smarter decisions. This year we will focus on our process for data access requests. In the next five years, our focus will be to make it easier to request, receive, and process data into consumable information.

Access to newer and better tools

We will strive to provide new and better tools to our users through disassociating the traditional requirements of the enterprise from the interfaces for the user. We will look to the market to provide the right tool for the job and manage the integration risk. This year we will give our workforce access to a smart device and information to improve safety, optimizing our mobile radio network and deploying a refreshed laptop and desktop image. In the next five years, we will explore virtual desktops, office applications-as-a-service and mobile applications to simplify information gathering, improve productivity and provide the right tool for the job.

Deliver capital projects on time and on budget

Technology is responsible for BC Hydro's capital budget allocated to information and communication technology investments. Our role is to manage the budget, aid in prioritization of investment and oversee implementations of technology to enable our business partners to deliver on our strategic priorities. In this role,

- We are a partner to the Business; an active player in the selection, integration and execution of information and communiction technology capital projects.
- Our outsourced providers are able to contribute to delivering and understanding how to best use market ready and reliable technology to meet business needs.
- We are able to adapt to changing business priorities and propose optimal solutions.
- We select the best delivery model for the job and continually strive for delivery excellence.
- In addition to on-time and on-budget we emphasise value, fit and quality of our solutions.

Choosing the right delivery approach

To deliver our capital portfolio, we need to choose the best approach for the task at hand. This might mean choosing an external vendor, one of our existing outsourced service providers, or an internal delivery team augmented with contracted resources. For complex projects, it may be a combination of all three. Whatever the approach we will need skilled internal people in critical roles. This year, our goal is to start developing strong capabilities in resource planning and vendor management for project delivery. In the next five years we will continue to strive for project delivery excellence.

Investment management

We are entrusted with the capital budget for implementing information and communications technology investments. Our role is to ensure that our investments are wisely made and give the greatest value in achieving our business objectives. This includes prioritizing strategic business initiatives and foundational improvements. This year our focus will be on improving our prioritization and selection process in order to get the best mix of investment in foundational and business solutions. We then guide these investments through project delivery for the best outcomes and greatest value for BC Hydro. In the next five years, we must measure our investment performance, track the realized benefits and incorporate learning into future investment decisions. Tracking benefits will also provide information for recovering sustainment costs.

Explore the full potential of energy conservation

Our role is to support the business in providing the tools and information to our customers that will allow them to make optimal energy choices. We support this business priority through our capital project portfolio. In addition, we will continue to monitor our own use of energy and optimize where possible. The Technology group,

- Will contribute to raising the bar on providing access to data and information used by consumers to manage their consumption of energy.
- Will continue to monitor and reduce energy use of our technology infrastructure where possible.

Access to data
In support of this priority, we will strive to provide the right level of access to data and data analytics solutions. This year the focus is on improving our data access service with the technology solutions we have today. In the next five years we plan to deploy a new platform for our core systems that will improve processing time and allow analytics against a transactional system. This will simplify access to data and allow our business partners faster and better access to data. We continue to use our architecture to promote single systems-of-record and access to data via an enterprise service bus.

Optimal use of assets
Data centre servers and other technology assets are heavy users of energy. Our data centre is state of the art in terms of optimal use of energy. As we continue to grow our asset base, we will ensure the use of virtual server technology as much as possible, consolidate our footprint and utilize joint-use infrastructure where it make sense. This year we will benchmark our energy use and over the next five years continue to track our energy footprint.

Strengthen our proud and valued workforce

Our people are our strength and Technology aims to be a great place for professionals to work. However, with continued demand for technology services, the team is experiencing a lack of capacity to deliver on the full capital plan, exposures to service issues in system operations, and a serious employee workload problem. To provide the best service within operational constraints, we must make some bold changes in our delivery resource model and organizational structure. We will,

- Create an organizational structure best able to support our service delivery objectives
- Build an engaged and balanced team with the appropriate skills
- Develop a vendor management capability to match our service delivery model

Service delivery model

This year we will complete the delivery model and sourcing strategy. This project will design a delivery model that fully supports our service objectives and allows for the greatest flexibility in changing technology and business needs. We expect to continue with a certain level of outsourcing which will require an organizational structure as well as a service integration and vendor management capability to support the model. This year we will complete the development of the strategy. Over the next five years we will implement the strategy.

Team work

The focus this year is to work as a team to deliver the best service possible to our business partners. With limited resources, we will need to decide together where we can create the greatest value and collaborate on planning and prioritizing. This requires the team to take a business management approach to technology services: identify the needs of our business partners; develop and maintain relationships; provide excellent service; deliver consistency, reliability and value-add; measure our performance; and strive for continuous improvement. Over the next five years, our goal will be to become a smoothly running team able to adapt and change at the same time as deliver excellent service.

Build capability

Following the completion of the delivery model strategy, we will focus on building the skills needed to support our service model. We will focus on internal people in critical roles anddetermine the most effective balance of roles that should be insourced and roles that should be outsourced. We will need to build strong capability in integrated service management and vendor management in order to support the selected delivery model. This year we will identify the roles and start to develop the capabilities required to support the strategy. Over the next five years we will continue to build and develop the required capabilities.

Build a great place to work

This year the focus is on improving areas identified by the employee survey results. We will make a targeted effort to address workload, training and opportunities for growth. Over the next five years we will strive to create an engaged, balanced and skilled team with the tools it needs to deliver excellent service. Our team must feel empowered, listened to, and free to speak up. Our environment must be open, collaborative and a great place to work.

Continue to improve the way we operate

Technology is experiencing constant operating cost pressures due to inflation, heavy dependency on information and communication technologies and increased expectations from business partners and customers for technologies available in the consumer market. Implementing for the enterprise requires greater levels of performance, security, privacy and reliability as well as access to secured back office systems. Technology must take steps to optimize operations, becoming as efficient as possible without impacting service to our business partners and our customers. We must become financially transparent, develop a catalogue of services, and track IT benefits in order to effectively manage increasing costs. A fundamental operating model change is required to meet the increasing pressures related to,

- Increasing expectations from the business and customers
- Increasing dependence on information and communications systems for all operations
- Inflationary pressures and exchange rate fluctuation on items like software licenses and equipment
- Increasing sustainment costs as capital projects continue to be delivered and the size of he portfolio grows
- Advances in technology making infrastructure and tools obsolete in a matter of years

Finding efficiencies

For the next two years we will focus on optimization and finding efficiencies, making sure we are doing the right work at the right time for the greatest value. Using this efficiency program, we will find a savings of 5% per year in the next two years. This year we will complete a detailed operating budget plan aimed at reducing expenditure and prioritizing high-value activities. We will review our endpoint device allocation and policy, review our networks and infrastructure for inefficiencies, and review non-core functions for consolidation within the broader organization. Over the next five years, we will look at ways to change the operating model in order to effectively manage sustainment costs based on capital project benefits and added-value service costs.

Service and business management approach to technology

To be effective in our service delivery model we must take a business management approach: identify the needs of our business partners; develop and maintain relationships; provide excellent service; deliver consistency, reliability and value-add; measure our performance; and strive for continuous improvement. This year we will focus on our organization and clearly defined responsibilities. Over the next five years, our goal will be to become a smoothly running team able to adapt and change at the same time as deliver excellent service.

Operating model changes

Efficiencies and optimal delivery will only bridge the gap between our operating costs and budget for the next two fiscal years. A change to our operating model is required to allow us to sustain new investments by recovering some of the business benefits. This year we will focus on identifying our service costs and implementing benefits tracking. Over the next five years, we will introduce a service catalogue to give financial transparency to our business operations.

Risk management

Our business is dependent on our IT systems. Operating, maintaining and refreshing our critical systems and platforms is core to the service we provide. Critical systems include email, web platforms, office tools, remote access, mobile device platforms, call centre, outage management, financial, supply chain, planning and engineering design systems. We are also responsible for records management and retention policies. This year we will develop an asset health index and risk management approach to improve the robustness, availability, ability to recover, and security resilience of our most critical systems and records. In the next five years, opportunities to improve availability, recovery or performance through newer market offerings, such as cloud service provision, will be taken where appropriate.

PART 3 – The Technology Group's Delivery Portfolio

Make it easy for customers to do business with us

Technology is central to this objective as customer and vendor expectations for digital communication channels and electronic documentation continues to grow with advances in consumer technologies. Technology projects are adding benefits such as reducing paper bills, allowing customers to use mobile devices to interact with BC Hydro, and improving the customer call centre. In future years, new customer self-service options will be added providing customers with increased control of their accounts and in-home energy management devices. The Customer Strategy program requires investment in technology solutions including,

- Customer bill redesign
- Contractor portal and workspace
- More customer payment options
- Customer portal enhancements to improve customer experience and self-service capabilities
- Call centre call handling improvements

Customer billing and service

The focus for this year is on redesigning the customer bill, allowing payment through direct debit and allowing customers with multiple accounts to view three years worth of consumption and billing data. In addition there will be easier self-service through the call centre interactive voice response (IVR) and through the bchydro.com website. Customers will soon be able to select their preferred channel for engagement and have payment options through their mobile device; we will begin to more widely leverage social media channels for the benefit of the customer. In the next five years, we will implement a customer centric view of all BC Hydro interactions and integrated self-service across all channels.

Vendor contracting and billing services

Many vendors are now able to submit invoices and receive purchase orders and contracts electronically, making the process more efficient and allowing them to receive payment sooner. Enhancements to the e-commerce platform allow mid-to-small size vendors to participate without costs to themselves and vendors to receive quicker payment when offering BC Hydro a discount. This year an increasing number of vendors will be able to view and update their own information electronically. In the next five years, the goal for Supply Chain is to have a high number of vendors interact with us electronically.

Relationship management

This year, we are building a foundation platform to support multiple relationship management needs from our business partners including aboriginal relations, customer service, service desk and others. In the next five years this platform will provide the foundation on which to improve our interactions with our customers, First Nations, and internal users.

Technology support services

Over the next five years we will continue to provide services in support of this strategic objective including operation, maintenance and minor enhancements for: call handling applications, CR&B (Customer Relations & Billing) system, customer portal and bchydro.com websites, mobile ambassador application, metering data management, load analysis, revenue assurance applications, outage notification systems and enhanced e-commerce platform and services.

Deliver capital projects on time and on budget

Information technology solutions provide the tools needed by the capital delivery groups to be as effective and efficient as they can be. These tools are broad in scope and application as they cover the full lifecycle of capital project delivery. Work in support of BC Hydro's capital delivery includes,

- Construction Contract Management (CCM) upgrades, enhancements, integration and support
- Project and Portfolio Management (PPM, including Primavera P6) upgrades, enhancements and support
- Supply chain implementation and integration
- Aboriginal Inclusion Reporting System
- Fish and Wildlife Compensation Program
- Design and drawing collaboration workspace
- 3D modeling capabilities
- Dam safety information systems

Supply chain improvement
This year we are starting a large and complex project to replace the remainder of BC Hydro's legacy supply chain systems with our SAP solution. This multi-year effort will continue to implement Supply Chain's strategic vision to create direct process integration with existing SAP modules. In the next five years we will have new functions including material and service demands, procurement, contract and category management, inventory management and accounts payable.

Drafting and design capability
This year we will improve our ability to collaborate on engineering designs as well as digitally design in three-dimensions. These tools are required to support the outsourced delivery model in use for all of our large capital programs including site C, and our role as owner's engineer. Over the next five years will see fully integrated multi-discipline engineering design and the use of three dimensional parametric tools.

Construction and contract management
A large part of managing capital projects is construction and contract management. This year we will continue to support improvements in process and tool enhancements. In the next five years we will explore the benefits from tools to support asset investment management and portfolio prioritization.

Technology support services:
This year Technology continues to support and maintain the applications critical to ensuring transmission and generation assets are properly maintained, planned and built to meet the electricity demands of the Province. They include: Construction Contract Management, Project and Portfolio Management, Aboriginal Inclusion Reporting System, 3D modelling capabilities, drawing and design collaboration workspace, Dam Safety Information System, and Reservoir Slope Information System. In the next five years there are plans for upgrades, enhancements, and integration for these systems.

Explore the full potential of energy conservation

Information technology enables conservation through tools that give visibility to energy use and promote optimal use of energy resources. These tools range from customer mobile device solutions to complex, process-heavy generation resource management tools,

- Energy insights gives customers visibility to their energy consumption
- Energy resource planning and management
- Energy Planning Information Central (EPIC) long-term planning tool
- Commercial building energy management programs supported by Portfolio Manager

Customer energy conservation and management

Over the next five years we will continue to develop platforms for smart meter data analytics. The implementation of an Energy Insights application (available on mobile devices) takes consumption data and feeds it back to the customer providing an opportunity to participate in programs and modify behavior patterns. This year we will simplify enrolment to energy conservation programs and provide a single view to customers of all programs for which they are eligible. In the next five years we will include exploration and development of tools to help customers make energy management decisions, support demand side management programs including customer alerts, and provide central enrolment and coordination of all customer facing programs.

Energy planning

This year enhancements will be made to applications required to provide a structured management framework (both short-term and long-term) to balance the BC Hydro energy portfolio, bringing in Independent Power Producers (IPPs) to complement our internal energy sources. Over the next five years we will continue to support and enhance these systems.

Technology support services

Over the next five years Technology will continue to operate, maintain and provide enhancements for meter data analysis and management systems, customer facing information on energy use, energy conservation programs, energy source planning tools, IPP contract management applications, and transmission and distribution planning tools.

Strengthen our proud and valued workforce

Technology helps to foster engagement in the workforce through the provision of collaboration and communications technologies. These include email, chat, video conferencing systems, mobile devices and remote connectivity as well as ensuring that all employees have access to engagement forums such as safety calls and hydroweb. Technology provides,

- Systems for succession and performance management
- Employee communication and engagement tools

Training, performance management and succession

This year we will continue to support and enhance our existing systems. Over the next five years we will explore the expansion of the SAP Human Capital Management (HCM) footprint, potentially moving functions such as employee performance and goals, compensation and succession management, recruitment and onboarding and training to the cloud, with a focus on retiring remaining legacy and stand-alone systems. Priorities are improved usability and mobile access to all core employee and training functionality.

Communication and engagement

This year the focus is on completing the deployment of smart phones to all field workers and looking at opportunities to utilize cloud and social media services to provide better communication services and better employee engagement. Over the next five years we will continue to explore opportunities for employee engagement as new technologies develop.

Technology support services

Over the next five years, the Technology Group will continue to operate, maintain, provide upgrades and security services for all BC Hydro's email and instant messenger applications, conference room and tele-conference equipment and collaboration tools. We also maintain and support all human resource software applications including OPPRA, QLMS, SAP Careers and Job Postings.

Continue to improve the way we operate

Information technology systems have a long history of providing process improvement through communication, information availability, data capture and analysis, workflow management and tools that provide visual instruction and feedback. In the next five years we will use technology to support operational functions including,

- Safety systems and smart phones
- Work management
- Asset management
- Reliability-centered maintenance
- Mobile inspection and data capture capabilities
- Generation operations system improvements and optimization

There are multiple opportunities to improve the way we work with new, faster and more user intuitive technologies. These range from simple re-designs to integrated systems, augmented and virtual reality. Our challenge is to manage the pace of change so as not to put operations at risk but good opportunities exist to use software-as-a-service for applicaitons that require no integration with our back-end systems.

Generation resource management (GRM) and operations

The focus this year is to reduce processing time for some of the GRM applications from days to hours. In addition, simulation and modeling tools will be enhanced to use probabilistic analysis rather than fixed input parameter ranges, giving a more realistic outcome. Over the next 5 years we will take advantage of cloud processing power as well as migrate applications to modern, supportable platforms. The focus in future years is continuous improvements to generation operations systems, energy management applications and forecast modelling.

Transmission and distribution productivity improvement

This year our focus is on delivering on our capital projects such as graphic work design. The next 5 years include some major initiatives: extending distribution work scheduling to transmission, distribution work management, asset management and analytics systems to improve resource planning and work management. Work scheduling and work management offer opportunities for productivity improvements with less travel time and better intelligence on job requirements.

Improve safety

The focus this year is on development of a digital library and work flow to support the Safety Management system. Over the next five years we will continue to support BC Hydro's Safety team in achieving our safety goals.

Field mobility

The focus this year is to ensure all field workers have a smart phone and standby managers have access to information stored on sharepoint via a mobile device when on-call. Field worker applications for mobile devices aim to boost productivity, safety and work quality in the field. Over the next five years field workers will have mobile applications for data capture and work management. Future integration with our operational systems will allow for more real-time, intuitive and visual information in the field.

Technology support services

Over the next five years, the Technology Group will continue to operate, maintain, provide upgrades and security services for all BC Hydro's business information systems used by all of our finance, properties, safety, operations, engineering, planning and design groups. Technology also procures, deploys, supports and maintains all hardware and software for employee devices including laptops, tablets, rugged laptops, mobile phones and radios.

PART 4 – TRACKING OUR PROGRESS

Metrics

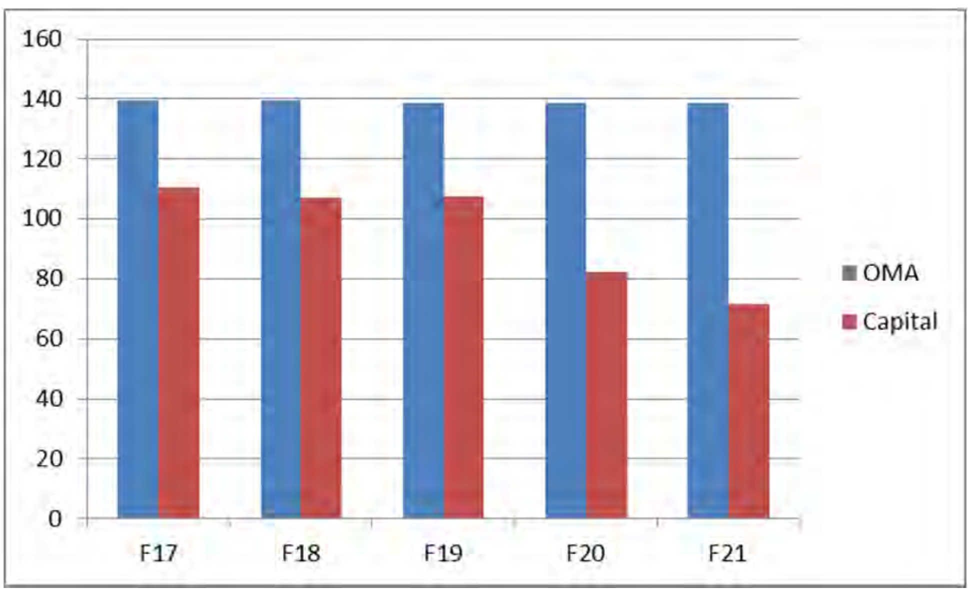
The Technology Group is in the process of developing new metrics that reflect our goal to work as a **team**, provide excellent **service**, be **efficient** in our operations and provide innovative, quality solutions.

Metrics may include,

Service	Team	Efficiency
• Business partner satisfaction • Availability of core systems • Benefit to the business of technology investment • Reduction in cyber security risk	• Workload scores • Work satisfaction • Professional development	• Core operations costs • Risk rating of critical systems • Delivery to estimates

Financial resources

The Technology Group has both a capital and operating budget. The following chart provides an estimate of the total capital and operating budgets for the next 5 years. Details of these budgets are documented in BC Hydro's 10 Year Capital Forecast and Revenue Requirements Application for F17-F19.



Footnotes:
1. F17-F19 are portfolio plan amounts (based on the RRA preparation w/ currency date of Aug 31, 2015).
2. F20-F21 are portfolio forecast amounts, scaled uniformly so inflation-adjusted total matches 10 Yr Capital Forecast.
3. Inflation rate used is 2%.

126.0 Reference: Exhibit B-6, CEC 1.61.1

1.61.3 To what extent does BC Hydro typically require its Technology project benefits to be 'monetizable'? Please discuss.

RESPONSE:

BC Hydro requires that all Technology projects identify the benefits that are expected to be realized by the organization. These could include both financial and non-financial benefits.

BC Hydro considers a "monetizable" benefit to be one that can be converted to actual operating or capital cost reductions.

Not all projects are expected to have monetizable benefits. For example, projects categorized as having compliance or risk reduction drivers are unlikely to have monetizable benefits. Such projects are typically needed in order to meet regulatory requirements, comply with software license agreements, replace obsolescent equipment, add infrastructure capacity, or address various business risks. The benefits of these projects are likely to be avoided future costs rather than actual cost reductions.

For projects to enhance business capability, it is expected that there will be financial benefits and that these benefits will either be monetizable or result in avoided costs. Recent examples include the Enterprise Billing Project, discussed in BC Hydro's responses to BCUC IRs 1.114.1 and 1.114.2 and the Supply Chain Applications Project, discussed in the Supply Chain Applications Project Phase Two Verification Report filed with the BCUC on October 12, 2018.

2.126.1 Please confirm that 'avoided costs' is a relative term, and exist only when comparing one business outcome from another.

RESPONSE:

Confirmed. BC Hydro defines "avoided costs" as prevented or reduced future costs relative to what would otherwise be incurred under a status quo or other plausible course of action.

126.0 Reference: Exhibit B-6, CEC 1.61.1

1.61.3 To what extent does BC Hydro typically require its Technology project benefits to be 'monetizable'? Please discuss.

RESPONSE:

BC Hydro requires that all Technology projects identify the benefits that are expected to be realized by the organization. These could include both financial and non-financial benefits.

BC Hydro considers a "monetizable" benefit to be one that can be converted to actual operating or capital cost reductions.

Not all projects are expected to have monetizable benefits. For example, projects categorized as having compliance or risk reduction drivers are unlikely to have monetizable benefits. Such projects are typically needed in order to meet regulatory requirements, comply with software license agreements, replace obsolescent equipment, add infrastructure capacity, or address various business risks. The benefits of these projects are likely to be avoided future costs rather than actual cost reductions.

For projects to enhance business capability, it is expected that there will be financial benefits and that these benefits will either be monetizable or result in avoided costs. Recent examples include the Enterprise Billing Project, discussed in BC Hydro's responses to BCUC IRs 1.114.1 and 1.114.2 and the Supply Chain Applications Project, discussed in the Supply Chain Applications Project Phase Two Verification Report filed with the BCUC on October 12, 2018.

2.126.2 Please confirm that avoided costs refer to real savings that are anticipated from avoiding future spending.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.126.1 where we define "avoided costs" as prevented or reduced future costs relative to what would otherwise be incurred under a status quo or other plausible course of action.

Commercial Energy Consumers Association of British Columbia Information Request No. **2.126.3** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

126.0 Reference: Exhibit B-6, CEC 1.61.1

1.61.3 To what extent does BC Hydro typically require its Technology project benefits to be 'monetizable'? Please discuss.

RESPONSE:

BC Hydro requires that all Technology projects identify the benefits that are expected to be realized by the organization. These could include both financial and non-financial benefits.

BC Hydro considers a "monetizable" benefit to be one that can be converted to actual operating or capital cost reductions.

Not all projects are expected to have monetizable benefits. For example, projects categorized as having compliance or risk reduction drivers are unlikely to have monetizable benefits. Such projects are typically needed in order to meet regulatory requirements, comply with software license agreements, replace obsolescent equipment, add infrastructure capacity, or address various business risks. The benefits of these projects are likely to be avoided future costs rather than actual cost reductions.

For projects to enhance business capability, it is expected that there will be financial benefits and that these benefits will either be monetizable or result in avoided costs. Recent examples include the Enterprise Billing Project, discussed in BC Hydro's responses to BCUC IRs 1.114.1 and 1.114.2 and the Supply Chain Applications Project, discussed in the Supply Chain Applications Project Phase Two Verification Report filed with the BCUC on October 12, 2018.

2.126.3 Please provide a ball park estimate of the proportion of technology projects that are justified primarily on the basis of avoided costs.

RESPONSE:

BC Hydro clarifies that while some technology investments may result in avoided cost benefits, this does not mean that those investments are justified primarily on the basis of avoided costs.

BC Hydro's technology investments are categorized as managing compliance and security, managing risk and sustaining productivity or enhancing business capability. The drivers for investments in each of these categories are shown in Table 6-51 of Chapter 6 of the Application. Avoided costs are not identified as a driver for any of the investment categories.

126.0 Reference: Exhibit B-6, CEC 1.61.1

1.61.3 To what extent does BC Hydro typically require its Technology project benefits to be 'monetizable'? Please discuss.

RESPONSE:

BC Hydro requires that all Technology projects identify the benefits that are expected to be realized by the organization. These could include both financial and non-financial benefits.

BC Hydro considers a "monetizable" benefit to be one that can be converted to actual operating or capital cost reductions.

Not all projects are expected to have monetizable benefits. For example, projects categorized as having compliance or risk reduction drivers are unlikely to have monetizable benefits. Such projects are typically needed in order to meet regulatory requirements, comply with software license agreements, replace obsolescent equipment, add infrastructure capacity, or address various business risks. The benefits of these projects are likely to be avoided future costs rather than actual cost reductions.

For projects to enhance business capability, it is expected that there will be financial benefits and that these benefits will either be monetizable or result in avoided costs. Recent examples include the Enterprise Billing Project, discussed in BC Hydro's responses to BCUC IRs 1.114.1 and 1.114.2 and the Supply Chain Applications Project, discussed in the Supply Chain Applications Project Phase Two Verification Report filed with the BCUC on October 12, 2018.

2.126.4 Please confirm that avoided costs are only legitimate when an analyst can credibly prove that a cost will definitely follow absent the proposed project.

RESPONSE:

Avoided costs are only considered when there is sufficient information available to support the assumption that the prospective costs will follow absent the proposed project.

Commercial Energy Consumers Association of British Columbia Information Request No. **2.126.5** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

126.0 Reference: Exhibit B-6, CEC 1.61.1

1.61.3 To what extent does BC Hydro typically require its Technology project benefits to be 'monetizable'? Please discuss.

RESPONSE:

BC Hydro requires that all Technology projects identify the benefits that are expected to be realized by the organization. These could include both financial and non-financial benefits.

BC Hydro considers a "monetizable" benefit to be one that can be converted to actual operating or capital cost reductions.

Not all projects are expected to have monetizable benefits. For example, projects categorized as having compliance or risk reduction drivers are unlikely to have monetizable benefits. Such projects are typically needed in order to meet regulatory requirements, comply with software license agreements, replace obsolescent equipment, add infrastructure capacity, or address various business risks. The benefits of these projects are likely to be avoided future costs rather than actual cost reductions.

For projects to enhance business capability, it is expected that there will be financial benefits and that these benefits will either be monetizable or result in avoided costs. Recent examples include the Enterprise Billing Project, discussed in BC Hydro's responses to BCUC IRs 1.114.1 and 1.114.2 and the Supply Chain Applications Project, discussed in the Supply Chain Applications Project Phase Two Verification Report filed with the BCUC on October 12, 2018.

2.126.5 Please confirm that BC Hydro quantifies and provides substantive documentation for the 'avoided future costs' in all financial decisions that rely on avoided costs for financial justification.

RESPONSE:

BC Hydro's technology investments are categorized as managing compliance and security, managing risk and sustaining productivity or enhancing business capability. The drivers for investments in each of these categories are shown in Table 6-51 of Chapter 6 of the Application. Avoided costs are not identified as a driver for any of the investment categories.

Where there is sufficient information available to support the assumption that future costs will be prevented or reduced relative to what would be incurred under a status quo or other plausible course of action, then these avoided costs may be documented in the business case.

Commercial Energy Consumers Association of British Columbia Information Request No. **2.126.6** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

126.0 Reference: Exhibit B-6, CEC 1.61.1

1.61.3 To what extent does BC Hydro typically require its Technology project benefits to be 'monetizable'? Please discuss.

RESPONSE:

BC Hydro requires that all Technology projects identify the benefits that are expected to be realized by the organization. These could include both financial and non-financial benefits.

BC Hydro considers a "monetizable" benefit to be one that can be converted to actual operating or capital cost reductions.

Not all projects are expected to have monetizable benefits. For example, projects categorized as having compliance or risk reduction drivers are unlikely to have monetizable benefits. Such projects are typically needed in order to meet regulatory requirements, comply with software license agreements, replace obsolescent equipment, add infrastructure capacity, or address various business risks. The benefits of these projects are likely to be avoided future costs rather than actual cost reductions.

For projects to enhance business capability, it is expected that there will be financial benefits and that these benefits will either be monetizable or result in avoided costs. Recent examples include the Enterprise Billing Project, discussed in BC Hydro's responses to BCUC IRs 1.114.1 and 1.114.2 and the Supply Chain Applications Project, discussed in the Supply Chain Applications Project Phase Two Verification Report filed with the BCUC on October 12, 2018.

2.126.6 Please confirm that avoided costs need to have deducted from them any related benefits in the forecast scenario.

RESPONSE:

When evaluating technology investments, BC Hydro separates benefits and costs. When comparing investment alternatives, BC Hydro would consider both benefits and costs on a net basis.

Commercial Energy Consumers Association of British Columbia Information Request No. **2.126.7** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

126.0 Reference: Exhibit B-6, CEC 1.61.1

1.61.3 To what extent does BC Hydro typically require its Technology project benefits to be 'monetizable'? Please discuss.

RESPONSE:

BC Hydro requires that all Technology projects identify the benefits that are expected to be realized by the organization. These could include both financial and non-financial benefits.

BC Hydro considers a "monetizable" benefit to be one that can be converted to actual operating or capital cost reductions.

Not all projects are expected to have monetizable benefits. For example, projects categorized as having compliance or risk reduction drivers are unlikely to have monetizable benefits. Such projects are typically needed in order to meet regulatory requirements, comply with software license agreements, replace obsolescent equipment, add infrastructure capacity, or address various business risks. The benefits of these projects are likely to be avoided future costs rather than actual cost reductions.

For projects to enhance business capability, it is expected that there will be financial benefits and that these benefits will either be monetizable or result in avoided costs. Recent examples include the Enterprise Billing Project, discussed in BC Hydro's responses to BCUC IRs 1.114.1 and 1.114.2 and the Supply Chain Applications Project, discussed in the Supply Chain Applications Project Phase Two Verification Report filed with the BCUC on October 12, 2018.

2.126.7 Please confirm that anticipated revenues in any scenario comparison need to have deducted from them any related costs for achieving the revenues.

RESPONSE:

When evaluating technology investments, BC Hydro separates benefits (including increased revenue) and costs. When comparing investment alternatives, BC Hydro would consider both benefits and costs on a net basis.

127.0 Reference: Exhibit B-6, CEC 1.66.1 and 1.66.2 and 1.66.3

66.0 Reference: Exhibit B-1, page 6-150 and 6-151

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

1.66.1 For how long does BC Hydro expect to run its Pilot project?

RESPONSE:

BC Hydro's expects the pilot project to run through fiscal 2020.

1.66.2 What are the metrics that BC Hydro is using to determine whether or not the Pilot is a success or failure?

RESPONSE:

Rather than assess the success or failure of the pilot, BC Hydro will learn from the pilot projects to determine how best to develop the benefits realization process, at the appropriate scale. As part of the learning process, BC Hydro will consider:

- **If BC Hydro able to determine whether the benefits of the projects were achieved, or were on track, as articulated in their respective business cases;**
- **If the effort to track the benefits was acceptable relative to the advantages of tracking the benefits;**
- **If there additional benefits to implementing the pilot such as improving the quality of benefits identification; and**
- **Whether benefits tracking resulted in the development of action plans to protect or increase the realization of benefits.**

1.66.3 If the Pilot is successful does BC Hydro expect to implement it for all its capital projects over a certain dollar threshold or other criteria? Please explain.

RESPONSE:

Yes, BC Hydro intends to implement the benefits realization process for all Technology capital projects based on certain criteria. These criteria will be determined once the pilot is completed.

2.127.1 How and when will the Commission be provided with the results of the Benefits Realization methodology pilot(s)?

RESPONSE:

BC Hydro expects the pilot to run through to the end of fiscal 2020 and accordingly, does not expect to be in a position to provide the BCUC with the results prior to the conclusion of this proceeding. The BCUC and interveners would have the opportunity to request information on the results of the pilot as part of BC Hydro's next Revenue Requirements Application process.

128.0 Reference: Exhibit B-6, CEC 1.67.1 and Exhibit B-1, pages 7-15 – 7-15

67.0 Reference: Exhibit B-1, page 7-14

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]

1.67.1 Please explain what BC Hydro means by 'assuming financial responsibility for controllable risks'. Please explain.

RESPONSE:

Assuming financial responsibility for controllable risks means that ratepayers would not be at risk for any unfavourable variances between actual and forecast amounts in the test period for controllable risks. Rather, any such variances would directly impact BC Hydro's net income and the Government of B.C. as BC Hydro's shareholder. Conversely, the shareholder (and not the ratepayer) would receive the benefit of any favourable variances between actual and forecast amounts for controllable risks.

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.

2.128.1 Please provide some examples of key controllable risks for BC Hydro and the cost values of these risks.

RESPONSE:

Some examples of controllable risks where variances in costs cannot be deferred to a regulatory account and their corresponding cost values which are included in the Evidentiary Update to the Application are as follows:

Item	Appendix A Reference	Fiscal 2020 Cost Value ($ million)
Base Operating costs	**Schedule 5.0, line 9**	**793.8(1)**
Amortization **(DSM and Existing Capital Assets)**	**Schedule 7.0, line 32** **Less items eligible for deferral:** **Schedule 7.0, line 28** **Schedule 7.0, line 30** **Schedule 13.0, line 35**	**1,052.5**
Provisions and other costs	**Schedule 5.0, lines 65 to 71(2)**	**59.2**
Taxes	**Schedule 6.0, line 24**	**249.8**

1. **Note that variances between forecast and actual Storm Restoration Costs and Current Service Costs are eligible for deferral to regulatory accounts under existing BCUC orders.**
2. **Lines 65 to 71 include asset retirements and gains/losses on asset disposals.**

Commercial Energy Consumers Association of British Columbia Information Request No. **2.128.2** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 2
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

128.0 Reference: Exhibit B-6, CEC 1.67.1 and Exhibit B-1, pages 7-15 – 7-15

67.0 Reference: Exhibit B-1, page 7-14

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]

1.67.1 Please explain what BC Hydro means by 'assuming financial responsibility for controllable risks'. Please explain.

RESPONSE:

Assuming financial responsibility for controllable risks means that ratepayers would not be at risk for any unfavourable variances between actual and forecast amounts in the test period for controllable risks. Rather, any such variances would directly impact BC Hydro's net income and the Government of B.C. as BC Hydro's shareholder. Conversely, the shareholder (and not the ratepayer) would receive the benefit of any favourable variances between actual and forecast amounts for controllable risks.

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.

2.128.2 Does BC Hydro typically utilize conservative planning for controllable or other risks? Please discuss.

RESPONSE:

BC Hydro does not typically use conservative planning for costs within BC Hydro's control that cannot be deferred to a regulatory account. These costs are forecast based on the best available estimate, which is refined in each planning cycle.

As shown in BC Hydro's response to CEC IR 2.128.3, in four of the last five fiscal years, BC Hydro's net income has been at or below its approved RRA net income, which is an indicator that BC Hydro has not used conservative planning for its controllable costs.

128.0 Reference: Exhibit B-6, CEC 1.67.1 and Exhibit B-1, pages 7-15 – 7-15

67.0 Reference: Exhibit B-1, page 7-14

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]

1.67.1 Please explain what BC Hydro means by 'assuming financial responsibility for controllable risks'. Please explain.

RESPONSE:

Assuming financial responsibility for controllable risks means that ratepayers would not be at risk for any unfavourable variances between actual and forecast amounts in the test period for controllable risks. Rather, any such variances would directly impact BC Hydro's net income and the Government of B.C. as BC Hydro's shareholder. Conversely, the shareholder (and not the ratepayer) would receive the benefit of any favourable variances between actual and forecast amounts for controllable risks.

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.

2.128.3 Please confirm that examining historical planning and results would permit the Commission and ratepayers to determine if BC Hydro has a conservative planning bias over time.

RESPONSE:

BC Hydro does not consider that examining historical planning and results alone would permit the BCUC and ratepayers to determine if BC Hydro has a conservative planning bias.

Variances to plan can be comprised of a multitude of factors that can vary year-to-year and would need to be examined individually.

As shown in the table below, in four of the last five fiscal years BC Hydro's actual net income has been at or below its approved RRA net income. If BC Hydro had a conservative planning bias in respect to controllable/non-deferrable costs, one would expect to see such bias result in higher than planned actual net income.

Fiscal Year	RRA Approved Net Income ($ million)	Actual Net Income ($ million)	Variance ($ million)
Fiscal 2019*	**712**	**(428)**	**(1,140)**
Fiscal 2018	**698**	**684**	**(14)**
Fiscal 2017	**684**	**684**	**0**
Fiscal 2016	**652**	**655**	**3**
Fiscal 2015	**582**	**581**	**(1)**

***Note – Includes impact of Rate Smoothing Regulatory Account write-off. Excluding this impact, actual net income would have been $4 million lower than plan.**

128.0 Reference: Exhibit B-6, CEC 1.67.1 and Exhibit B-1, pages 7-15 – 7-15

67.0 Reference: Exhibit B-1, page 7-14

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]

1.67.1 Please explain what BC Hydro means by 'assuming financial responsibility for controllable risks'. Please explain.

RESPONSE:

Assuming financial responsibility for controllable risks means that ratepayers would not be at risk for any unfavourable variances between actual and forecast amounts in the test period for controllable risks. Rather, any such variances would directly impact BC Hydro's net income and the Government of B.C. as BC Hydro's shareholder. Conversely, the shareholder (and not the ratepayer) would receive the benefit of any favourable variances between actual and forecast amounts for controllable risks.

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.

2.128.3 Please confirm that examining historical planning and results would permit the Commission and ratepayers to determine if BC Hydro has a conservative planning bias over time.

2.128.3.1 If not confirmed, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.128.3 where we explain why BC Hydro does not consider that examining historical planning and results would, on its own, permit the BCUC and ratepayers to determine if BC Hydro has a conservative planning bias.

128.0 Reference: Exhibit B-6, CEC 1.67.1 and Exhibit B-1, pages 7-15 – 7-15

67.0 Reference: Exhibit B-1, page 7-14

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]

1.67.1 Please explain what BC Hydro means by 'assuming financial responsibility for controllable risks'. Please explain.

RESPONSE:

Assuming financial responsibility for controllable risks means that ratepayers would not be at risk for any unfavourable variances between actual and forecast amounts in the test period for controllable risks. Rather, any such variances would directly impact BC Hydro's net income and the Government of B.C. as BC Hydro's shareholder. Conversely, the shareholder (and not the ratepayer) would receive the benefit of any favourable variances between actual and forecast amounts for controllable risks.

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.

2.128.3 Please confirm that examining historical planning and results would permit the Commission and ratepayers to determine if BC Hydro has a conservative planning bias over time.

2.128.3.2 If not confirmed, please explain how ratepayers and the Commission can determine if the utility is utilizing conservative assumptions in its planning for controllable risks?

RESPONSE:

As part of BC Hydro's revenue requirements applications, BC Hydro provides evidence in an open and transparent manner. This evidence includes details regarding our planning and budgeting methodologies, benchmarking data, historical financial information and explanations for variances between forecast and actual results. In addition, the BCUC and interveners can ask questions on these items to gain further insight into our planned and actual costs. For additional information, please refer to BC Hydro's response to CEC IR 2.128.3.

128.0 Reference: Exhibit B-6, CEC 1.67.1 and Exhibit B-1, pages 7-15 – 7-15

67.0 Reference: Exhibit B-1, page 7-14

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]

1.67.1 Please explain what BC Hydro means by 'assuming financial responsibility for controllable risks'. Please explain.

RESPONSE:

Assuming financial responsibility for controllable risks means that ratepayers would not be at risk for any unfavourable variances between actual and forecast amounts in the test period for controllable risks. Rather, any such variances would directly impact BC Hydro's net income and the Government of B.C. as BC Hydro's shareholder. Conversely, the shareholder (and not the ratepayer) would receive the benefit of any favourable variances between actual and forecast amounts for controllable risks.

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.

2.128.4 Please confirm that conservative planning for controllable risks could result in ratepayers paying for costs that do not materialize but are then provided to the shareholder as a favourable variance between actual and forecast amounts.

RESPONSE:

BC Hydro confirms that, all else equal, if in a given year, it underspends in an area that is not subject to deferral, the variance is to the account of the shareholder.

On an overall basis, this would manifest in higher actual net income (compared to plan).

Please refer to BC Hydro's response to CEC IR 2.128.3, where we show that in four of the last five years, BC Hydro's net income has been at or below its approved RRA net income.

129.0 Reference: Exhibit B-6, CEC 1.78.2 and 1.78.3

1.78.2 Will the long run marginal cost of $105/MWh be reduced in the future as a result of fewer IPP renewals than previously anticipated? Please comment.

RESPONSE:

Having fewer IPP renewals than previously anticipated is not expected to affect the long run marginal cost (LRMC) because the energy LRMC is based on the cost of greenfield IPPs. This is done in order to comply with section 4.1.1 of the Demand-Side Management Regulation which requires that "the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia" be used in the total resource cost test. BC Hydro interprets this LRMC in the Demand-Side Management Regulation to be the cost of acquiring greenfield IPP resources.

The LRMC of $105/MWh is based on an outdated assessment of greenfield wind projects in the Peace River region and the cost to integrate and deliver this energy to the Lower Mainland. BC Hydro plans to update its LRMC in the next IRP.

Application

1.78.3 Does the long run marginal cost take into account the technological improvements anticipated for potential supply and demand side reduction opportunities and if so please provide the data used?

RESPONSE:

The long run marginal cost (LRMC) of energy is based on an outdated cost assessment for greenfield wind projects in the Peace River region and it includes BC Hydro's cost to integrate and deliver the energy to the Lower Mainland load centre. The LRMC is not affected by demand side reduction opportunities.

The wind cost assessment was undertaken in 2014 to 2015 and only took into account technological improvements in a limited way. In particular, BC Hydro's assumptions on wind turbine characteristics were three to five years forward looking at the time.

BC Hydro's assumptions on wind turbine characteristics are documented in this December 2014 presentation to technical stakeholders (found in the link below, slides 10 to 13) as part of BC Hydro's 2015 electricity supply options update work.

https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-characterization-wind-meeting2-20141215-presentation.pdf

2.129.1 Please explain why BC Hydro interprets 'electricity generated from clean or renewable resources in British Columbia' to only include 'greenfield' IPP resources, and not existing IPP resources.

RESPONSE:

In general, the Long Run Marginal Cost (LRMC) can be defined as the price of the most cost-effective way of satisfying incremental customer demand beyond existing and committed resources. With respect to the DSM Regulation, BC Hydro has considered the LRMC to be based on greenfield IPP resources and not existing IPP resources because the existing IPP resources are already serving load and not available to serve new incremental load in the long-term.

BC Hydro will be reviewing the long run marginal cost in the next IRP.

129.0 Reference: Exhibit B-6, CEC 1.78.2 and 1.78.3

1.78.2 Will the long run marginal cost of $105/MWh be reduced in the future as a result of fewer IPP renewals than previously anticipated? Please comment.

RESPONSE:

Having fewer IPP renewals than previously anticipated is not expected to affect the long run marginal cost (LRMC) because the energy LRMC is based on the cost of greenfield IPPs. This is done in order to comply with section 4.1.1 of the Demand-Side Management Regulation which requires that "the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia" be used in the total resource cost test. BC Hydro interprets this LRMC in the Demand-Side Management Regulation to be the cost of acquiring greenfield IPP resources.

The LRMC of $105/MWh is based on an outdated assessment of greenfield wind projects in the Peace River region and the cost to integrate and deliver this energy to the Lower Mainland. BC Hydro plans to update its LRMC in the next IRP.

Application

1.78.3 Does the long run marginal cost take into account the technological improvements anticipated for potential supply and demand side reduction opportunities and if so please provide the data used?

RESPONSE:

The long run marginal cost (LRMC) of energy is based on an outdated cost assessment for greenfield wind projects in the Peace River region and it includes BC Hydro's cost to integrate and deliver the energy to the Lower Mainland load centre. The LRMC is not affected by demand side reduction opportunities.

The wind cost assessment was undertaken in 2014 to 2015 and only took into account technological improvements in a limited way. In particular, BC Hydro's assumptions on wind turbine characteristics were three to five years forward looking at the time.

BC Hydro's assumptions on wind turbine characteristics are documented in this December 2014 presentation to technical stakeholders (found in the link below, slides 10 to 13) as part of BC Hydro's 2015 electricity supply options update work.

https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-characterization-wind-meeting2-20141215-presentation.pdf

2.129.2 How would the long run marginal cost be affected if BC Hydro were to utilize an estimated average cost of existing IPP projects instead of greenfield IPP projects in the calculation? Please quantify to the extent possible.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.129.1 for the reasons why the cost of existing IPPs is not appropriate to use for a long run marginal cost.

129.0 Reference: Exhibit B-6, CEC 1.78.2 and 1.78.3

1.78.2 Will the long run marginal cost of $105/MWh be reduced in the future as a result of fewer IPP renewals than previously anticipated? Please comment.

RESPONSE:

Having fewer IPP renewals than previously anticipated is not expected to affect the long run marginal cost (LRMC) because the energy LRMC is based on the cost of greenfield IPPs. This is done in order to comply with section 4.1.1 of the Demand-Side Management Regulation which requires that "the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia" be used in the total resource cost test. BC Hydro interprets this LRMC in the Demand-Side Management Regulation to be the cost of acquiring greenfield IPP resources.

The LRMC of $105/MWh is based on an outdated assessment of greenfield wind projects in the Peace River region and the cost to integrate and deliver this energy to the Lower Mainland. BC Hydro plans to update its LRMC in the next IRP.

1.78.3 Does the long run marginal cost take into account the technological improvements anticipated for potential supply and demand side reduction opportunities and if so please provide the data used?

RESPONSE:

The long run marginal cost (LRMC) of energy is based on an outdated cost assessment for greenfield wind projects in the Peace River region and it includes BC Hydro's cost to integrate and deliver the energy to the Lower Mainland load centre. The LRMC is not affected by demand side reduction opportunities.

The wind cost assessment was undertaken in 2014 to 2015 and only took into account technological improvements in a limited way. In particular, BC Hydro's assumptions on wind turbine characteristics were three to five years forward looking at the time.

BC Hydro's assumptions on wind turbine characteristics are documented in this December 2014 presentation to technical stakeholders (found in the link below, slides 10 to 13) as part of BC Hydro's 2015 electricity supply options update work.

https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-characterization-wind-meeting2-20141215-presentation.pdf

2.129.3 How would the long run marginal cost be affected if BC Hydro were to utilize a 50/50 mix of greenfield IPP projects and an estimated average cost of existing IPP projects in the calculation? Please quantify to the extent possible.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.129.1 for the reasons why the cost of existing IPPs is not appropriate to use for a long run marginal cost.

130.0 Reference: Exhibit B-6, CEC 1.79.1 and 1.80.1 and 1.80.2

1.79.1 Please explain why the Commercial programming is proposed to decline in value from $18.9 million in F2020 to $17.5 million in F2021 and in energy impact whereas the Residential and Industrial programs are proposed to increase.

RESPONSE:

The main driver for the drop in expenditures from fiscal 2020 to fiscal 2021 is the exit from the market of the Commercial New Construction program. As discussed in the Application, the Commercial New Construction program is winding down to transition to a Codes and Standards strategy that supports the BC Energy Step Code, as outlined on pages 45 to 46 of section 6.3 of Appendix X of the Application. Leaders in Energy Management – Commercial and Commercial Energy Management Activities expenditures have not declined during this period.

The industrial program expenditures increase in fiscal 2021 as a result of the TMP program; however, BC Hydro has updated its TMP forecast as discussed in BC Hydro's response to BCUC IR 1.182.1. Please also refer to BC Hydro's response to AMPC IR 1.5.6 for more information on how BC Hydro determined its portfolio expenditures, including the increase in residential program expenditures, for fiscal 2020 and fiscal 2021.

1.80.1 Please explain why Commercial programming declined from $33 million in F2016 to $24.7 million in F2018.

RESPONSE:

BC Hydro's continuation of the moderation strategy for fiscal 2017 to fiscal 2019, as outlined in the Previous Application, included a planned decline in commercial program spending. As explained in BC Hydro's response to CEC IR 1.111.3 in the Previous Application, reductions to commercial spending were planned to take effect in fiscal 2018 and fiscal 2019. The decline did not occur immediately in fiscal 2017 due to a spike in activity in response to the announced changes to commercial program offers.

Commercial Sector										
Leaders in Energy Management - Commercial	40,191	33,784	29,576	26,394	31,400	25,159	31,348	25,050	20,350	15,221
New Construction	8,393	7,672	8,764	9,011	7,416	7,360	11,549	8,781	8,507	8,901
Sector Enabling Activities	1,238	1,176	1,127	1,245	1,174	1,089	1,000	682	1,020	591
Commercial Sector Total	49,822	42,631	39,467	36,650	39,990	33,609	43,898	34,513	29,877	24,714

2.130.1 What options, if any, does BC Hydro have available to replace the expenditure from the Commercial New Construction program? Please explain.

RESPONSE:

This answer also responds to CEC IR 2.130.2.

The expenditures for the Commercial New Construction program decline over the test period as the program is being phased out as part of the moderation strategy outlined in the Previous Application. BC Hydro is supporting the transformation of the commercial new construction market through codes and standards activities. The DSM Plan in the Application includes expenditures to support commercial new construction step code development and industry education and capacity building.

As the reduced expenditures were part of the planned moderation strategy, BC Hydro has not explored other program options to replace the Commercial New Construction expenditures going forward.

130.0 Reference: Exhibit B-6, CEC 1.79.1 and 1.80.1 and 1.80.2

1.79.1 Please explain why the Commercial programming is proposed to decline in value from $18.9 million in F2020 to $17.5 million in F2021 and in energy impact whereas the Residential and Industrial programs are proposed to increase.

RESPONSE:

The main driver for the drop in expenditures from fiscal 2020 to fiscal 2021 is the exit from the market of the Commercial New Construction program. As discussed in the Application, the Commercial New Construction program is winding down to transition to a Codes and Standards strategy that supports the BC Energy Step Code, as outlined on pages 45 to 46 of section 6.3 of Appendix X of the Application. Leaders in Energy Management – Commercial and Commercial Energy Management Activities expenditures have not declined during this period.

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1.80.1 Please explain why Commercial programming declined from $33 million in F2016 to $24.7 million in F2018.

RESPONSE:

BC Hydro's continuation of the moderation strategy for fiscal 2017 to fiscal 2019, as outlined in the Previous Application, included a planned decline in commercial program spending. As explained in BC Hydro's response to CEC IR 1.111.3 in the Previous Application, reductions to commercial spending were planned to take effect in fiscal 2018 and fiscal 2019. The decline did not occur immediately in fiscal 2017 due to a spike in activity in response to the announced changes to commercial program offers.

Commercial Sector										
Leaders in Energy Management - Commercial	40,191	33,784	29,576	26,394	31,400	25,159	31,348	25,050	20,350	15,221
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Sector Enabling Activities	1,238	1,176	1,127	1,245	1,174	1,089	1,000	682	1,020	591
Commercial Sector Total	49,822	42,631	39,467	36,650	39,990	33,609	43,898	34,513	29,877	24,714

2.130.2 Please comment on whether or not BC Hydro considered replacing the expenditures with these options and, if not, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.130.1, where we explain why BC Hydro did not consider replacing expenditures related to the Commercial New Construction program.

30.0 Reference: Exhibit B-6, CEC 1.79.1 and 1.80.1 and 1.80.2

1.79.1 Please explain why the Commercial programming is proposed to decline in value from $18.9 million in F2020 to $17.5 million in F2021 and in energy impact whereas the Residential and Industrial programs are proposed to increase.

RESPONSE:

The main driver for the drop in expenditures from fiscal 2020 to fiscal 2021 is the exit from the market of the Commercial New Construction program. As discussed in the Application, the Commercial New Construction program is winding down to transition to a Codes and Standards strategy that supports the BC Energy Step Code, as outlined on pages 45 to 46 of section 6.3 of Appendix X of the Application. Leaders in Energy Management – Commercial and Commercial Energy Management Activities expenditures have not declined during this period.

The industrial program expenditures increase in fiscal 2021 as a result of the TMP program; however, BC Hydro has updated its TMP forecast as discussed in BC Hydro's response to BCUC IR 1.182.1. Please also refer to BC Hydro's response to AMPC IR 1.5.6 for more information on how BC Hydro determined its portfolio expenditures, including the increase in residential program expenditures, for fiscal 2020 and fiscal 2021.

1.80.1 Please explain why Commercial programming declined from $33 million in F2016 to $24.7 million in F2018.

RESPONSE:

BC Hydro's continuation of the moderation strategy for fiscal 2017 to fiscal 2019, as outlined in the Previous Application, included a planned decline in commercial program spending. As explained in BC Hydro's response to CEC IR 1.111.3 in the Previous Application, reductions to commercial spending were planned to take effect in fiscal 2018 and fiscal 2019. The decline did not occur immediately in fiscal 2017 due to a spike in activity in response to the announced changes to commercial program offers.

Commercial Sector										
Leaders in Energy Management - Commercial	40,191	33,784	29,576	26,394	31,400	25,159	31,348	25,050	20,350	15,221
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Sector Enabling Activities	1,238	1,176	1,127	1,245	1,174	1,089	1,000	682	1,020	591
Commercial Sector Total	49,822	42,631	39,467	36,650	39,990	33,609	43,898	34,513	29,877	24,714

2.130.3 BC Hydro's commercial programming expenditures decline from planned spending of $49 million in F2019 to $17.5 million in F2021. Does BC Hydro expect to continue to reduce commercial programming in the period following F2021? Please comment and quantify to the extent that BC Hydro has future forecasts available at this time.

RESPONSE:

BC Hydro does not expect to reduce commercial programming beyond what is reflected for Commercial New Construction in the Application.

Based on BC Hydro's current outlook, excluding Commercial New Construction, our commercial expenditures are expected to remain relatively flat through fiscal 2030 with minor variations in given years. We expect an average annual spend over the time period fiscal 2022 to fiscal 2030 that is within 1 per cent of the fiscal 2021 expenditures.

131.0 Reference: Exhibit B-6, CEC 1.81.1

> 1.81.1 Please explain why BC Hydro did not spend its Leaders in Energy Management – commercial planned expenditures in Fiscal 2018.
>
> **RESPONSE:**
>
> **Expenditures for Leaders in Energy Management – Commercial were below plan due to customers requiring lower incentive levels, decreases in project technology costs, and customer decisions to delay or cancel projects.**

2.131.1 Please explain the statement 'customers requiring lower incentive levels'.

RESPONSE:

The statement "customers requiring lower incentive levels" means that the mix of projects that customers submitted under the Leaders in Energy Management program had lower costs, and therefore lower incentive levels, associated with the implementation of the energy efficiency measures than was originally planned.

131.0 Reference: Exhibit B-6, CEC 1.81.1

1.81.1 Please explain why BC Hydro did not spend its Leaders in Energy Management – commercial planned expenditures in Fiscal 2018.

RESPONSE:

Expenditures for Leaders in Energy Management – Commercial were below plan due to customers requiring lower incentive levels, decreases in project technology costs, and customer decisions to delay or cancel projects.

2.131.2 Will BC Hydro continue to make Leaders in Energy Management available for customers whose projects were delayed? Please explain.

RESPONSE:

Yes. For customers who delayed their projects, BC Hydro will provide incentives in the amounts stated in the demand-side management incentive agreement, once the project is successfully implemented.

132.0 Reference: Exhibit B-6, CEC 1.88.1

88.0 Reference: Exhibit B-1, Appendix C, page 23

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.

1.88.1 When does BC Hydro expect the second phase of the Review to be implemented and completed?

RESPONSE:

Phase Two of the Comprehensive Review is expected to begin in spring 2019 following the Government of B.C.'s release of the review's terms of reference.

Phase Two of the Comprehensive Review will be informed by government's CleanBC plan and focused on ensuring that BC Hydro is well positioned to maximize opportunities flowing from shifts taking place in the global and regional energy sectors, technological change and climate action.

The timing of implementation will depend on the recommendations and the timing of the completion of the review.

2.132.1 Please provide the current status of the second phase of the Review.

RESPONSE:

On July 19, 2019, the Government of B.C. released the Terms of Reference for Phase 2 of the Comprehensive Review. The document can also be found at the following link:

https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bch_review_phase_ii_tor_190716_public_clean.pdf

The following teams are working together on this phase to produce recommendations that will position BC Hydro for long-term success:

- **The Ministry of Energy, Mines and Petroleum Resources;**
- **BC Hydro;**

- **Energy industry experts with extensive experience in North American utility operation, technology, regulation and electricity markets; and**
- **The Ministry of Environment and Climate Change Strategy.**

A final report with recommendations is expected to be completed in early 2020.

132.0 Reference: Exhibit B-6, CEC 1.88.1

88.0 Reference: Exhibit B-1, Appendix C, page 23

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.

1.88.1 When does BC Hydro expect the second phase of the Review to be implemented and completed?

RESPONSE:

Phase Two of the Comprehensive Review is expected to begin in spring 2019 following the Government of B.C.'s release of the review's terms of reference.

Phase Two of the Comprehensive Review will be informed by government's CleanBC plan and focused on ensuring that BC Hydro is well positioned to maximize opportunities flowing from shifts taking place in the global and regional energy sectors, technological change and climate action.

The timing of implementation will depend on the recommendations and the timing of the completion of the review.

2.132.2 Please provide any key objectives that have been developed as part of the second phase.

RESPONSE:

As set out in the Terms of Reference (please refer to BC Hydro's response to CEC IR 2.132.1 for a link to the Terms of Reference) the objective of the second phase of the Comprehensive Review is to develop recommendations for how BC Hydro can accomplish the provincial policy objectives laid out in the CleanBC plan, including how BC Hydro can support meeting British Columbia's legislated 2030, 2040, and 2050 greenhouse gas reduction targets in a manner that ensures BC Hydro's sustainability in the future for the benefit of British Columbians.

The review will consider the potential impacts of North American energy and market trends, the needs of current and future BC Hydro customers, evolving technologies and utility structures, the affordability of electricity to consumers, and opportunities to involve indigenous peoples and communities.

133.0 Reference: Exhibit B-6, CEC 1.90.1

90.0 Reference: Exhibit B-1, Appendix C, page 33

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.

1.90.1 When does BC Hydro expect to implement a freshet rate for commercial customers?

RESPONSE:

BC Hydro does not currently have any plans to implement a freshet energy rate for commercial customers.

2.133.1 Please elaborate on why BC Hydro does not have any plans to implement a freshet rate for commercial customers.

RESPONSE:

This answer also responds to CEC IRs 2.133.2 and 2.133.2.1.

BC Hydro has not recently been approached by any individual commercial customers requesting a freshet rate, although the topic was raised in BC Hydro's 2015 Rate Design Application. If there was sufficient customer interest, BC Hydro would examine a freshet rate for commercial customers.

133.0 Reference: Exhibit B-6, CEC 1.90.1

90.0 Reference: Exhibit B-1, Appendix C, page 33

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.

1.90.1 When does BC Hydro expect to implement a freshet rate for commercial customers?

RESPONSE:

BC Hydro does not currently have any plans to implement a freshet energy rate for commercial customers.

2.133.2 Has BC Hydro considered developing a pilot for a commercial freshet rate?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 2.133.1.

133.0 Reference: Exhibit B-6, CEC 1.90.1

90.0 Reference: Exhibit B-1, Appendix C, page 33

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.

1.90.1 When does BC Hydro expect to implement a freshet rate for commercial customers?

RESPONSE:

BC Hydro does not currently have any plans to implement a freshet energy rate for commercial customers.

2.133.2 Has BC Hydro considered developing a pilot for a commercial freshet rate?

2.133.2.1 If not, please explain why not.

RESPONSE:

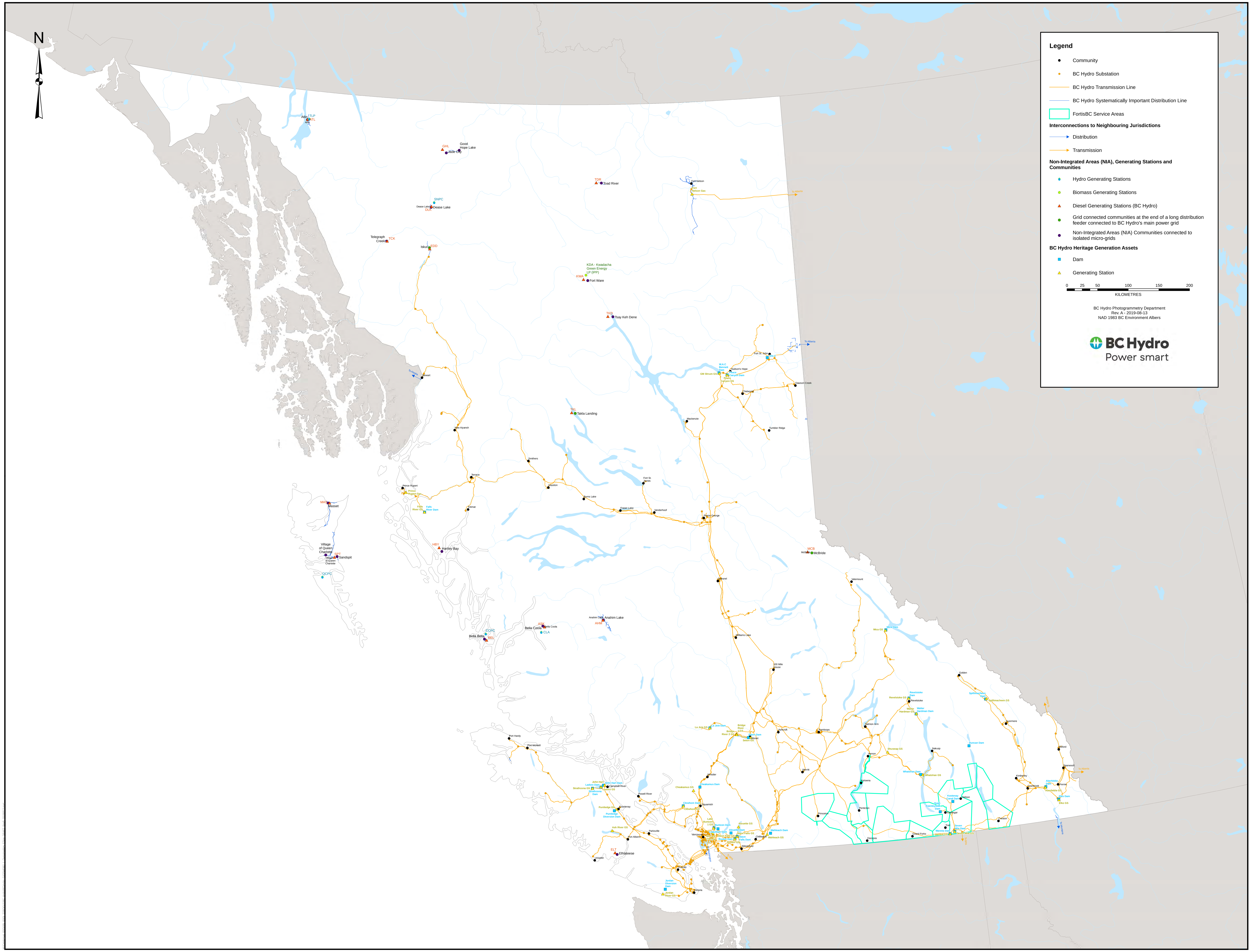
Please refer to BC Hydro's response to CEC IR 2.133.1

1.0 Reference: Gjoshe IR 1.1.1

2.1 Please provide the map requested in Gjoshe IR 1.1.1. If GIS-based mapping is unsuitable due to the amount of detail, please provide an illustrative map (while preserving geographical accuracy) that includes a visual representation of all of the requested data. For the distribution system, only include systemically important elements (example: regionally important radial lines serving those regions not served at transmission voltage, or the distribution system of regional or non-integrated areas if deemed systemically important, etc.). Please include transmission and distribution system (where included) voltage. For purposes of this map, please ignore boundary delineations with the New Westminster service area.

RESPONSE:

Please refer to the map, provided as Attachment 1 to this response. The attached map contains layers that can be independently switched off and on by the reader, to allow the reader to view all of the information at one time, or select some of the information to make the map more readable.


Legend
Community
BC Hydro Substation
BC Hydro Transmission Line
BC Hydro Systematically Important Distribution Line
FortisBC Service Areas
Interconnections to Neighbouring Jurisdictions
Distribution
Transmission
Non-Integrated Areas (NIA), Generating Stations and Communities
Hydro Generating Stations
Biomass Generating Stations
Diesel Generating Stations (BC Hydro)
Grid connected communities at the end of a long distribution feeder connected to BC Hydro's main power grid
Non-Integrated Areas (NIA) Communities connected to isolated micro-grids
BC Hydro Heritage Generation Assets
Dam
Generating Station
0 25 50 100 150 200
KILOMETRES
BC Hydro Photogrammetry Department
Rev. A - 2019-08-13
NAD 1983 BC Environment Albers
BC Hydro
Power smart
N

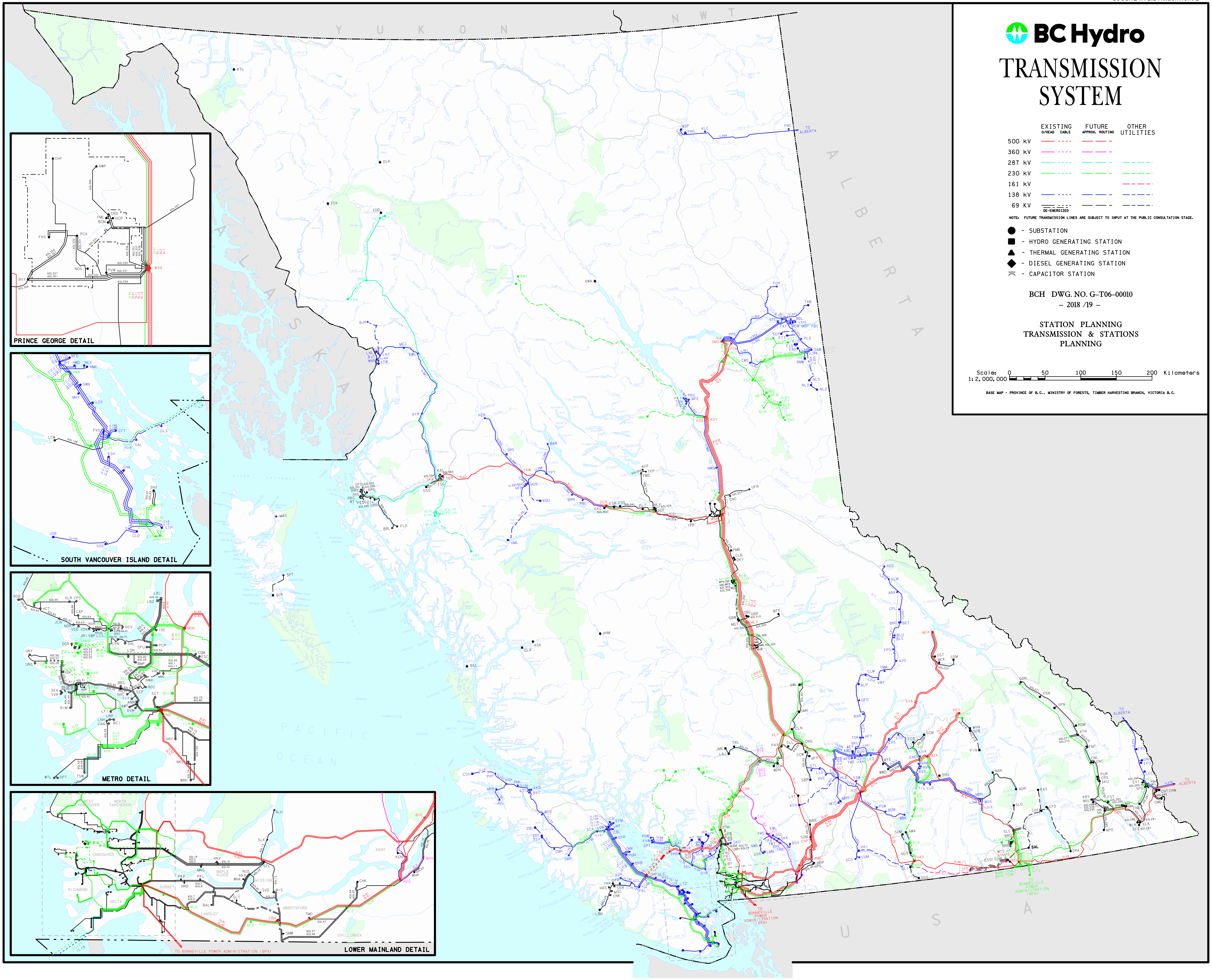
2.0 Reference: Gjoshe IR 1.1.2

2.2 As per Gjoshe IR 1.1.2, please provide a map of the four service regions (Lower Mainland, Vancouver Island, South Interior and the North Region) used in the SAE modelling, overlaying the boundaries of the four service regions to the base BC Hydro system map.

RESPONSE:

The four service regions which are used in BC Hydro's SAE modelling are delineated by the substations providing service to the regions, not by boundaries on a map.

To show the location of the substations, a map of BC Hydro's transmission system and a list of the substations in each of the four service areas (and in the Non-Integrated Areas) are provided as Attachments 1 and 2 respectively to this response.


BC Hydro
TRANSMISSION SYSTEM
EXISTING O/HEAD CABLE
FUTURE APPROX. ROUTING
OTHER UTILITIES
500 kV
360 kV
287 kV
230 kV
161 kV
138 kV
69 kV
DE-ENERGIZED
NOTE: FUTURE TRANSMISSION LINES ARE SUBJECT TO INPUT AT THE PUBLIC CONSULTATION STAGE.
- SUBSTATION
- HYDRO GENERATING STATION
- THERMAL GENERATING STATION
- DIESEL GENERATING STATION
- CAPACITOR STATION
BCH DWG. NO. G–T06–00010
– 2018 /19 –
STATION PLANNING
TRANSMISSION & STATIONS PLANNING
Scale: 1: 2,000,000
0 50 100 150 200 Kilometers
BASE MAP - PROVINCE OF B.C., MINISTRY OF FORESTS, TIMBER HARVESTING BRANCH, VICTORIA B.C.
PRINCE GEORGE DETAIL
SOUTH VANCOUVER ISLAND DETAIL
METRO DETAIL
LOWER MAINLAND DETAIL
Y U K O N
N W T
A L B E R T A
A L A S K A
P A C I F I C
O C E A N
U S A
TO ALBERTA
TO BONNEVILLE POWER ADMINISTRATION (BPA)

List of Stations and Regions

(Note: BC Hydro does not designate sub-regions for transmission substations).

Substation Type	Three Letter Code	REGION	SUB-REGION
Distribution	ALZ	LM - Lower Mainland	FV EAST
Distribution	BBR	LM - Lower Mainland	FV EAST
Distribution	CBN	LM - Lower Mainland	FV EAST
Distribution	CHK	LM - Lower Mainland	FV EAST
Distribution	GLT	LM - Lower Mainland	FV EAST
Distribution	HOP	LM - Lower Mainland	FV EAST
Distribution	KEN	LM - Lower Mainland	FV EAST
Distribution	MIS	LM - Lower Mainland	FV EAST
Distribution	MLE	LM - Lower Mainland	FV EAST
Distribution	SMW	LM - Lower Mainland	FV EAST
Distribution	SVD	LM - Lower Mainland	FV EAST
Distribution	SZM	LM - Lower Mainland	FV EAST
Distribution	WAH	LM - Lower Mainland	FV EAST
Distribution	CAM	LM - Lower Mainland	FV RICHMOND
Distribution	KI2	LM - Lower Mainland	FV RICHMOND
Distribution	RIM	LM - Lower Mainland	FV RICHMOND
Distribution	SEA	LM - Lower Mainland	FV RICHMOND
Distribution	STV	LM - Lower Mainland	FV RICHMOND
Distribution	ANN	LM - Lower Mainland	FV WEST
Distribution	ARN	LM - Lower Mainland	FV WEST
Distribution	BAL	LM - Lower Mainland	FV WEST
Distribution	CDL	LM - Lower Mainland	FV WEST
Distribution	FLW	LM - Lower Mainland	FV WEST
Distribution	HRD	LM - Lower Mainland	FV WEST
Distribution	MLN	LM - Lower Mainland	FV WEST
Distribution	NKL	LM - Lower Mainland	FV WEST
Distribution	PKL	LM - Lower Mainland	FV WEST
Distribution	SCT	LM - Lower Mainland	FV WEST
Distribution	SRY	LM - Lower Mainland	FV WEST
Distribution	SYH	LM - Lower Mainland	FV WEST
Distribution	TSW	LM - Lower Mainland	FV WEST
Distribution	WHY	LM - Lower Mainland	FV WEST
Distribution	WRK	LM - Lower Mainland	FV WEST
Distribution	BTA	LM - Lower Mainland	METRO COASTAL
Distribution	CKY	LM - Lower Mainland	METRO COASTAL
Distribution	CMS	LM - Lower Mainland	METRO COASTAL
Distribution	COM	LM - Lower Mainland	METRO COASTAL
Distribution	FCN	LM - Lower Mainland	METRO COASTAL
Distribution	FRC	LM - Lower Mainland	METRO COASTAL
Distribution	FVW	LM - Lower Mainland	METRO COASTAL

Substation Type	Three Letter Code	REGION	SUB-REGION
Distribution	GIB	LM - Lower Mainland	METRO COASTAL
Distribution	GPT	LM - Lower Mainland	METRO COASTAL
Distribution	PEM	LM - Lower Mainland	METRO COASTAL
Distribution	PHR	LM - Lower Mainland	METRO COASTAL
Distribution	PTO	LM - Lower Mainland	METRO COASTAL
Distribution	RBW	LM - Lower Mainland	METRO COASTAL
Distribution	SAC	LM - Lower Mainland	METRO COASTAL
Distribution	SEC	LM - Lower Mainland	METRO COASTAL
Distribution	SQH	LM - Lower Mainland	METRO COASTAL
Distribution	UHT	LM - Lower Mainland	METRO COASTAL
Distribution	COK	LM - Lower Mainland	METRO COQUITLAM MAPLERIDGE
Distribution	CQM	LM - Lower Mainland	METRO COQUITLAM MAPLERIDGE
Distribution	HNY	LM - Lower Mainland	METRO COQUITLAM MAPLERIDGE
Distribution	LB1	LM - Lower Mainland	METRO COQUITLAM MAPLERIDGE
Distribution	MRG	LM - Lower Mainland	METRO COQUITLAM MAPLERIDGE
Distribution	CAP	LM - Lower Mainland	METRO NORTHSHORE
Distribution	DCV	LM - Lower Mainland	METRO NORTHSHORE
Distribution	GLR	LM - Lower Mainland	METRO NORTHSHORE
Distribution	HCT	LM - Lower Mainland	METRO NORTHSHORE
Distribution	HSB	LM - Lower Mainland	METRO NORTHSHORE
Distribution	JLN	LM - Lower Mainland	METRO NORTHSHORE
Distribution	LBY	LM - Lower Mainland	METRO NORTHSHORE
Distribution	LYN	LM - Lower Mainland	METRO NORTHSHORE
Distribution	NOR	LM - Lower Mainland	METRO NORTHSHORE
Distribution	NVR	LM - Lower Mainland	METRO NORTHSHORE
Distribution	BBS	LM - Lower Mainland	METRO VANCOUVER BURNABY
Distribution	BND	LM - Lower Mainland	METRO VANCOUVER BURNABY
Distribution	CSN	LM - Lower Mainland	METRO VANCOUVER BURNABY
Distribution	CSQ	LM - Lower Mainland	METRO VANCOUVER BURNABY
Distribution	DGR	LM - Lower Mainland	METRO VANCOUVER BURNABY
Distribution	GDK	LM - Lower Mainland	METRO VANCOUVER BURNABY
Distribution	HPN	LM - Lower Mainland	METRO VANCOUVER BURNABY
Distribution	KI1	LM - Lower Mainland	METRO VANCOUVER BURNABY
Distribution	LOH	LM - Lower Mainland	METRO VANCOUVER BURNABY
Distribution	MAN	LM - Lower Mainland	METRO VANCOUVER BURNABY
Distribution	MPT	LM - Lower Mainland	METRO VANCOUVER BURNABY
Distribution	MUR	LM - Lower Mainland	METRO VANCOUVER BURNABY
Distribution	NEL	LM - Lower Mainland	METRO VANCOUVER BURNABY
Distribution	SPG	LM - Lower Mainland	METRO VANCOUVER BURNABY
Transmission	AWT	LM - Lower Mainland	
Transmission	BCI	LM - Lower Mainland	

Substation Type	Three Letter Code	REGION	SUB-REGION
Transmission	CAN	LM - Lower Mainland	
Transmission	CPS	LM - Lower Mainland	
Transmission	CVN	LM - Lower Mainland	
Transmission	DPT	LM - Lower Mainland	
Transmission	DVM	LM - Lower Mainland	
Transmission	ERW	LM - Lower Mainland	
Transmission	GSP	LM - Lower Mainland	
Transmission	HPS	LM - Lower Mainland	
Transmission	HSP	LM - Lower Mainland	
Transmission	IOC	LM - Lower Mainland	
Transmission	JRI	LM - Lower Mainland	
Transmission	LCS	LM - Lower Mainland	
Transmission	LF1	LM - Lower Mainland	
Transmission	LNH	LM - Lower Mainland	
Transmission	NRG	LM - Lower Mainland	
Transmission	NXC	LM - Lower Mainland	
Transmission	PCP	LM - Lower Mainland	
Transmission	PKP	LM - Lower Mainland	
Transmission	POW	LM - Lower Mainland	
Transmission	RSR	LM - Lower Mainland	
Transmission	SCP	LM - Lower Mainland	
Transmission	SFU	LM - Lower Mainland	
Transmission	SHL	LM - Lower Mainland	
Transmission	SWP	LM - Lower Mainland	
Transmission	TII	LM - Lower Mainland	
Transmission	TMO	LM - Lower Mainland	
Transmission	UNS	LM - Lower Mainland	
Transmission	VDK	LM - Lower Mainland	
Transmission	VSD	LM - Lower Mainland	
Transmission	WCF	LM - Lower Mainland	
Transmission	WHP	LM - Lower Mainland	
Transmission	WTL	LM - Lower Mainland	
Transmission	YVR	LM - Lower Mainland	
Distribution	BVY	North	NORTH CENTRAL
Distribution	CHF	North	NORTH CENTRAL
Distribution	CLB	North	NORTH CENTRAL
Distribution	FHS	North	NORTH CENTRAL
Distribution	GVL	North	NORTH CENTRAL
Distribution	IPR	North	NORTH CENTRAL
Distribution	KDS	North	NORTH CENTRAL
Distribution	MFE	North	NORTH CENTRAL

Substation Type	Three Letter Code	REGION	SUB-REGION
Distribution	MGT	North	NORTH CENTRAL
Distribution	MWN	North	NORTH CENTRAL
Distribution	PCA	North	NORTH CENTRAL
Distribution	PGG	North	NORTH CENTRAL
Distribution	PVW	North	NORTH CENTRAL
Distribution	QNL	North	NORTH CENTRAL
Distribution	RBF	North	NORTH CENTRAL
Distribution	UFR	North	NORTH CENTRAL
Distribution	WLM	North	NORTH CENTRAL
Distribution	CWD	North	NORTH EAST
Distribution	DAW	North	NORTH EAST
Distribution	FJN	North	NORTH EAST
Distribution	FOX	North	NORTH EAST
Distribution	PPS	North	NORTH EAST
Distribution	TLR	North	NORTH EAST
Distribution	TXB	North	NORTH EAST
Distribution	AYH	North	NORTH WEST
Distribution	BAB	North	NORTH WEST
Distribution	BRN	North	NORTH WEST
Distribution	DIL	North	NORTH WEST
Distribution	FM2	North	NORTH WEST
Distribution	FSR	North	NORTH WEST
Distribution	GRR	North	NORTH WEST
Distribution	HUS	North	NORTH WEST
Distribution	HZN	North	NORTH WEST
Distribution	KAL	North	NORTH WEST
Distribution	MEZ	North	NORTH WEST
Distribution	MIN	North	NORTH WEST
Distribution	OFD	North	NORTH WEST
Distribution	PED	North	NORTH WEST
Distribution	SRS	North	NORTH WEST
Distribution	STW	North	NORTH WEST
Distribution	TAT	North	NORTH WEST
Distribution	TER	North	NORTH WEST
Distribution	VDF	North	NORTH WEST
Distribution	AHM	North	North-NIA
Distribution	ASK	North	North-NIA
Distribution	ATL	North	North-NIA
Distribution	BEL	North	North-NIA
Distribution	DLK	North	North-NIA
Distribution	GHL	North	North-NIA

Substation Type	Three Letter Code	REGION	SUB-REGION
Distribution	HBY	North	North-NIA
Distribution	KWA	North	North-NIA
Distribution	MAS	North	North-NIA
Distribution	SPT	North	North-NIA
Distribution	TCK	North	North-NIA
Distribution	TDR	North	North-NIA
Distribution	TKD	North	North-NIA
Transmission	AFP	North	
Transmission	BCM	North	
Transmission	BLM	North	
Transmission	CBP	North	
Transmission	DKY	North	
Transmission	EKO	North	
Transmission	EQU	North	
Transmission	EUR	North	
Transmission	FBC	North	
Transmission	FCC	North	
Transmission	FFI	North	
Transmission	FMC	North	
Transmission	FNC	North	
Transmission	FSS	North	
Transmission	GBR	North	
Transmission	HML	North	
Transmission	HSK	North	
Transmission	KGP	North	
Transmission	KLC	North	
Transmission	KMI	North	
Transmission	LAP	North	
Transmission	LGW	North	
Transmission	MGP	North	
Transmission	MML	North	
Transmission	MNK	North	
Transmission	MTP	North	
Transmission	NGL	North	
Transmission	NHS	North	
Transmission	NL2	North	
Transmission	NL3	North	
Transmission	NL5	North	
Transmission	NLV	North	
Transmission	NOS	North	
Transmission	PBL	North	

Substation Type	Three Letter Code	REGION	SUB-REGION
Transmission	PGP	North	
Transmission	PLT	North	
Transmission	PMB	North	
Transmission	PRG	North	
Transmission	PRT	North	
Transmission	QNT	North	
Transmission	QRP	North	
Transmission	RAY	North	
Transmission	RDC	North	
Transmission	RTI	North	
Transmission	SEP	North	
Transmission	SKL	North	
Transmission	SLO	North	
Transmission	SLO	North	
Transmission	SSQ	North	
Transmission	TBN	North	
Transmission	TCS	North	
Transmission	TFP	North	
Transmission	TWT	North	
Transmission	TXB	North	
Transmission	WFQ	North	
Transmission	WPN	North	
Transmission	WQL	North	
Transmission	WWL	North	
Transmission	WWQ	North	
Distribution	ARM	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	ATH	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	CNL	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	CRO	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	DUC	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	EFD	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	FMT	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	FNE	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	FST	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	GDN	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	INV	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	JOE	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	KAS	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	KGG	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	LU2	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	MON	SI - South Interior	SI OKANAGAN KOOTENAY

Substation Type	Three Letter Code	REGION	SUB-REGION
Distribution	MVL	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	MYE	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	NAK	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	NDR	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	NGT	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	PSN	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	RDM	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	SKU	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	SPD	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	SPL	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	SPN	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	VNT	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	WAR	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	WBK	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	WDS	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	WIN	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	WWD	SI - South Interior	SI OKANAGAN KOOTENAY
Distribution	AFT	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	AVO	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	BAR	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	BKL	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	BLU	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	BR1	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	CHS	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	CLN	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	CLW	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	DUG	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	END	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	HFY	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	HLD	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	HMH	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	ILL	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	LAJ	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	MCA	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	MCK	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	MR2	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	MTE	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	PAV	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	SAM	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	SBR	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	SCM	SI - South Interior	SI THOMPSON SHUSWAP

Substation Type	Three Letter Code	REGION	SUB-REGION
Distribution	SMH	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	SON	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	STO	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	SVA	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	TXL	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	VBY	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	VLM	SI - South Interior	SI THOMPSON SHUSWAP
Distribution	WKA	SI - South Interior	SI THOMPSON SHUSWAP
Transmission	ABA	SI - South Interior	
Transmission	AFN	SI - South Interior	
Transmission	AWL	SI - South Interior	
Transmission	BDM	SI - South Interior	
Transmission	BLE	SI - South Interior	
Transmission	BLP	SI - South Interior	
Transmission	BRM	SI - South Interior	
Transmission	CFE	SI - South Interior	
Transmission	CLL	SI - South Interior	
Transmission	CMO	SI - South Interior	
Transmission	CNT	SI - South Interior	
Transmission	CPL	SI - South Interior	
Transmission	CRC	SI - South Interior	
Transmission	CRS	SI - South Interior	
Transmission	CUM	SI - South Interior	
Transmission	DFD	SI - South Interior	
Transmission	EV1	SI - South Interior	
Transmission	FCO	SI - South Interior	
Transmission	FPS	SI - South Interior	
Transmission	FRO	SI - South Interior	
Transmission	GRH	SI - South Interior	
Transmission	GSM	SI - South Interior	
Transmission	GTL	SI - South Interior	
Transmission	HVC	SI - South Interior	
Transmission	KSD	SI - South Interior	
Transmission	LCC	SI - South Interior	
Transmission	LF2	SI - South Interior	
Transmission	REG	SI - South Interior	
Transmission	SCO	SI - South Interior	
Transmission	STM	SI - South Interior	
Transmission	TIL	SI - South Interior	
Transmission	TMM	SI - South Interior	
Transmission	TMT	SI - South Interior	

Substation Type	Three Letter Code	REGION	SUB-REGION
Transmission	TOK	SI - South Interior	
Transmission	WAN	SI - South Interior	
Transmission	WEY	SI - South Interior	
Distribution	ELT	VI - Vancouver Island	VI - NIA
Distribution	GLS	VI - Vancouver Island	VI CENTRAL
Distribution	HWD	VI - Vancouver Island	VI CENTRAL
Distribution	KSH	VI - Vancouver Island	VI CENTRAL
Distribution	LBH	VI - Vancouver Island	VI CENTRAL
Distribution	LCW	VI - Vancouver Island	VI CENTRAL
Distribution	LDY	VI - Vancouver Island	VI CENTRAL
Distribution	LTZ	VI - Vancouver Island	VI CENTRAL
Distribution	NFD	VI - Vancouver Island	VI CENTRAL
Distribution	PAL	VI - Vancouver Island	VI CENTRAL
Distribution	PVL	VI - Vancouver Island	VI CENTRAL
Distribution	PVO	VI - Vancouver Island	VI CENTRAL
Distribution	QLC	VI - Vancouver Island	VI CENTRAL
Distribution	SAL	VI - Vancouver Island	VI CENTRAL
Distribution	SHA	VI - Vancouver Island	VI CENTRAL
Distribution	SWN	VI - Vancouver Island	VI CENTRAL
Distribution	BKB	VI - Vancouver Island	VI NORTH
Distribution	CBL	VI - Vancouver Island	VI NORTH
Distribution	CMX	VI - Vancouver Island	VI NORTH
Distribution	GLD	VI - Vancouver Island	VI NORTH
Distribution	JUL	VI - Vancouver Island	VI NORTH
Distribution	KGH	VI - Vancouver Island	VI NORTH
Distribution	OYR	VI - Vancouver Island	VI NORTH
Distribution	PHY	VI - Vancouver Island	VI NORTH
Distribution	PML	VI - Vancouver Island	VI NORTH
Distribution	PUN	VI - Vancouver Island	VI NORTH
Distribution	TSV	VI - Vancouver Island	VI NORTH
Distribution	WOS	VI - Vancouver Island	VI NORTH
Distribution	CLD	VI - Vancouver Island	VI SOUTH
Distribution	ESQ	VI - Vancouver Island	VI SOUTH
Distribution	GOW	VI - Vancouver Island	VI SOUTH
Distribution	GTP	VI - Vancouver Island	VI SOUTH
Distribution	HSY	VI - Vancouver Island	VI SOUTH
Distribution	JOR	VI - Vancouver Island	VI SOUTH
Distribution	KTG	VI - Vancouver Island	VI SOUTH
Distribution	SNY	VI - Vancouver Island	VI SOUTH
Distribution	SOO	VI - Vancouver Island	VI SOUTH
Transmission	BVC	VI - Vancouver Island	

Substation Type	Three Letter Code	REGION	SUB-REGION
Transmission	CFT	VI - Vancouver Island	
Transmission	DND	VI - Vancouver Island	
Transmission	EFM	VI - Vancouver Island	
Transmission	GRP	VI - Vancouver Island	
Transmission	HMC	VI - Vancouver Island	
Transmission	ICG	VI - Vancouver Island	
Transmission	JUL	VI - Vancouver Island	
Transmission	MHY	VI - Vancouver Island	
Transmission	NEX	VI - Vancouver Island	
Transmission	PAL	VI - Vancouver Island	

3.0 Reference: Gjoshe IR 1.1.3

2.3 As per Gjoshe IR 1.1.3, please provide a map of the 15 sub-regions used in the SAE modelling, overlaying the boundaries of the 15 sub-regions to the base BC Hydro system map (for each sub-region, please use the outer boundary delineations of the collective District Boundaries as provided in the maps in response to Gjoshe IR 1.1.4).

RESPONSE:

To clarify, BC Hydro does not develop SAE models for the 15 sub-regions. SAE models are done at the four region level.

Please refer to BC Hydro's response to GJOSHE IR 2.2 which explains that the regions and sub-regions are not delineated by boundaries on a map. However, the approximate delineation of the sub-regions can be found by referencing a map of BC Hydro's transmission system and a list of substations, which are provided as attachments to BC Hydro's response to GJOSHE IR 2.2.

4.0 References: Gjoshe IR 1.1.4 and Gjoshe IR 1.1.5

2.4 In response to Gjoshe IR 1.1.4 BC Hydro states: ‘To clarify, the regional breakdown of BC Hydro's SAE models is to each of the four regions, and not for each of the 15 sub-regions. BC Hydro develops an account forecast for each of the 15 sub-regions, which is aggregated for use in the four SAE regional models."
In response to Gjoshe IR 1.1.5 BC Hydro states: ‘To clarify, the residential and commercial SAE sales forecasts are not developed at the sub-region level. The 15 sub-regions are used to determine the forecast number of residential accounts and use per account which are then aggregated into the four regional SAE models.'

2.4.1 Please clarify whether the account forecast that BC Hydro develops for each of the 15 sub-regions, is for residential accounts only, or whether it includes the commercial and light industrial and/or industrial accounts as well.

RESPONSE:

The residential account forecast is the only forecast that is developed at the 15 sub-regions level.

For further information on the development of the accounts forecast for the commercial and light industrial sectors, please refer to BC Hydro's response to BCOAPO IR 2.99.1.

For further information on the development of the accounts forecast for the large industrial sector, please refer to BC Hydro's response to BCOAPO IR 2.99.3.

4.0 References: Gjoshe IR 1.1.4 and Gjoshe IR 1.1.5

2.4 In response to Gjoshe IR 1.1.4 BC Hydro states: ‘To clarify, the regional breakdown of BC Hydro’s SAE models is to each of the four regions, and not for each of the 15 sub-regions. BC Hydro develops an account forecast for each of the 15 sub-regions, which is aggregated for use in the four SAE regional models.”

In response to Gjoshe IR 1.1.5 BC Hydro states: ‘To clarify, the residential and commercial SAE sales forecasts are not developed at the sub-region level. The 15 sub-regions are used to determine the forecast number of residential accounts and use per account which are then aggregated into the four regional SAE models.’

2.4.2 Please discuss potential benefits to the load forecasting process and/or the accuracy of load forecasts, from full delineation of the load forecasting process in each of the 15 sub-regions. What is meant by full delineation, is building load forecasts from the bottom up (in consideration of a synchronized view of all of residential, commercial and industrial drivers in each of the regions) for each of the 15 sub-regions, to derive a provincial forecast.

RESPONSE:

This answer also responds to GJOSHE IRs 2.4.3 and 2.4.5.

BC Hydro interprets “the slicing of the provincial forecast largely by customer segment (residential, commercial, industrial)” as stated in GJOSHE IR 2.4.3 as a general characterization of BC Hydro’s existing energy forecast process. At a high level BC Hydro’s existing energy forecasting process for the main customer sectors involves the following aspects:

- **The load forecast for the residential sector is developed for four regions and summed to a service area level total;**
- **The load forecast for the commercial sector is developed for four regions and summed to a service area level total;**
- **The load forecasts for the light industrial sector are developed:**
  - **On a customer basis for the coal and oil and gas sub-sectors;**
  - **On a regional basis for the forestry sub-sector and then summed to a total service area level; and**

- **On a total service area level for other light industrial sub-sectors (i.e., loads excluding forestry, coal and oil and gas) the forecast is developed at the total service area level;**

- **Load forecasts for the large industrial customers are developed for each customer and summed to a total service area level; and**
- **Adjustments for rate impacts and load reductions for Demand Side Management (DSM) are subtracted from the forecasts for the main customer sectors and the net load is then aggregated at the total service area level.**

BC Hydro interprets the phrase "full delineation of the load forecasting process" to differ from BC Hydro's existing process in the following ways:

- **Developing the load forecast for the main customer sectors at each of the 15 sub-regions, including reductions for rate impacts and DSM savings; and**
- **The 15 sub-regional load forecast would then be summed to a total service area level on an after rate impact and DSM savings basis.**

Given these descriptions of the two forecasting processes, we believe there is some overlap between the proposed 15 sub-regional approach and our current process. For example, several load forecasts for sub-sectors that make up the light industrial sector and load forecasts for the large industrial sector are already done at the customer level, and those customer forecasts can easily be segmented into a 15 sub-regional view.

Despite these overlaps, there are both potential benefits and draw backs to developing a load forecast at the 15 sub-regional level. The benefits could be a further alignment of the historical sales to economic drivers on a sub-regional basis by developing sub-regional residential and commercial SAE models. The drawback is the recalibration of the SAE models with more granular data that may not be as robust as the data from the four regions. This may introduce further forecasting error. For example, there may not be enough responses to BC Hydro's residential end use survey (REUS) from smaller regions to generate a statistically significant sample of the historical shares of the residential end uses which is used in the residential SAE models.

To assess the drawbacks and benefits, we would have to undertake significant analysis including the development of 15 sub-regional models. This analysis could also include re-estimating the May 2016 Load Forecast to assess the differences in the forecasts to examine the change in the historical accuracy. The October 2018 Load Forecast would also need to be re-developed to assess its forecast accuracy. The analysis would require additional time and resources to complete.

A more granular load forecast process may also require more time and effort to complete, which may adversely impact our ability to develop load forecasts on a timely basis.

For example, developing the residential and commercial forecasts, before DSM savings, at a more granular sub-regional basis would require additional time to estimate and check the statistical properties of 15 models relative to four models.

There would be minimal implications to developing the load forecasts for these sectors after rate impacts and DSM saving on a sub-regional basis, with the following caveats:

- **Rate impacts, which are projections of customer response to general rate increases, are formula based calculations involving price elasticity, and can be computed at various levels of aggregation such as sector, region or system; and**
- **Currently, DSM planning and projects occur on a system wide basis. Assuming this would continue, there would be no further implications to developing a load forecast at a sub-regional basis given that system wide DSM savings projections could be allocated to the sub-regions.**

However, if the proposal is to develop 15 sub-regional load forecasts based on DSM planning and projections of savings at this level, BC Hydro believes that there would be further implications for developing a DSM plan and a load forecast at this lower level.

In summary, developing a residential and commercial forecast on a sub-regional level entails trade-offs between the possibility of improved accuracy (or less) and the time needed to develop our load forecast on a timely basis. BC Hydro believes that making significant changes to the existing process are not warranted in light of the following:

- **The most recent historical residential and commercial forecasts using the current process have been accurate and have low variances. For further information on the short-term variance please refer to Appendix G of the Application and the Evidentiary Update; and**
- **The load forecast audit completed in fiscal 2018 concluded that BC Hydro's load forecasting methodologies are consistent with best practices.**

4.0 References: Gjoshe IR 1.1.4 and Gjoshe IR 1.1.5

2.4 In response to Gjoshe IR 1.1.4 BC Hydro states: ‘To clarify, the regional breakdown of BC Hydro’s SAE models is to each of the four regions, and not for each of the 15 sub-regions. BC Hydro develops an account forecast for each of the 15 sub-regions, which is aggregated for use in the four SAE regional models.”
In response to Gjoshe IR 1.1.5 BC Hydro states: ‘To clarify, the residential and commercial SAE sales forecasts are not developed at the sub-region level. The 15 sub-regions are used to determine the forecast number of residential accounts and use per account which are then aggregated into the four regional SAE models.’

2.4.3 Please discuss the trade-offs to the load forecasting process, as it concerns developing or “slicing” of the provincial forecast largely by customer segment (residential, commercial, industrial) versus developing of the provincial forecast from the 15 sub-regional forecasts, then slicing by customer segment at the provincial level for revenue forecasting purposes.

RESPONSE:

Please refer to BC Hydro’s response to GJOSHE IR 2.4.2.

4.0 References: Gjoshe IR 1.1.4 and Gjoshe IR 1.1.5

2.4 In response to Gjoshe IR 1.1.4 BC Hydro states: 'To clarify, the regional breakdown of BC Hydro's SAE models is to each of the four regions, and not for each of the 15 sub-regions. BC Hydro develops an account forecast for each of the 15 sub-regions, which is aggregated for use in the four SAE regional models."

In response to Gjoshe IR 1.1.5 BC Hydro states: 'To clarify, the residential and commercial SAE sales forecasts are not developed at the sub-region level. The 15 sub-regions are used to determine the forecast number of residential accounts and use per account which are then aggregated into the four regional SAE models.'

2.4.4 Please discuss the importance of potential interactions between industrial load developments on one hand, and commercial and/or residential impacts, on the other hand, especially for those regions of the province that depend heavily on single industries (such as forestry, oil & gas, mining, etc.). Please depict or provide examples of such potential interactions, and the possibility of monitoring industrial trends or developments not only for purposes of deriving the industrial load forecast, but as well for potential interactions with or spill-over effects to the commercial and residential loads, especially for those regions that are heavily impacted by changes in the fortunes of industries that singularily or primarily drive them.

RESPONSE:

BC Hydro believes the existing load forecast process adequately captures the interactions between industrial load developments, and residential and commercial activities. This is accomplished by having a comprehensive economic forecast developed at a 15 sub-regional level. The inputs to the economic forecast include regionally-based large industrial sector information such as natural gas production forecasts. Regionally specified major projects are also included in the economic forecast. These projects have regional capital spending impacts which inform regional housing and employment forecasts. Housing and employment forecasts are then used to develop the regional residential and commercial load forecasts.

For further information on the Conference Board of Canada's June 2018 economic forecast, which was an input into the October 2018 Residential and Commercial Load Forecast please refer to BC Hydro's response to BCUC IR 1.6.1.

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British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit:** **B-13**

4.0 References: Gjoshe IR 1.1.4 and Gjoshe IR 1.1.5

2.4 In response to Gjoshe IR 1.1.4 BC Hydro states: 'To clarify, the regional breakdown of BC Hydro's SAE models is to each of the four regions, and not for each of the 15 sub-regions. BC Hydro develops an account forecast for each of the 15 sub-regions, which is aggregated for use in the four SAE regional models."
In response to Gjoshe IR 1.1.5 BC Hydro states: 'To clarify, the residential and commercial SAE sales forecasts are not developed at the sub-region level. The 15 sub-regions are used to determine the forecast number of residential accounts and use per account which are then aggregated into the four regional SAE models.'

2.4.5 As DSM and Rate Impacts are typically accounted for in the latter stages of the load forecasting process, please discuss potential implications to the load forecasting process from consideration of building the provincial load forecast up from 15 sub-regional forecasts.

RESPONSE:

Please refer to BC Hydro's response to GJOSHE IR 2.4.2.

4.0 References: Gjoshe IR 1.1.4 and Gjoshe IR 1.1.5

2.4 In response to Gjoshe IR 1.1.4 BC Hydro states: 'To clarify, the regional breakdown of BC Hydro's SAE models is to each of the four regions, and not for each of the 15 sub-regions. BC Hydro develops an account forecast for each of the 15 sub-regions, which is aggregated for use in the four SAE regional models."
In response to Gjoshe IR 1.1.5 BC Hydro states: 'To clarify, the residential and commercial SAE sales forecasts are not developed at the sub-region level. The 15 sub-regions are used to determine the forecast number of residential accounts and use per account which are then aggregated into the four regional SAE models.'

2.4.6 Please discuss the possibility of learning (i.e. regional learning) and feedback loops to DSM and Rate Impacts (if any), from a load forecasting process that would see the provincial load forecast be built up from 15 sub-regional forecasts.

RESPONSE:

As discussed in BC Hydro's response to GJOSHE IR 2.4.2, there are both potential benefits and drawbacks to developing a load forecast at the 15 sub-regional basis. To assess any benefits and drawbacks, we would have to undertake significant analysis including the development of 15 sub-regional models, and it is unknown whether this change would improve forecast accuracy. It is also expected that there would also be additional costs in time and resources associated with developing and applying the new methodology.

To achieve the suggested learning and feedback loops with the more granular load forecast, it is likely that DSM planning would similarly need to move to a more granular level. However, it is not clear at this time whether it would be desirable to do so. In particular, there would be similar trade-offs as described above to move to a more granular DSM planning process. A potential benefit of moving to a more granular DSM planning process could be to provide more accurate information at the regional level, which could be useful to inform potential DSM programs targeted to a regional level. A cost of moving to a more granular DSM planning process would result from the requirement to research and maintain accurate information on end uses and conservation measures at a regional level (also, there may not be significant differences with how customers use electricity and opportunities to save electricity over the 15 regions or improvements in accuracy by maintaining the information at that level).

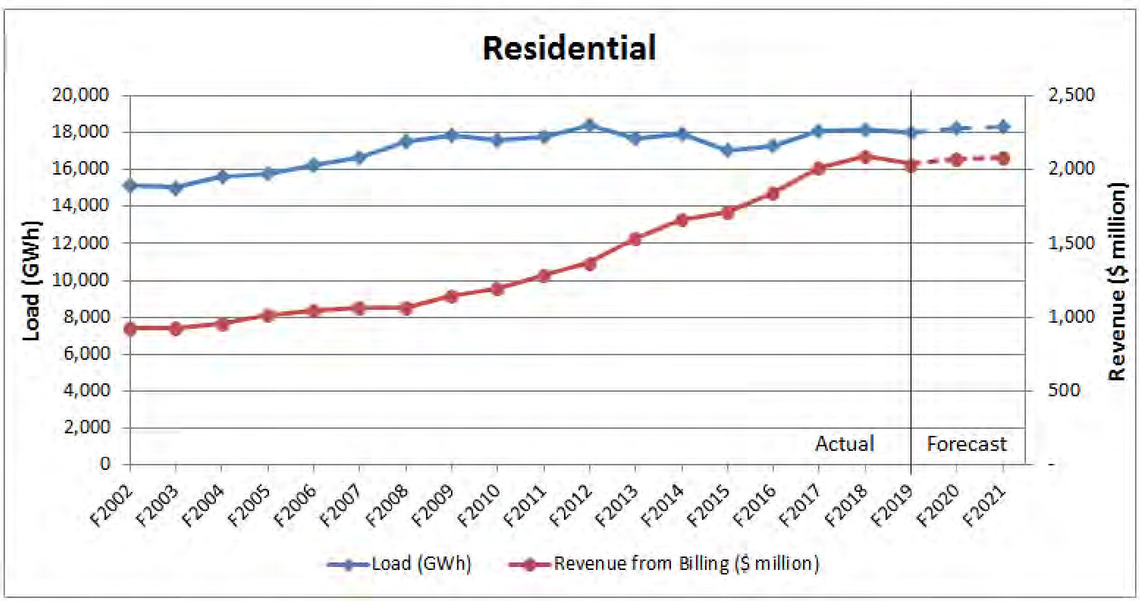
At this time, it is not clear that the potential benefit of moving to a more granular planning process (i.e. 15 regions) would outweigh the costs. BC Hydro will continue to assess the benefits of this as its needs evolve.

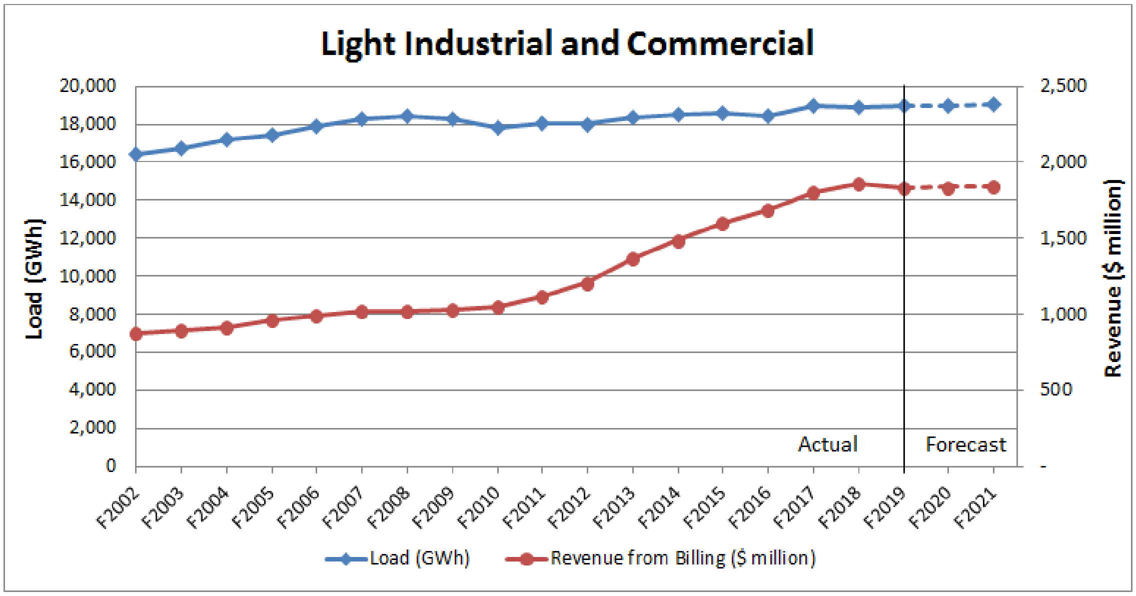
5.0 Reference: Gjoshe IR 1.3.3

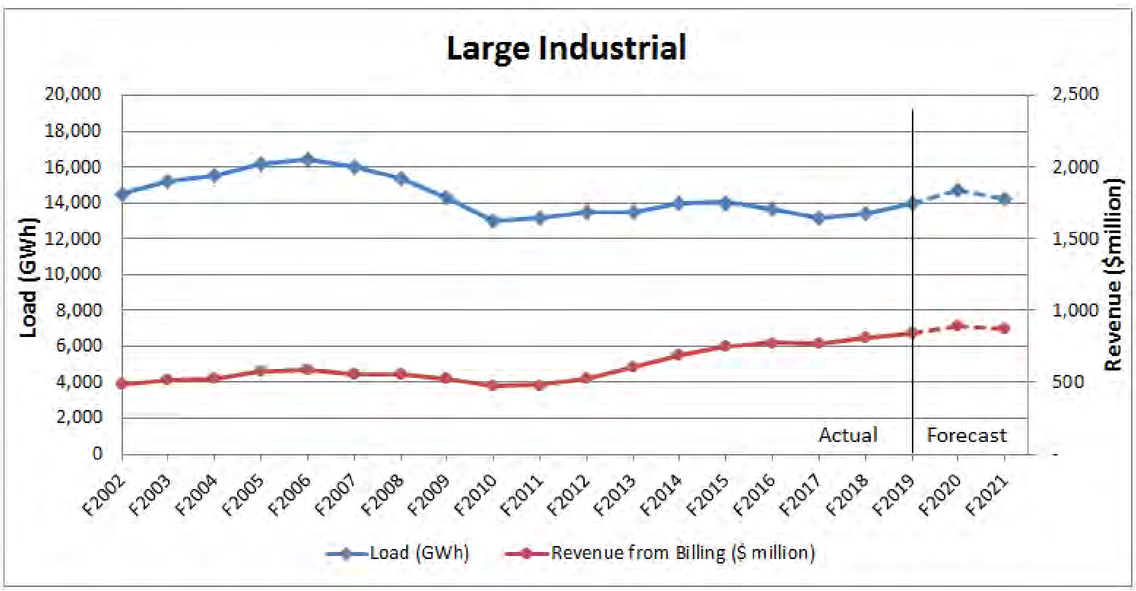
2.5 As requested in Gjoshe IR 1.3.3, please provide a line graph of the F2002-F2021 'Load' and 'Revenue from Billing'.

RESPONSE:

The requested graphs are provided below and have been prepared using the data provided in BC Hydro's response to GJOSHE IR 1.2.2.







Notes:

1. **Actuals from fiscal 2014 to fiscal 2018 are based on BC Hydro's Fiscal 2018 Annual Report, located at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/BCHydro-Crown-Corporation-2017-18-Annual-Report.pdf.**

   Actuals for years prior to fiscal 2014 are based on previous Annual Reports, summarized in BC Hydro's response to Skywind Foundation IR 1.2.1 from the Previous Application.
2. **Forecast sales and revenues are based on Schedule 14.0 of Appendix A of the Application.**
3. **Forecasts of accounts are based on the October 2018 Load Forecast.**

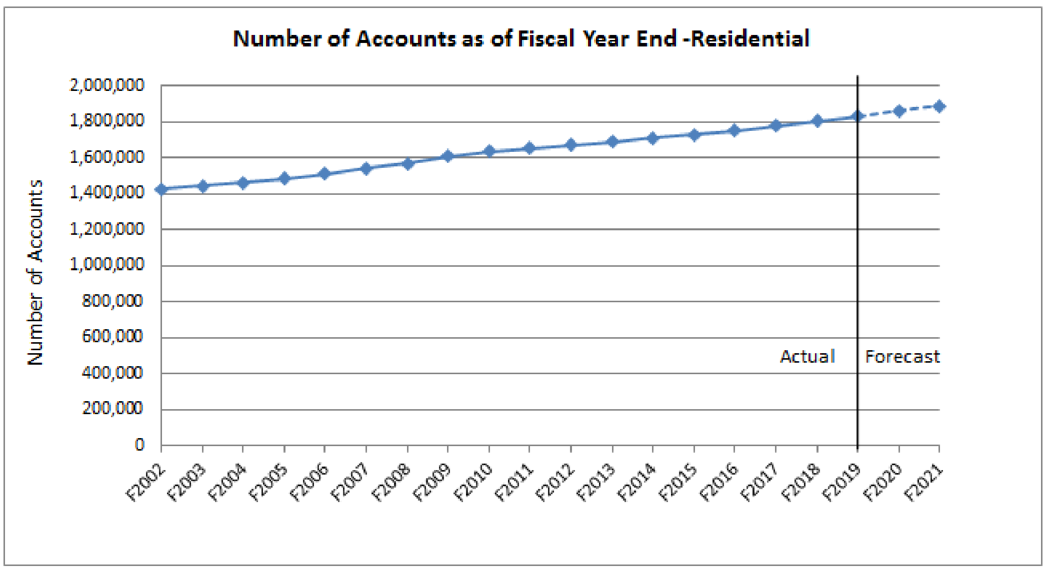
Edlira Gjoshe Information Request No. **2.6** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 2
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit:** **B-13**

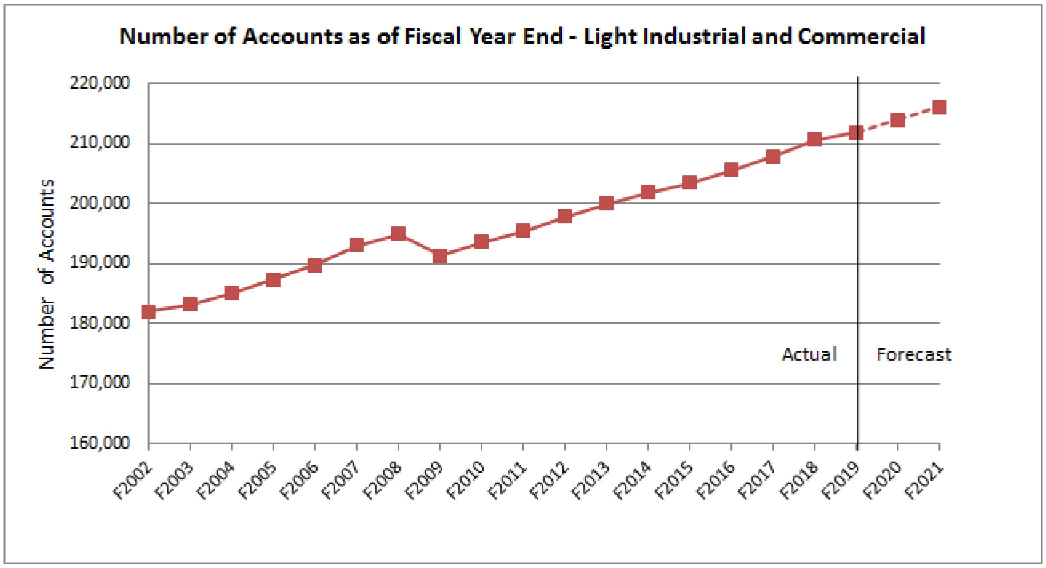
6.0 Reference: Gjoshe IR 1.3.4

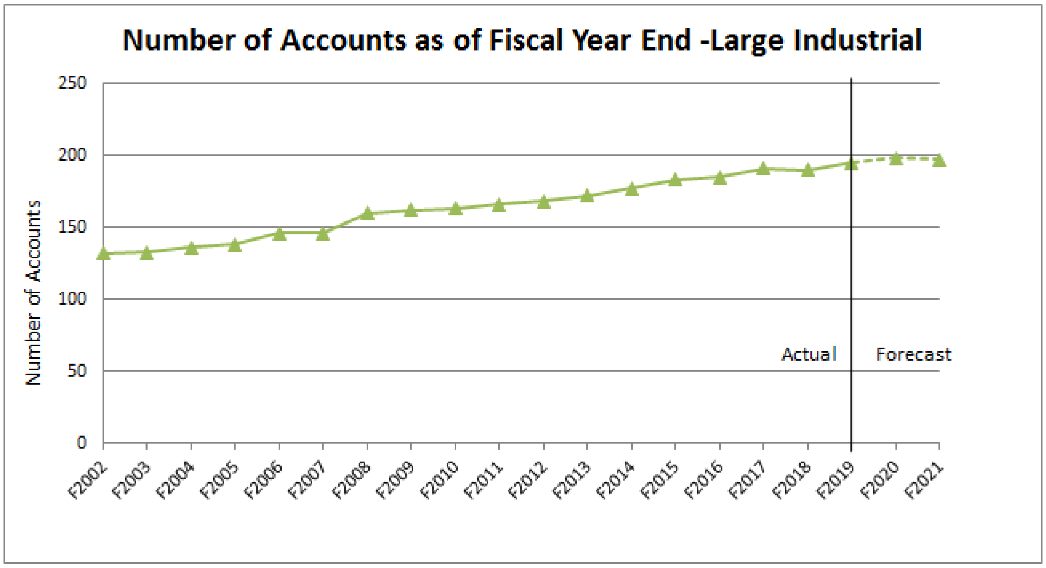
2.6 As per Gjoshe IR 1.3.4, please provide a line graph of the F2002-F2021 'Number of Accounts as at Fiscal Year End' by sector.

RESPONSE:

Please find the requested graphs below, prepared using the data provided in BC Hydro's response to GJOSHE IR 1.2.2.







Notes:

1. **Actuals from fiscal 2014 to fiscal 2018 are based on BC Hydro's Fiscal 2018 Annual Report, located at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bc-hydro-annual-service-plan-report-2017-2018.pdf.**
2. **Actuals for years prior to fiscal 2014 are based on previous annual reports, which are summarized in BC Hydro's response to Skywind Foundation IR 1.2.1 from the Previous Application.**
3. **Forecast sales and revenues come from Schedule 14.0 of Appendix A of the Application.**
4. **Forecasts of accounts are based on the October 2018 Load Forecast.**

7.0 Reference: Gjoshe IR 1.3.5

2.7 Please provide line graphs (three) of the F2002-F2021 'Average Annual Consumption per Account' and 'Average Annual Revenue per Account' for each sector (Residential, Commercial and Industrial).

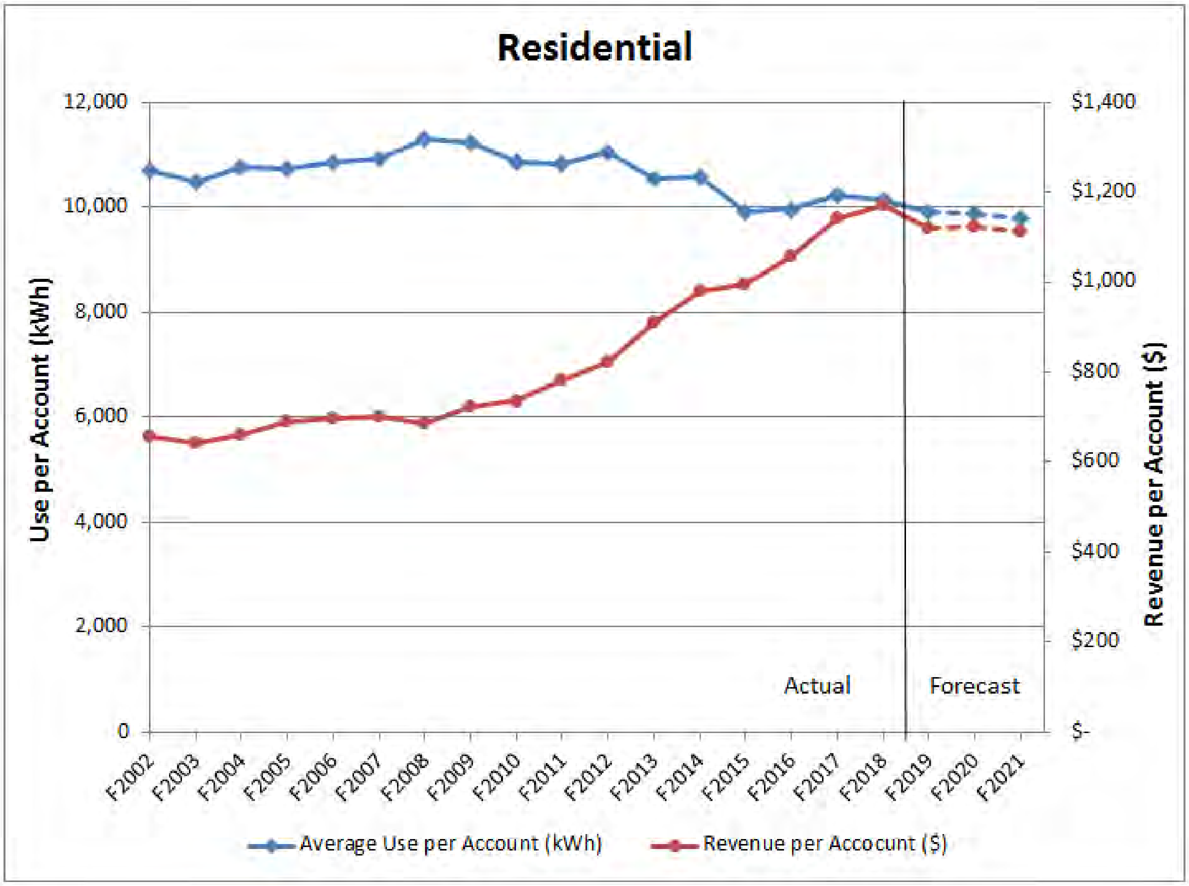
RESPONSE:

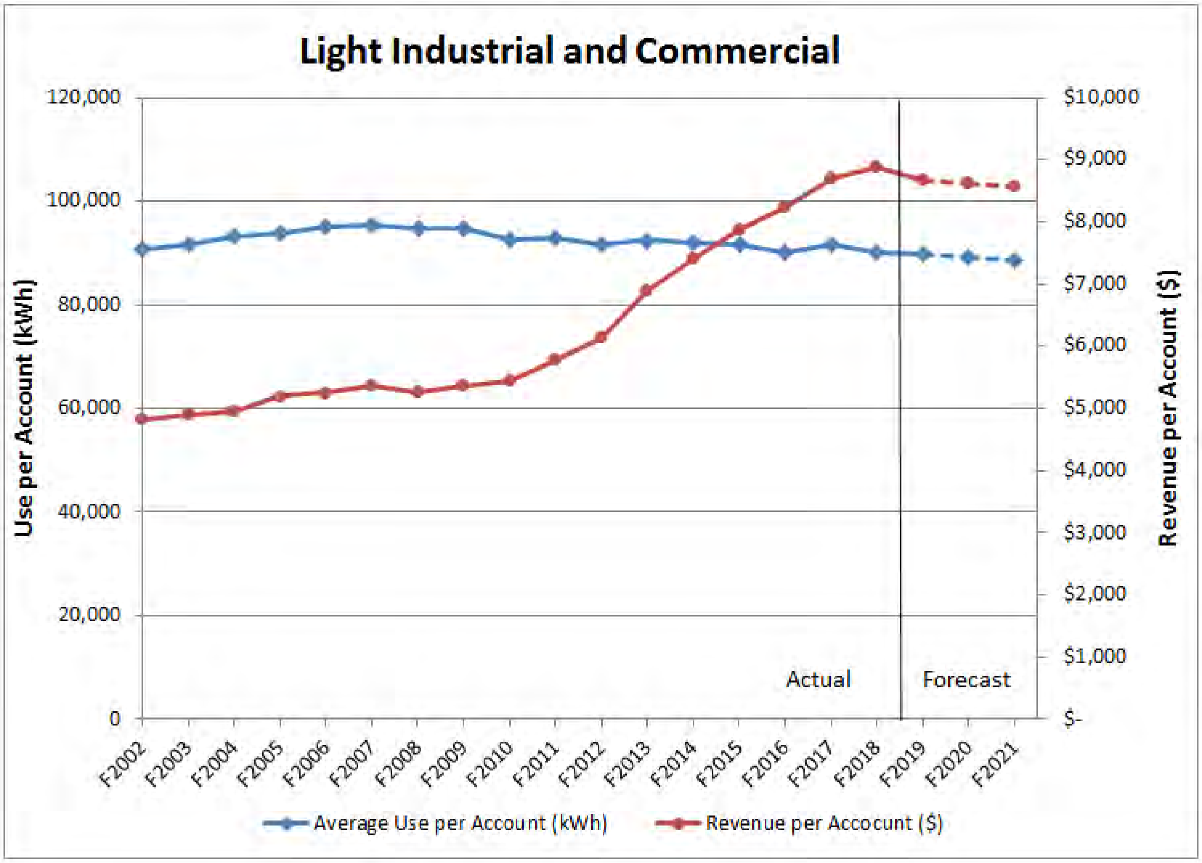
The requested line graphs, based on the data provided in BC Hydro's response to GJOSHE IR 1.2.2, are provided below.

The Average Revenue per Account was calculated by dividing the Revenues from Billing by the Average Number of Accounts.

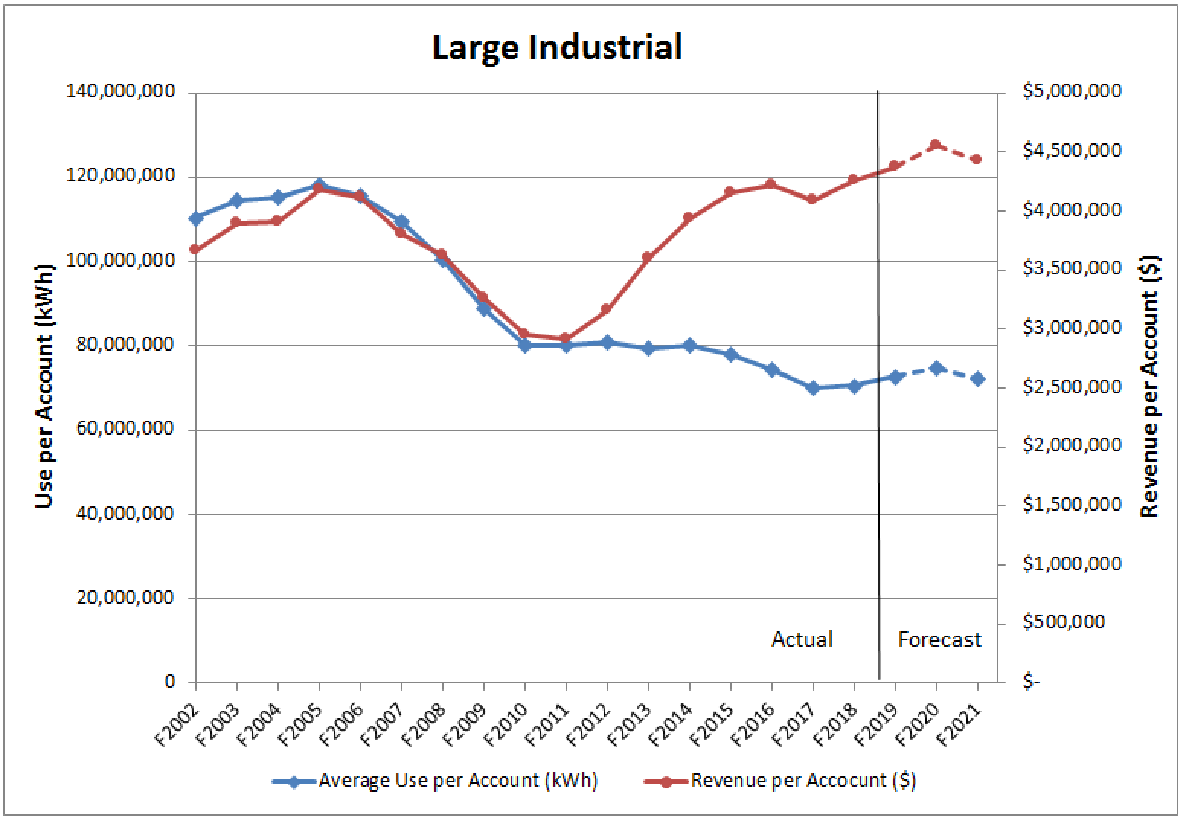
In responding to this question, BC Hydro noticed an error in Attachment 1 to our response to GJOSHE IR 1.2.2. The last table was labelled "Revenue per Account" when it should have been labelled "(cents/KWh)", consistent to the data provided in the table. A corrected table is provided below.

Revenue per Account cents/KWh				
			Light Industrial and	
		Residential	Commercial	Large Industrial
	Fiscal Year	~~Revenue per Account~~ (cents/ kWh)		
Actual	F1998			
Actual	F1999	6.113	5.312	3.319
Actual	F2000	6.124	5.320	3.291
Actual	F2001	6.136	5.315	3.365
Actual	F2002	6.131	5.314	3.321
Actual	F2003	6.144	5.329	3.399
Actual	F2004	6.136	5.310	3.386
Actual	F2005	6.425	5.539	3.542
Actual	F2006	6.433	5.521	3.555
Actual	F2007	6.426	5.611	3.477
Actual	F2008	6.073	5.547	3.602
Actual	F2009	6.427	5.661	3.678
Actual	F2010	6.775	5.890	3.679
Actual	F2011	7.232	6.210	3.646
Actual	F2012	7.448	6.715	3.897
Actual	F2013	8.643	7.441	4.523
Actual	F2014	9.257	8.048	4.909
Actual	F2015	10.043	8.603	5.335
Actual	F2016	10.628	9.147	5.677
Actual	F2017	11.136	9.490	5.844
Actual	F2018	11.554	9.855	6.034
Forecast	F2019	11.290	9.657	6.007
Forecast	F2020	11.353	9.677	6.090
Forecast	F2021	11.358	9.673	6.141


Residential
Use per Account (kWh)
Revenue per Account ($)
12,000
10,000
8,000
6,000
4,000
2,000
0
$1,400
$1,200
$1,000
$800
$600
$400
$200
$-
Actual
Forecast
F2002
F2003
F2004
F2005
F2006
F2007
F2008
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
F2017
F2018
F2019
F2020
F2021
Average Use per Account (kWh)
Revenue per Accocunt ($)



Light Industrial and Commercial
Use per Account (kWh)
Revenue per Account ($)
120,000
100,000
80,000
60,000
40,000
20,000
0
$10,000
$9,000
$8,000
$7,000
$6,000
$5,000
$4,000
$3,000
$2,000
$1,000
$-
Actual
Forecast
F2002
F2003
F2004
F2005
F2006
F2007
F2008
F2009
F2010
F2011
F2012
F2013
F2014
F2015
F2016
F2017
F2018
F2019
F2020
F2021
Average Use per Account (kWh)
Revenue per Accocunt ($)



Notes:

1. **Actuals from fiscal 2014 to fiscal 2018 are based on BC Hydro's Fiscal 2018 Annual Report, located at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bc-hydro-annual-service-plan-report-2017-2018.pdf.**
2. **Actuals for years prior to fiscal 2014 are based on previous annual reports, which are also summarized in BC Hydro's response to Skywind Foundation IR 1.2.1 from the Previous Application.**
3. **Forecast sales and revenues come from Schedule 14.0 of Appendix A of the Application.**
4. **Forecasts of accounts are based on the October 2018 Load Forecast.**

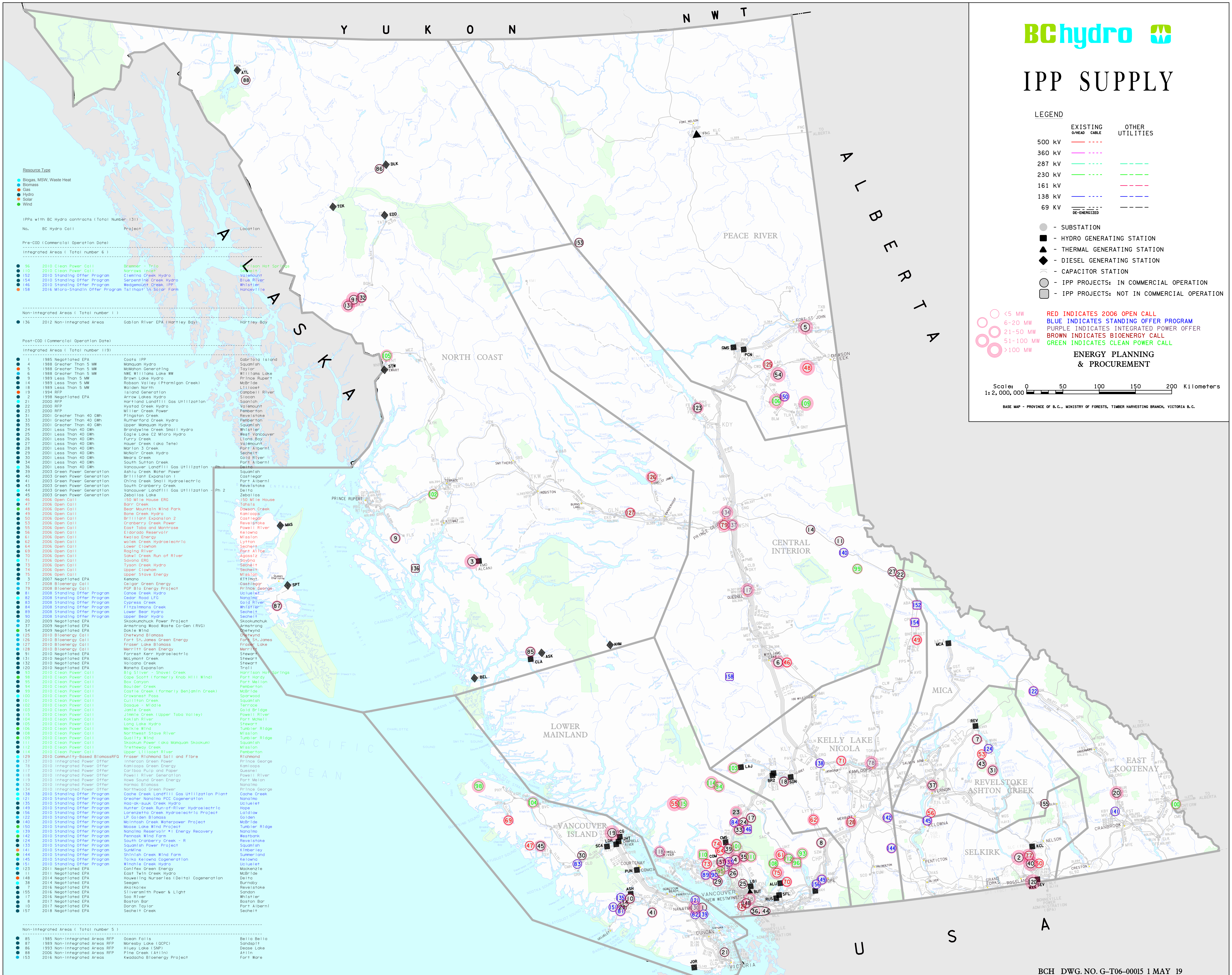
8.0 Reference: Gjoshe IR 1.4.1

2.8 Please provide the requested map. In the event of insufficient time to provide the map by the prescribed deadline, please indicate the required extra time (beyond the prescribed deadline) by which BC Hydro can provide the requested map.

RESPONSE:

The requested map is Attachment 1 to this response and reflects the existing and committed IPPs as of May 1, 2019. As of May 1, 2019, there were 131 IPP EPAs.

BC Hydro notes that at the time we responded to GJOSHE IR 1.4.1 the IPP map was current as of October 1, 2018. This map also reflects the existing and committed IPPs as of May 1, 2019. Since October 1, 2018 two EPAs, Seaton Creek and Morehead, have expired and there are no new contracts for these projects.


BC hydro
IPP SUPPLY
LEGEND
EXISTING
OTHER UTILITIES
500 kV
360 kV
287 kV
230 kV
161 kV
138 kV
69 KV
DE-ENERGIZED
- SUBSTATION
- HYDRO GENERATING STATION
- THERMAL GENERATING STATION
- DIESEL GENERATING STATION
- CAPACITOR STATION
- IPP PROJECTS: IN COMMERCIAL OPERATION
- IPP PROJECTS: NOT IN COMMERCIAL OPERATION
<5 MW
6-20 MW
21-50 MW
51-100 MW
>100 MW
RED INDICATES 2006 OPEN CALL
BLUE INDICATES STANDING OFFER PROGRAM
PURPLE INDICATES INTEGRATED POWER OFFER
BROWN INDICATES BIOENERGY CALL
GREEN INDICATES CLEAN POWER CALL
ENERGY PLANNING & PROCUREMENT
Scale: 1:2,000,000 0 50 100 150 200 Kilometers
BASE MAP - PROVINCE OF B.C., MINISTRY OF FORESTS, TIMBER HARVESTING BRANCH, VICTORIA B.C.
Y U K O N
N W T
A L B E R T A
A L A S K A
U S A
PEACE RIVER
NORTH COAST
CENTRAL INTERIOR
MICA
KELLY LAKE NICOLA
LOWER MAINLAND
VANCOUVER ISLAND
REVELSTOKE ASHTON CREEK
SELKIRK
EAST KOOTENAY
P A C I F I C O C E A N
BCH DWG. NO. G-T06-00015 1 MAY 19

9.0 Reference: Gjoshe IR 1.4.2

2.9 Thank you for the two versions (respectively reducted and unreducted) of the answer to Gjoshe IR 1.4.2. Further to the information provided:

2.9.1 Please amend Table 1 to include columns indicating a) the type of clean energy project (wind, solar, run-of-river, biomass, etc.); b) an indication of whether the project supplies baseload (steady power throughout the year), winter-peaking or freshet/summer peaking energy supply, c) where applicable other significant potential power system benefits associated with the operation of IPP projects, including but not limited to: synergies with other industries (i.e. such as forestry, waste management, etc.), servicing of local load, voltage support to local systems, and other potential system benefits.

RESPONSE:

The public version of the response to this information request has been redacted to maintain confidentiality. The un-redacted version of this response is being made available to the BCUC only, in order to protect IPPs' commercial interests. The public disclosure of the redacted information could also impact BC Hydro's commercial interests and ongoing negotiations related to the EPAs.

In regards to item (a) in the question, the table below provides a modified version of Table 1 from BC Hydro's response to GJOSHE IR 1.4.2 to include an additional column that indicates the resource type for each of the EPAs listed. Values shown are as of October 1, 2018 for the integrated system.

In regards to item (b) in the question, the generation profile for each EPA typically depends on the resource type which can be generally categorized as follows:

- **Biomass, biogas, waste heat, and municipal solid waste facilities typically provide baseload generation;**
- **Wind and solar facilities typically provide intermittent generation without peaking capability;**
- **Run-of-river hydro facilities typically provide freshet-driven generation without peaking capability;**
- **Storage hydro facilities are less freshet-driven but are not capable of peaking without contractual dispatch rights; and**

- **Island Generation provides year-round dispatchable capacity.**

In regards to item (c) in the question, BC Hydro does not track all potential power system benefits associated with the operation of IPP projects. BC Hydro generally works with IPP projects seeking their cooperation for managing the system operation.

BC Hydro notes the following with respect to the values shown below:

- **The start dates shown reflect the original commercial operation date (COD) for each facility. As a result, where an EPA has been renewed, the original commercial operation date for the project continues to be shown;** [1]
- **The historical energy volumes were averaged using data from fiscal 2002 to fiscal 2018. There were no adjustments made to the historical energy data to account for issues impacting generation, such as outages. For projects that reached COD within the available data range, the first year was eliminated to exclude partial year effects; and**
- **For projects that reached COD during fiscal 2018 and thereafter, where data for a full year is not available, the historical energy is indicated as "N/A".**

Project Name	Actual Commercial Operations Date (yyyy-mm-dd)	Installed Capacity (MW)	Historical Energy (GWh/year)	Technology Type
150 Mile House ERG	[redacted]	6.0	[redacted]	Waste Heat
Akolkolex	[redacted]	10.0	[redacted]	Run-of-river
Armstrong Wood Waste Co-Gen (RVG)	[redacted]	20.4	[redacted]	Biomass
Arrow Lakes Hydro	[redacted]	185.0	[redacted]	Storage Hydro
Ashlu Creek Water Power	[redacted]	49.9	[redacted]	Run-of-river
Barr Creek	[redacted]	4.0	[redacted]	Run-of-river
Bear Mountain Wind Park	[redacted]	102.0	[redacted]	Wind
Big Silver - Shovel Creek	[redacted]	40.6	[redacted]	Run-of-river
Bone Creek Hydro	[redacted]	20.0	[redacted]	Run-of-river
Boston Bar	[redacted]	9.0	[redacted]	Run-of-river
Boulder Creek	[redacted]	25.3	[redacted]	Run-of-river
Box Canyon	[redacted]	14.7	[redacted]	Run-of-river
Brandywine Creek Small Hydro	[redacted]	7.6	[redacted]	Run-of-river

[1] **BC Hydro notes that commercial operation date means the date upon which the facility started to sell energy under an EPA to BC Hydro; however, there are some facilities (e.g., Kemano) which were in operations before their EPA commercial operation date with BC Hydro.**

Project Name	Actual Commercial Operations Date (yyyy-mm-dd)	Installed Capacity (MW)	Historical Energy (GWh/year)	Technology Type
Brilliant Expansion 1	[redacted]	120.0	[redacted]	Storage Hydro
Brilliant Expansion 2	[redacted]	<0.5	[redacted]	Storage Hydro
Brown Lake	[redacted]	7.2	[redacted]	Storage Hydro
Cache Creek Landfill Gas Utilization Plant	[redacted]	4.8	[redacted]	Biogas
Canoe Creek Hydro	[redacted]	5.5	[redacted]	Run-of-river
Cape Scott (formerly Knob Hill Wind)	[redacted]	99.2	[redacted]	Wind
Cariboo Pulp and Paper	[redacted]	61.3	[redacted]	Biomass
Castle Creek (formerly Benjamin Creek)	[redacted]	6.0	[redacted]	Run-of-river
Cedar Road LFG	[redacted]	1.3	[redacted]	Biogas
Celgar Green Energy	[redacted]	78.0	[redacted]	Biomass
Chetwynd Biomass	[redacted]	12.0	[redacted]	Biomass
China Creek Small Hydroelectric	[redacted]	6.3	[redacted]	Run-of-river
Coats IPP	[redacted]	<0.5	[redacted]	Run-of-river
Conifex Green Energy	[redacted]	36.0	[redacted]	Biomass
Cranberry Creek Power	[redacted]	3.0	[redacted]	Run-of-river
Crowsnest Pass	[redacted]	10.5	[redacted]	Waste Heat
Culliton Creek	[redacted]	15.0	[redacted]	Run-of-river
Cypress Creek	[redacted]	2.8	[redacted]	Run-of-river
Dasque - Middle	[redacted]	20.0	[redacted]	Run-of-river
Dokie Wind	[redacted]	144.0	[redacted]	Wind
Doran Taylor	[redacted]	6.0	[redacted]	Run-of-river
Eagle Lake C2 Micro Hydro	[redacted]	<0.5	[redacted]	Run-of-river
East Toba and Montrose	[redacted]	196.0	[redacted]	Run-of-river
East Twin Creek Hydro	[redacted]	1.6	[redacted]	Run-of-river
Eldorado Reservoir	[redacted]	1.1	[redacted]	Storage Hydro
Fitzsimmons Creek	[redacted]	7.9	[redacted]	Run-of-river
Forrest Kerr Hydroelectric	[redacted]	195.0	[redacted]	Run-of-river
Fort St. James Green Energy	[redacted]	40.0	[redacted]	Biomass
Fraser Lake Biomass	[redacted]	12.0	[redacted]	Biomass
Fraser Richmond Soil and Fibre	[redacted]	1.0	[redacted]	Biogas

Project Name	Actual Commercial Operations Date (yyyy-mm-dd)	Installed Capacity (MW)	Historical Energy (GWh/year)	Technology Type
Furry Creek	[redacted]	10.4	[redacted]	Run-of-river
Greater Nanaimo PCC Cogeneration	[redacted]	<0.5	[redacted]	Biogas
Haa-ak-suuk Creek Hydro	[redacted]	6.0	[redacted]	Run-of-river
Harmac Biomass	[redacted]	55.0	[redacted]	Biomass
Hartland Landfill Gas Utilization	[redacted]	1.8	[redacted]	Biogas
Hauer Creek (Tete)	[redacted]	2.4	[redacted]	Run-of-river
Houweling Nurseries Cogeneration	[redacted]	8.8	[redacted]	Gas Fired Thermal
Howe Sound Green Energy	[redacted]	112.0	[redacted]	Biomass
Hunter Creek Run-of-River	[redacted]	10.97	[redacted]	Run-of-river
Hystad Creek Hydro	[redacted]	6.0	[redacted]	Run-of-river
Intercon Green Power	[redacted]	31.7	[redacted]	Biomass
Island Generation	[redacted]	275.0	[redacted]	Gas Fired Thermal
Jamie Creek	[redacted]	21.3	[redacted]	Run-of-river
Jimmie Creek (Upper Toba Valley)	[redacted]	62.0	[redacted]	Run-of-river
Kamloops Green Energy	[redacted]	76.0	[redacted]	Biomass
Kemano (Alcan)	[redacted]	896.0	[redacted]	Storage Hydro
Kokish River	[redacted]	45.0	[redacted]	Run-of-river
Kwalsa Energy	[redacted]	90.0	[redacted]	Run-of-river
Kwoiek Creek Hydroelectric	[redacted]	50.0	[redacted]	Run-of-river
Long Lake Hydro	[redacted]	31.0	[redacted]	Storage Hydro
Lorenzetta Creek Hydroelectric Project	[redacted]	3.2	[redacted]	Run-of-river
Lower Bear Hydro	[redacted]	10.0	[redacted]	Run-of-river
Lower Clowhom	[redacted]	11.0	[redacted]	Run-of-river
LP Golden Biomass	[redacted]	7.5	[redacted]	Biomass
Mamquam Hydro	[redacted]	58.0	[redacted]	Run-of-river
Marion 3 Creek	[redacted]	4.6	[redacted]	Run-of-river
McIntosh Creek Waterpower Project	[redacted]	1.2	[redacted]	Run-of-river
McLymont Creek	[redacted]	66.0	[redacted]	Run-of-river
McMahon Generating	[redacted]	120.0	[redacted]	Gas Fired Thermal
McNair Creek Hydro	[redacted]	9.8	[redacted]	Run-of-river

Project Name	Actual Commercial Operations Date (yyyy-mm-dd)	Installed Capacity (MW)	Historical Energy (GWh/year)	Technology Type
Mears Creek	[redacted]	3.8	[redacted]	Run-of-river
Meikle Wind	[redacted]	184.6	[redacted]	Wind
Merritt Green Energy	[redacted]	40.0	[redacted]	Biomass
Miller Creek Power	[redacted]	29.5	[redacted]	Run-of-river
Morehead Creek	[redacted]	0.11	[redacted]	Run-of-river
Nanaimo Reservoir #1 Energy Recovery	[redacted]	<0.5	[redacted]	Waste Heat
Northwest Stave River	[redacted]	17.5	[redacted]	Run-of-river
Northwood Green Power	[redacted]	63.0	[redacted]	Biomass
NWE Williams Lake WW	[redacted]	67.7	[redacted]	Biomass
Pennask Wind Farm	[redacted]	15.0	[redacted]	Wind
PGP Bio Energy Project	[redacted]	59.9	[redacted]	Biomass
Pingston Creek	[redacted]	45.0	[redacted]	Run-of-river
Powell River Generation	[redacted]	48.0	[redacted]	Biomass
Quality Wind	[redacted]	142.2	[redacted]	Wind
Raging River	[redacted]	8.0	[redacted]	Run-of-river
Robson Valley (Ptarmigan Creek)	[redacted]	3.6	[redacted]	Run-of-river
Rutherford Creek Hydro	[redacted]	50.0	[redacted]	Run-of-river
Sakwi Creek Run of River	[redacted]	5.5	[redacted]	Run-of-river
Savona ERG	[redacted]	6.0	[redacted]	Waste Heat
Seaton Creek Hydro (Homestead)	[redacted]	<0.5	[redacted]	Run-of-river
Sechelt Creek (Salmon Inlet)	[redacted]	16.6	[redacted]	Run-of-river
Seegen	[redacted]	24.8	[redacted]	Municipal Solid Waste
Shinish Creek Wind Farm	[redacted]	15.0	[redacted]	Wind
Silversmith Power & Light	[redacted]	<0.5	[redacted]	Run-of-river
Skookum Power (Mamquam Skookum)	[redacted]	25.0	[redacted]	Run-of-river
Skookumchuck Power Project	[redacted]	51.3	[redacted]	Biomass
Soo River	[redacted]	13.1	[redacted]	Run-of-river
South Cranberry Creek	[redacted]	8.5	[redacted]	Run-of-river
South Cranberry Creek - R	[redacted]	<0.5	[redacted]	Run-of-river
South Sutton Creek	[redacted]	4.9	[redacted]	Run-of-river
Squamish Power Project	[redacted]	1.6	[redacted]	Storage Hydro
SunMine	[redacted]	1.1	[redacted]	Solar

Project Name	Actual Commercial Operations Date (yyyy-mm-dd)	Installed Capacity (MW)	Historical Energy (GWh/year)	Technology Type
Tolko Kelowna Cogeneration	[redacted]	14.9	[redacted]	Biomass
Tretheway Creek	[redacted]	21.2	[redacted]	Run-of-river
Tyson Creek Hydro	[redacted]	9.3	[redacted]	Storage Hydro
Upper Bear Hydro	[redacted]	10.0	[redacted]	Run-of-river
Upper Clowhom	[redacted]	11.0	[redacted]	Run-of-river
Upper Lillooet River	[redacted]	81.4	[redacted]	Run-of-river
Upper Mamquam Hydro	[redacted]	25.0	[redacted]	Run-of-river
Upper Stave Energy	[redacted]	60.0	[redacted]	Run-of-river
Vancouver Landfill Gas Utilization - Ph 1	[redacted]	5.5	[redacted]	Biogas
Vancouver Landfill Gas Utilization - Ph 2	[redacted]	1.9	[redacted]	Biogas
Volcano Creek	[redacted]	17.8	[redacted]	Run-of-river
Walden North	[redacted]	16.0	[redacted]	Run-of-river
Waneta Expansion	[redacted]	335.0	[redacted]	Run-of-river
Zeballos Lake	[redacted]	21.9	[redacted]	Storage Hydro

9.0 Reference: Gjoshe IR 1.4.2

2.9 Thank you for the two versions (respectively reducted and unreducted) of the answer to Gjoshe IR 1.4.2. Further to the information provided:

2.9.2 Please provide annual energy supply profiles of the aggregate energy supply of the IPP portfolio (whereby supply profiles show GWh's supplied in each month as a percentage of the annual energy supply), at five-year snapshots from F2002-F2021 (snapshots for each of F2002, F2007, F2012, F2017, and F2021- forecast).

RESPONSE:

This response includes confidential information that pertains to our August 2019 Cost of Energy Evidentiary Update, in accordance with Order No. G-146-19, which has been redacted in the public version of this response. The un-redacted version of the response is being made available to the BCUC only.

The table below provides the percentage of annual IPP energy delivered[1] in each month for the requested fiscal years. The last row in the table provides the forecast values for fiscal 2021 consistent with the Evidentiary Update (EU).

[1] **Values in the table for fiscal 2021 are forecast.**

%	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Total
F2002 Actual	**5.0**	**8.9**	**7.9**	**8.6**	**8.6**	**7.9**	**8.4**	**8.7**	**10.6**	**10.3**	**7.7**	**7.4**	**100**
F2007 Actual	**8.7**	**9.1**	**8.1**	**11.6**	**10.0**	**6.8**	**6.6**	**7.3**	**7.5**	**7.4**	**7.8**	**9.0**	**100**
F2012 Actual	**6.4**	**8.4**	**8.8**	**10.0**	**10.8**	**9.3**	**8.5**	**7.6**	**8.3**	**8.2**	**6.6**	**7.1**	**100**
F2017 Actual	**8.0**	**11.8**	**9.7**	**10.6**	**9.6**	**8.2**	**7.9**	**9.4**	**7.1**	**6.2**	**5.4**	**6.2**	**100**
F2021 RRA	**7.3**	**10.3**	**10.6**	**10.8**	**9.9**	**8.4**	**8.4**	**7.7**	**7.4**	**7.1**	**6.1**	**5.8**	**100**
F2021 EU	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**100**

10.0 References: Gjoshe IR 1.7.1, Gjoshe IR 1.7.2, Gjoshe IR 1.12.1 and Gjoshe IR 1.12.2

2.10 Please explain as to whether there is an opportunity to assess benefits arising from contribution to increased system diversity, as a project moves from Initiation (need) to Identification (of alternatives), to Definition (selection of the preferred alternative).

RESPONSE:

As explained in BC Hydro's response to GJOSHE IR 1.7.1, BC Hydro interprets power system diversity to mean a measure of the diversity of electricity supply resources on the integrated system (e.g., wind, hydro and biomass resources) or the diversity of supply regions (e.g., resources located in various regions of the province) that may result in complimentary characteristics that benefit the overall power system.

BC Hydro believes there is limited opportunity to assess system diversity as the project moves through the project life-cycle. Rather, system diversity is reflected in the planning process through detailed portfolio modelling of various resources and alternatives.

11.0 References: Gjoshe IR 1.6.1, Gjoshe IR 1.6.2, Gjoshe IR 1.13.1 and Gjoshe IR 1.14.2

2.11 In its responses to Gjoshe IR 1.6.1, Gjoshe IR 1.6.2, Gjoshe IR 1.13.1 and Gjoshe IR 1.14.2, BC Hydro provides costs figures in the respective included tables:

2.11.1 Please confirm that the costs are in nominal dollars (in corresponding Fiscal Year dollars).

RESPONSE:

Confirmed.

11.0 References: Gjoshe IR 1.6.1, Gjoshe IR 1.6.2, Gjoshe IR 1.13.1 and Gjoshe IR 1.14.2

2.11 In its responses to Gjoshe IR 1.6.1, Gjoshe IR 1.6.2, Gjoshe IR 1.13.1 and Gjoshe IR 1.14.2, BC Hydro provides costs figures in the respective included tables:

2.11.2 Please provide the recommended discount rate, by Fiscal Year (for each of F2002-F2021), to be used in financial calculations and/or conversion.

RESPONSE:

BC Hydro generally uses a real discount rate of 3.90 per cent for financial evaluation purposes to discount future year cash flows. However, if the objective is to convert past capital expenditures into 2019 dollars, the following formula could be used:

$FV = NV(1 + i)^n$

FV = future value in 2019 dollars

NV = nominal value in a given past year

i = inflation rate

n = number of compounding years

12.0 Reference: Gjoshe IR 1.15.1

2.12 In its response to Gjoshe IR 1.15.1, BC Hydro explains some of the system benefits from DSM spending, in an energy surplus environment. Please provide a more in depth discussion of system benefits (or costs) arising from DSM program spend, specifically for those areas of the system (localized or broader) that have benefited or are benefiting from simultaneous (with the DSM program spend) generation and/or transmission build.

RESPONSE:

As described in BC Hydro's response to GJOSHE IR 1.15.1, in an energy surplus environment, system benefits from DSM investments include:

1. **An increase in energy export opportunities – energy savings from DSM activities will increase the amount of energy available for export; as the cost of DSM is less than market price, this will reduce BC Hydro's overall revenue requirement.**
2. **Associated capacity savings from DSM activities will reduce system capacity requirements – this reduction in system peak needs is reflected in the load resource balance for capacity. In turn, this will defer the need for generation capacity resources during times of system capacity constraints.**
3. **Transmission and Distribution planners use the substation-level and regional-level net load forecasts to prepare BC Hydro's capital plan. The net load forecast includes the savings from DSM activities. The net load forecast is lower than what it would be otherwise without the DSM savings. By lowering the load forecast, the DSM savings would, in effect, delay the timing of planned growth-related infrastructure investments.**

Also, as described in BC Hydro's response to GJOSHE IR 1.15.2, we are exploring the possibility to relieve specific localized or regional constraints by applying additional area-focused DSM efforts to lower the peak demand. The objective would be to cost-effectively defer / delay the need of growth-related infrastructure investments.

13.0 References: Gjoshe IR 1.6.3, Gjoshe IR 1.17.1 and Gjoshe IR 1.17.2

2.13 The term ‘Enterprise Value’ is often used in financial performance as a measure of a publicly-listed company’s total value, beyond market capitalization; and is estimated as ‘Market Capitalization + Total Debt’. In the absence of an equivalent ‘Market Capitalization’ estimate of a crown corporation such as BC Hydro, the term ‘Enterprise Value’ may be used to describe the “Book Value of Assets + Debt + Regulatory Account Balances”.

2.13.1 Does BC Hydro monitor and/or report a metric equal to or similar to ‘Enterprise Value’ (as defined by the formula above) as part of its financial or corporate performance metrics? If yes, please explain. If not, please provide names and descriptions of similar metrics being used.

RESPONSE:

BC Hydro does not monitor or report a metric similar to ‘Enterprise Value’ as defined in the preamble to the question. However, BC Hydro closely monitors its debt to equity ratio (net debt divided by total equity) as this metric is used by credit rating agencies to evaluate BC Hydro’s financial position.

13.0 References: Gjoshe IR 1.6.3, Gjoshe IR 1.17.1 and Gjoshe IR 1.17.2

2.13 The term 'Enterprise Value' is often used in financial performance as a measure of a publicly-listed company's total value, beyond market capitalization; and is estimated as 'Market Capitalization + Total Debt'. In the absence of an equivalent 'Market Capitalization' estimate of a crown corporation such as BC Hydro, the term 'Enterprise Value' may be used to describe the "Book Value of Assets + Debt + Regulatory Account Balances".

2.13.2 Would BC Hydro derive value from monitoring and reporting 'Enterprise Value per GWh of Domestic Load Served as part of its corporate or financial performance metrics?

RESPONSE:

As a Crown Corporation that is solely owned by the Government of B.C., "Enterprise Value per GWh of Domestic Load Served" as defined is not a measure from which BC Hydro would derive value. BC Hydro provides electricity to 95 per cent of British Columbia's population and so measuring its market value in the context of market capitalization would not provide any additional benefit.

Please refer to BC Hydro's Service Plan for a list of performance measures that BC Hydro uses to evaluate performance.

13.0 References: Gjoshe IR 1.6.3, Gjoshe IR 1.17.1 and Gjoshe IR 1.17.2

2.13 The term ‘Enterprise Value’ is often used in financial performance as a measure of a publicly-listed company’s total value, beyond market capitalization; and is estimated as ‘Market Capitalization + Total Debt’. In the absence of an equivalent ‘Market Capitalization’ estimate of a crown corporation such as BC Hydro, the term ‘Enterprise Value’ may be used to describe the “Book Value of Assets + Debt + Regulatory Account Balances”.

2.13.3 Please calculate the “Book Value of Assets + Debt + Regulatory Account Balances” as at the end of each fiscal year, over the F2002-F2021 period. Please use forecasts for F2020-2021.

RESPONSE:

The Book Value of Assets + Debt + Regulatory Account Balances as at the end of each fiscal year over the fiscal 2002 to fiscal 2021 period is shown in the table below. The financial information provided in this response has been updated based on information included in BC Hydro’s Evidentiary Update.

($ million)				
	A	**B**	**C**	**D = A+B+C**
Fiscal Year	**Book Value of Assets[1]**	**Debt[2]**	**Regulatory Account Balance**	**Total**
F2002 Actuals	**11,950**	**7,979**	**16**	**19,945**
F2003 Actuals	**11,822**	**7,890**	**102**	**19,814**
F2004 Actuals	**11,677**	**7,881**	**161**	**19,719**
F2005 Actuals	**11,785**	**7,612**	**182**	**19,579**
F2006 Actuals	**11,623**	**7,496**	**421**	**19,540**
F2007 Actuals	**11,987**	**7,657**	**445**	**20,089**
F2008 Actuals	**13,514**	**8,136**	**572**	**22,222**
F2009 Actuals	**14,969**	**9,440**	**1,018**	**25,427**
F2010 Actuals	**15,832**	**10,801**	**1,713**	**28,346**
F2011 Actuals	**17,043**	**11,644**	**2,160**	**30,847**
F2012 Actuals	**17,586**	**12,950**	**4,035**	**34,571**
F2013 Actuals	**19,041**	**14,134**	**4,434**	**37,609**

($ million)				
F2014 Actuals	**20,783**	**15,697**	**4,699**	**41,179**
F2015 Actuals	**22,039**	**16,876**	**5,434**	**44,349**
F2016 Actuals	**23,710**	**18,213**	**5,908**	**47,831**
F2017 Actuals	**25,761**	**20,024**	**5,597**	**51,382**
F2018 Actuals	**27,790**	**20,364**	**5,140**[3]	**53,294**
F2019 Actuals	**30,730**	**22,382**	**4,193**	**57,305**
F2020 Forecast	**33,234**	**23,728**	**4,486**	**61,448**
F2021 Forecast	**35,286**	**25,097**	**4,484**	**64,867**

1. **Book Value of Assets is calculated as total assets minus regulatory account assets, since the question asked that the Regulatory Account Balances be shown separately.**
2. **Debt includes the current and non-current portions of Long-Term Debt.**
3. **Amount reflects the adoption of International Financial Reporting Standards in BC Hydro's 2018/19 Annual Service Plan Report.**

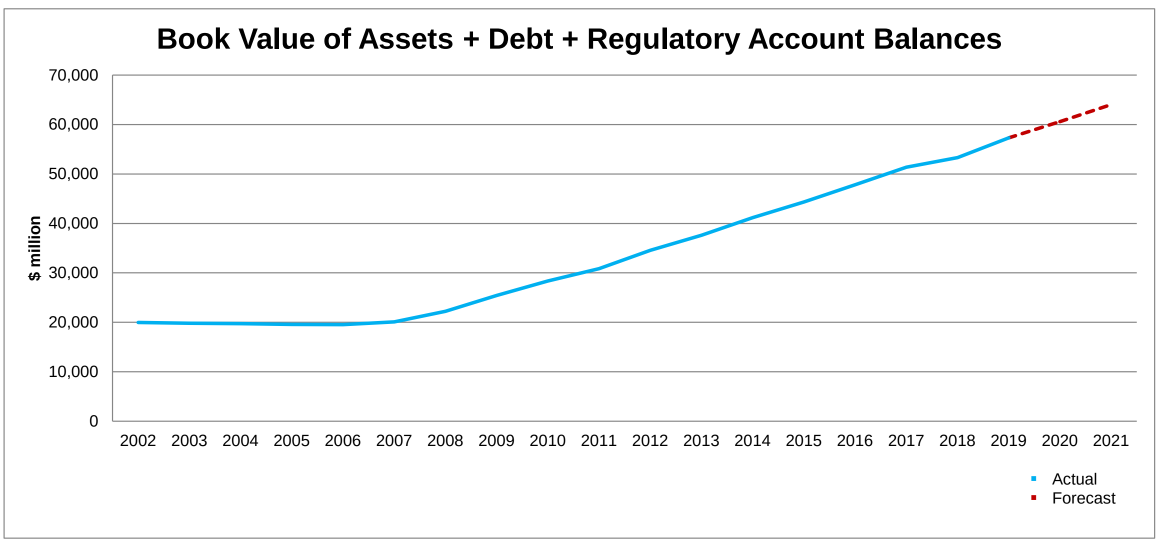
13.0 References: Gjoshe IR 1.6.3, Gjoshe IR 1.17.1 and Gjoshe IR 1.17.2

2.13 The term 'Enterprise Value' is often used in financial performance as a measure of a publicly-listed company's total value, beyond market capitalization; and is estimated as 'Market Capitalization + Total Debt'. In the absence of an equivalent 'Market Capitalization' estimate of a crown corporation such as BC Hydro, the term 'Enterprise Value' may be used to describe the "Book Value of Assets + Debt + Regulatory Account Balances".

2.13.4 Please provide a line graph of "Book Value of Assets + Debt + Regulatory Account Balances" for the F2002-F2021 period. Please use forecasts for F2020-F2021.

RESPONSE:

Please refer to BC Hydro's response to GJOSHE IR 2.13.3 for the data used to generate the line graph below.



13.0 References: Gjoshe IR 1.6.3, Gjoshe IR 1.17.1 and Gjoshe IR 1.17.2

2.13 The term 'Enterprise Value' is often used in financial performance as a measure of a publicly-listed company's total value, beyond market capitalization; and is estimated as 'Market Capitalization + Total Debt'. In the absence of an equivalent 'Market Capitalization' estimate of a crown corporation such as BC Hydro, the term 'Enterprise Value' may be used to describe the "Book Value of Assets + Debt + Regulatory Account Balances".

2.13.5 Please divide the "Book Value of Assets + Debt + Regulatory Account Balances" as at the end of each fiscal year over the F2002-F2021 period, by the GWh of provincial load served during that fiscal year. Please use forecasts for F2020-2021.

RESPONSE:

Please see the table below for the information requested in the question for the fiscal 2002 to fiscal 2021 period. The financial information provided in this response has been updated based on information included in BC Hydro's Evidentiary Update.

$ million, unless otherwise specified						
	A	B	C	D=A+B+C	E	F=D/E
Fiscal Year	Book Value of Assets[1]	Debt[2]	Regulatory Account Balance	Total	Provincial Load Served (GWh)[3]	Total/ Provincial Load Served
F2002 Actuals	11,950	7,979	16	19,945	47,485	0.42
F2003 Actuals	11,822	7,890	102	19,814	48,358	0.41
F2004 Actuals	11,677	7,881	161	19,719	49,830	0.40
F2005 Actuals	11,785	7,612	182	19,579	50,896	0.38
F2006 Actuals	11,623	7,496	421	19,540	52,118	0.37
F2007 Actuals	11,987	7,657	445	20,089	52,599	0.38
F2008 Actuals	13,514	8,136	572	22,222	52,987	0.42

$ million, unless otherwise specified						
F2009 Actuals	**14,969**	**9,440**	**1,018**	**25,427**	**52,008**	**0.49**
F2010 Actuals	**15,832**	**10,801**	**1,713**	**28,346**	**49,927**	**0.57**
F2011 Actuals	**17,043**	**11,644**	**2,160**	**30,847**	**50,290**	**0.61**
F2012 Actuals	**17,586**	**12,950**	**4,035**	**34,571**	**51,175**	**0.68**
F2013 Actuals	**19,041**	**14,134**	**4,434**	**37,609**	**50,681**	**0.74**
F2014 Actuals	**20,783**	**15,697**	**4,699**	**41,179**	**51,701**	**0.80**
F2015 Actuals	**22,039**	**16,876**	**5,434**	**44,349**	**50,892**	**0.87**
F2016 Actuals	**23,710**	**18,213**	**5,908**	**47,831**	**50,714**	**0.94**
F2017 Actuals	**25,761**	**20,024**	**5,597**	**51,382**	**51,576**	**1.00**
F2018 Actuals	**27,790**	**20,364**	**5,140**[4]	**53,294**	**51,789**	**1.03**
F2019 Actuals	**30,730**	**22,382**	**4,193**	**57,305**	**52,103**	**1.10**
F2020 Forecast	**33,234**	**23,728**	**4,486**	**61,448**	**52,984**	**1.16**
F2021 Forecast	**35,286**	**25,097**	**4,484**	**64,867**	**52,942**	**1.23**

1. **Book Value of Assets is calculated as total assets minus regulatory assets, since the question asked that the Regulatory Account Balances to be shown separately.**
2. **Debt includes both current and non-current portions of Long-Term Debt.**
3. **Provincial Load Served has been calculated as Domestic Energy less Seattle City Light less Tongass.**
4. **Amount reflects the adoption of International Financial Reporting Standards in BC Hydro's 2018/19 Annual Service Plan Report.**

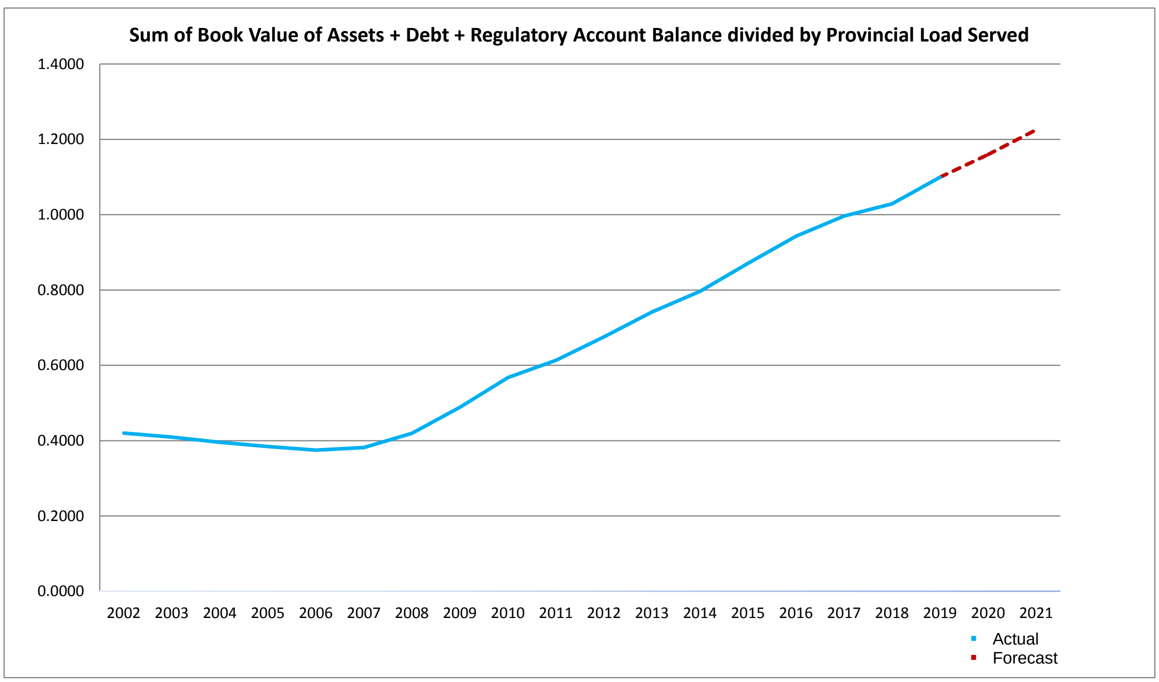
13.0 References: Gjoshe IR 1.6.3, Gjoshe IR 1.17.1 and Gjoshe IR 1.17.2

2.13 The term 'Enterprise Value' is often used in financial performance as a measure of a publicly-listed company's total value, beyond market capitalization; and is estimated as 'Market Capitalization + Total Debt'. In the absence of an equivalent 'Market Capitalization' estimate of a crown corporation such as BC Hydro, the term 'Enterprise Value' may be used to describe the "Book Value of Assets + Debt + Regulatory Account Balances".

2.13.6 Please provide a line graph of "Book Value of Assets + Debt + Regulatory Account Balances' divided by provincial load served (in GWh) during each fiscal year for the F2002-F2021 period. Please use forecasts for F2020-2021.

RESPONSE:

Please refer to BC Hydro's response to GJOSHE IR 2.13.5 for the data used to generate the line graph below.



14.0 Reference: BCUC IR 250.0; PRES Project

2.14.1 Further to BCUC IR 250.0, please explain whether BC Hydro keeps an inventory of other industrial activities of significant size, whether existing customers or potential new customers, which may benefit from BC Hydro electrification initiatives pursuant to section 4(2) of the Greenhouse Gas Reduction (Clean Energy) Regulation.

RESPONSE:

BC Hydro's Customer Service KBU engages with existing and potential new customers to identify an inventory of potential new or expanded customer electricity loads. BC Hydro then works with these customers to understand their projects and identify opportunities for electrification that may result in GHG reduction.

14.0 Reference: BCUC IR 250.0; PRES Project

2.14.2 Please provide a list of other potential regional transmission upgrade or extension projects, which BC Hydro may have identified or conducted planning studies for over the F2002-F2021 period, and which may warrant capital spending in similar fashion to the PRES project, whether in northeast BC or other regions.

RESPONSE:

There are three potential regional transmission upgrade projects which may warrant capital spending in a similar fashion to the PRES project, because they have been identified as supporting the B.C. Government's climate action strategies and CleanBC Plan,:

1. **Bear Mountain Terminal (BMT) To Dawson Creek (DAW) Transmission Voltage Conversion;**
2. **Prince George to Terrace Capacitors (PGTC); and**
3. **North Montney - Transmission Development.**

For project descriptions, please refer to BC Hydro's response to BCUC IRs 2.254.2 and 2.247.6.1.

14.0 Reference: BCUC IR 250.0; PRES Project

2.14.3 Please explain whether such regional projects, would serve to relieve existing transmission system bottlenecks; may provide benefits to a region in the form of a service upgrade from distribution to transmission voltage; or would represent a transmission extension into a presently un-served area.

RESPONSE:

The impact of each of the three regional projects described in BC Hydro's response to GJOSHE IR 2.14.2 is described below:

1. **The proposed Bear Mountain Terminal (BMT) To Dawson Creek (DAW) Transmission Voltage Conversion Project would relieve transmission system constraints and enable reliable electricity service to prospective new upstream natural gas processing customers in the Dawson Creek area.**

2. **The proposed Prince George to Terrace Capacitors (PGTC) Project would serve to increase the power transfer capability of the existing 500 kV transmission path from Prince George to Terrace to enable the electrification of prospective new LNG exporting terminal load(s) on the North Coast.**

3. **The proposed North Montney – Transmission Development Project would extend BC Hydro's 230 kV transmission system from either GM Shrum Generation Station or Southbank substation near Fort St. John into an area of the North Montney where there is presently no transmission service. This transmission system extension would enable the electrification of new upstream natural gas processing loads.**

14.0 Reference: BCUC IR 250.0; PRES Project

2.14.4 Please explain whether such regional projects have been identified pursuant to customer service inquiries, customer service requests or BC Hydro's planning initiatives.

RESPONSE:

The regional projects listed in BC Hydro's response to GJOSHE IR 2.14.2 were identified pursuant to a combination of customer service requests and BC Hydro planning initiatives based on customer service inquiries. Each of the proposed regional projects identified reflect the transmission system upgrade(s) that BC Hydro considers would be required to enable electricity service.

15.0 References: Gjoshe IR 1.2.3 and Gjoshe IR 1.9.1

2.15 Please provide in a Table format, the annual spend by Fiscal Year over the period F2002-F2021 for serving the non-integrated area of Ft. Nelson, itemizing an capturing the major cost items of a) Ft. Nelson Generation; b) AESO FTS (Ft. Nelson Area Transmission Service) cost; and where applicable cost of energy imports from Alberta.

RESPONSE:

The data requested for fiscal 2004 to fiscal 2019 is provided in Attachment 1 to this response. BC Hydro is unable to provide the data for fiscal 2002 and fiscal 2003 as the data is not easily accessible in our financial systems.

For fiscal 2020 and fiscal 2021, BC Hydro is redacting that information as it is confidential and pertains to our August 2019 Cost of Energy Evidentiary Update, in accordance with Order No. G-146-19. The un-redacted version of the response is being made available to the BCUC only.

Fort Nelson costs
F2004 to F2021
$million

	F2004 Actual	F2005 Actual	F2006 Actual	F2007 Actual	F2008 Actual	F2009 Actual	F2010 Actual	F2011 Actual	F2012 Actual	F2013 Actual	F2014 Actual	F2015 Actual	F2016 Actual	F2017 Actual	F2018 Actual	F2019 Actual	F2020 EU	F2021 EU
a) Fort Nelson Generation costs:																	[redacted]	[redacted]
Domestic gas purchases	10.2	11.6	15.6	11.3	11.5	15.9	7.2	6.5	3.7	2.6	8.4	6.8	3.1	1.2	1.1	1.4	[redacted]	[redacted]
Motor Fuel Tax	0.4	0.9	1.2	1.2	1.0	1.1	0.5	0.5	0.3	0.2	0.8	0.7	0.7	0.3	0.3	0.6	[redacted]	[redacted]
Carbon Tax	-	-	-	-	-	0.8	1.3	1.9	1.6	1.7	2.9	3.0	2.9	1.2	1.4	3.2	[redacted]	[redacted]
Other[1]	0.3	0.3	0.2	0.4	1.4	0.2	0.3	0.3	0.4	0.2	0.4	0.3	0.4	0.3	0.1	0.4	[redacted]	[redacted]
	10.8	**12.8**	**17.0**	**12.9**	**13.9**	**18.1**	**9.4**	**9.2**	**6.0**	**4.7**	**12.5**	**10.7**	**7.1**	**2.9**	**3.0**	**5.6**	[redacted]	[redacted]
b) AESO FTS costs	**0.2**	**0.2**	**0.3**	**0.5**	**0.4**	**0.7**	**0.7**	**0.5**	**1.0**	**1.2**	**1.3**	**0.8**	**1.2**	**2.9**	**3.1**	**1.6**	[redacted]	[redacted]
c) Cost of energy imports from Alberta	**8.2**	**10.3**	**12.7**	**9.7**	**10.9**	**8.3**	**5.5**	**4.7**	**2.5**	**2.1**	**2.7**	**1.4**	**1.3**	**0.3**	**0.9**	**17.7**	[redacted]	[redacted]
Total	**19.2**	**23.2**	**30.0**	**23.1**	**25.2**	**27.1**	**15.6**	**14.4**	**9.5**	**7.9**	**16.5**	**13.0**	**9.6**	**6.1**	**6.9**	**24.8**	[redacted]	[redacted]

[1] *includes transportation costs, water consumption costs and chemical costs.*

16.0 Reference: Gjoshe IR 1.14.2

2.16.1 Please provide in a table format BC Hydro's annual sustainment capital spending for the period F2002-F2021, using forecasts for fiscal years F2019-F2021.

RESPONSE:

BC Hydro's annual sustaining capital expenditures from fiscal 2002 to fiscal 2021 are provided in the table below.

($ millions)	
Fiscal Year Actuals	**Sustaining Capital Expenditures**
2002	333
2003	367
2004	375
2005	331
2006	363
2007	428
2008	557
2009	664
2010	948
2011	865
2012	956
2013	1,009
2014	979
2015	1,005
2016	1,136
2017	1,286
2018	1,190
2019	965
2020 Plan	978
2021 Plan	1,093

The information above is from BC Hydro's published Annual Reports and includes sustaining capital expenditures for subsidiaries Powerex and Powertech, which is not material to the overall totals.

16.0 Reference: Gjoshe IR 1.14.2

2.16.2 Please provide a comparison of DSM spend and sustainment capital spending over the period F2002-F2021, using forecasts for fiscal years F2019-F2021. Please discuss any trends or findings therein.

RESPONSE:

The table below shows sustaining capital expenditures and DSM program expenditures from fiscal 2002 to fiscal 2021. Fiscal 2019 values have been updated to reflect actuals, and TMP program expenditures in fiscal 2021 have been removed from the DSM forecast in accordance with BC Hydro's Evidentiary Update.

($ million)		
Fiscal Year Actuals	Sustaining Capital Expenditures	Total DSM Program Expenditures
2002	333	11
2003	367	31
2004	375	43
2005	331	40
2006	363	30
2007	428	26
2008	557	41
2009	664	66
2010	948	97
2011	865	96
2012	956	147
2013	1,009	121
2014	979	96
2015	1,005	97
2016	1,136	114
2017	1,158	70
2018	1,190	57
2019	965	80
2020 Plan	978	64
2021 Plan	1,093	64

The drivers of sustaining capital expenditures and DSM expenditures over this timeframe are different. As such, comparing trends is not meaningful.

Sustaining capital expenditures over this timeframe address reliability, asset condition, regulatory, safety, security and environmental risks, issues and opportunities associated with existing assets.

DSM activity over most of this timeframe was focused primarily on helping to meet the resource needs at the system level. The level of DSM expenditures was also informed by savings targets within the *Clean Energy Act* and adequacy and cost-effectiveness requirements under the DSM Regulation. In recent years, DSM expenditures have been moderated as a result of the on-going energy surplus.

David Ince Information Request No. **2.1.0** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

Topic: **Performance Metrics**

Reference: **Appendix E: Service Plan. Page 17 of 36.**
Ince IR 1.1.1

The response to Ince 1.1.1 states: "The BC Hydro system is highly complex and dynamic and it is difficult to make a direct link between the SAIDI, SAIFI and Generation Facility Forced Outage Factor performance metrics and investments in the system. These metrics are influenced by factors beyond capital and maintenance investment including operational procedures and uncontrollable events".

2.1.0 Please confirm that BC Hydro has established some degree of positive correlation between sustaining capital and operations expenditures, and all of the performance metrics indicated above.

RESPONSE:

Confirmed. In addition to meeting safety, regulatory and environmental requirements, the objective of BC Hydro's capital and maintenance investment strategies is to manage risk and achieve the target levels of system performance for SAIDI, SAIFI and the Generation Forced Outage Factor. BC Hydro has established some degree of positive correlation between sustaining capital and these performance metrics for specific investments within the portfolio.

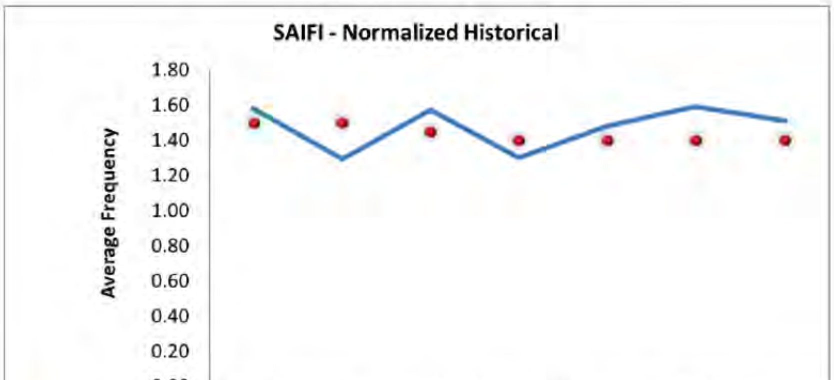
However, even for targeted investments, the correlation between reliability project investments and direct quantified reliability improvements is imprecise due to timing lags, uncontrollable events, operational practices, and other system changes or issues that may mask the benefits associated with the investment.

Attachment 1 to this response provides BC Hydro's response to CEC IR 2.5.1.1. from the Capital Expenditures and Projects Review proceeding where we provide further discussion on how these factors make it difficult to quantify the positive correlation between investment and customer reliability.

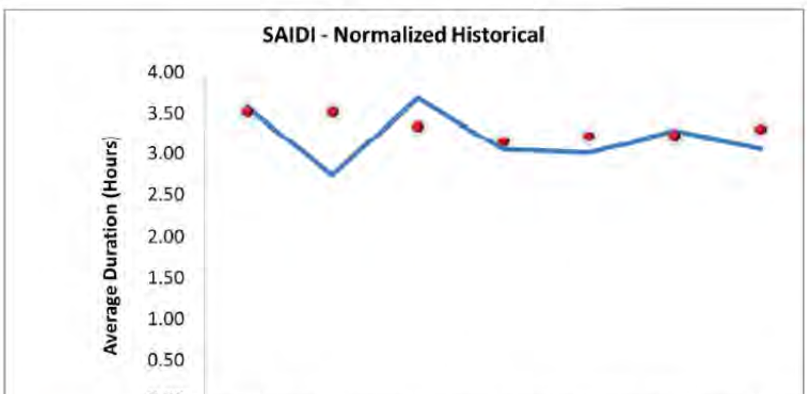
Commercial Energy Consumers Association of British Columbia Information Request No. **2.5.1.1** Dated: **June 6, 2019** British Columbia Hydro & Power Authority Response issued **July 4, 2019**	Page 1 of 3
British Columbia Hydro & Power Authority **Review of the Regulatory Oversight of Capital Expenditures and Projects**	**Exhibit: B-16**

5.0 Reference: Exhibit B-15, pages 12-13

Figure 3 SAIFI and SAIDI – Normalized Historical Measures



	2012	2013	2014	2015	2016	2017	2018
Historical SAIFI	1.58	1.29	1.57	1.30	1.48	1.59	1.51
Historical Targets	1.50	1.50	1.45	1.40	1.40	1.40	1.40



	2012	2013	2014	2015	2016	2017	2018
Historical SAIDI	3.59	2.73	3.69	3.06	3.01	3.28	3.07
Historical Targets	3.52	3.52	3.34	3.15	3.22	3.22	3.30

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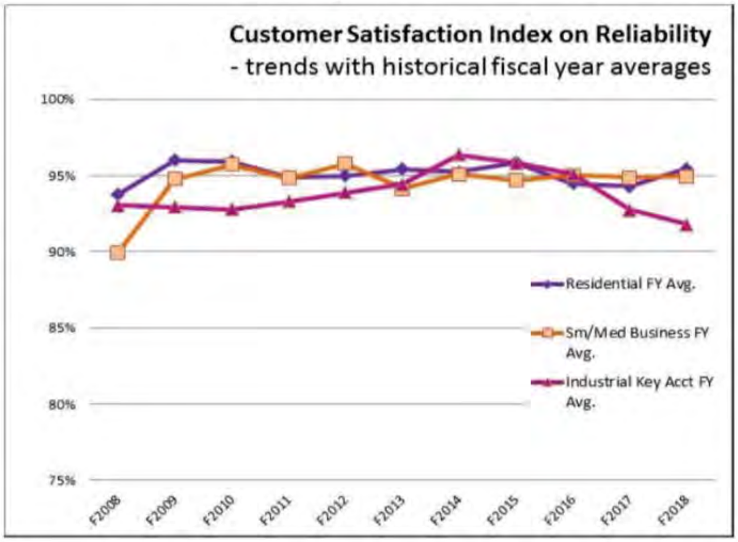
British Columbia Hydro & Power Authority **Review of the Regulatory Oversight of Capital Expenditures and Projects**	**Exhibit: B-16**

Figure 4 Customer Satisfaction Index on Reliability



2.5.1 Does BC Hydro experience diminishing returns for the incremental spending it now takes in improving SAIDI and SAIFI or the Customer Satisfaction Index on Reliability?

2.5.1.1 If yes, is BC Hydro able to provide quantification of improvements directed at making these improvements?

RESPONSE:

The quantification of reliability improvements for reliability focussed investments on individual distribution feeders includes initial estimates of expected reliability improvements, general project type based improvement benefits, and reliability reporting aggregated at the feeder, district, area, and system level.

Quantification of performance improvements associated directly with a specific improvement project can, and often does, have a delay before the performance improvements are seen in the reported feeder reliability metrics or they can be masked or negated by other issues that arose for which the improvement was not intended. This makes it imprecise to correlate reliability project investments directly to quantified reliability benefits. For example:

- **A targeted feeder improvement in a specific year (e.g., fiscal 2018) might not get built until the end of the fiscal year, resulting in any realized reliability improvements to show up the following year;**

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- **If the improvement project is addressing a specific issue (e.g. severe weather related outages) and the current or following year is not impacted by those specific issues (e.g., it is a 'good' weather year) the benefit of the investment may not be evident until the specific issue (e.g. severe weather) occurs again;**
- **If the circuit experiences other issues (e.g., vegetation) not directly addressed by the improvement, the target performance improvement will be diluted or masked; and**
- **Most other system changes and growth related projects on the target circuits, or related neighbouring circuits, will also impact/mask the direct benefits from the specific reliability project related performance indices.**

Quantification of reliability improvements for larger reliability programs with multiple installations is done on a manual, as-needed basis to show overall program delivered benefits.

David Ince Information Request No. **2.2.0** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit:** **B-13**

Topic: **Performance Metrics**

Reference: **Appendix E: Service Plan. Page 17 of 36.**
Ince IR 1.1.1

The response to Ince 1.1.1 states: "The BC Hydro system is highly complex and dynamic and it is difficult to make a direct link between the SAIDI, SAIFI and Generation Facility Forced Outage Factor performance metrics and investments in the system. These metrics are influenced by factors beyond capital and maintenance investment including operational procedures and uncontrollable events".

2.2.0 Given the persistent constraints of capital and operations funding, please indicate if BC Hydro is attempting to further quantify and then implement a suitable level of sustaining capital and operations expenditures to realize an optimum balance of cost, reliability and customer satisfaction.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.43.4 where we explain how the annual enterprise capital planning process and continuous improvement efforts show that BC Hydro continues to move the capital investment portfolio towards an optimal level by balancing affordability, system performance and risk.

Please also refer to BC Hydro's response to BCOAPO IR 1.43.2 and to section 5.8 of Chapter 5 of the Application for a detailed description of BC Hydro's approach to maintenance planning, including determining the appropriate maintenance investment levels through the consideration of many factors.

David Ince Information Request No. **2.3.0** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

Topic: **Performance Metrics**

Reference: **Appendix E: Service Plan. Page 17 of 36.**
Ince IR 1.1.1

The response to Ince 1.1.1 states: “The BC Hydro system is highly complex and dynamic and it is difficult to make a direct link between the SAIDI, SAIFI and Generation Facility Forced Outage Factor performance metrics and investmens in the system. These metrics are influenced by factors beyond capital and maintenance investment including operational procedures and uncontrollable events”.

2.3.0 Has BC Hydro at a high level sponsored or accessed external studies that attempt to quantify the tradeoffs between cost, reliability and customer satisfaction?

RESPONSE:

In 2009, BC Hydro sponsored UMS Group Inc. to analyze the effects of capital investments and operation and maintenance spending on system reliability, resulted in a final report. The final report was made available in Exhibit B-1 of the Fiscal 2011 Revenue Requirements Application proceeding “Link between Spending and Reliability”, section 1.2 “External Review to Establish the Performance/Investment Linkage”. A copy of the final report is provided as Attachment 1 to this response. The analysis was based on reported financial results of 188 utilities and overall reliability from the Institute of Electrical and Electronics Engineers (IEEE) 2007 survey. It concluded that:

1. **Aging distribution infrastructure constraints will eventually negate reliability improvement;**
2. **Levels of capital investment and operation and maintenance spending can be directional but not precise in predicting the impact on reliability; and**
3. **The following investments/spending are effective proxies for predicting changes in reliability, assuming no major change in weather patterns:**
   - **Circuit protection (sectionalizing with reclosers and fuses);**
   - **Enhanced tree trimming (optimizing tree trimming cycles and removal of “danger” trees); and**
   - **Repair/replacement of poles and pole top equipment vulnerable to electrical faults resulting in system outages.**

UMS group

Americas

Asia Pacific

Europe

Mideast/Africa

Effects of Capital Investments and O&M Spending on System Reliability

Final Report

November 2009

BC hydro

UMS Group | Asset Optimization

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Contents

Executive Summary

UMS Group set forth to prove or disprove the hypothesis that overall system reliability performance can be predicted as a direct result of capital investment and/or O&M spending levels. To accomplish this, we conducted analyses from a number of dimensions, namely we:

- Determined the industry norms related to capital investment and O&M spending levels (based on the reported financial results of 118 utilities) and overall reliability (applying the results of the IEEE 2007 survey).
- Explored potential correlations (applying basic regression analysis techniques) between capital investment and/or O&M spending levels and overall system reliability (based on reported financial results and reliability performance of the selected group of 43 comparative utilities, selected based on noted similarities with BC Hydro or their industry reputation as leaders in the area of distribution reliability).
- Conducted an in-depth review of 8 utilities to build upon the higher level insights of the analyses summarized above, and develop a methodology to predict changes in reliability based on investment and spending levels.

In analyzing the results, a number of insights and conclusions can be drawn:

Aging Distribution Infrastructure constrains (and will eventually negate) reliability improvement

Though overall capital investment and O&M spending have increased at rates commensurate to inflation (CAGR of 6.5 and 4.4 respectively), the actual level of spending for 70 percent of the 118 utilities surveyed is not adequate to sustain acceptable performance over the long haul. Eventually, well-targeted reliability-related investments and spending, aimed at mitigating and/or reducing customer interruptions (e.g. sectionalizing, enhanced tree trimming, and lightning protection) will not be able to offset the impact of the gradual deterioration of an aging electric distribution infrastructure.

- The impact of functioning yet technically and economically obsolete assets will eventually overtake the effects of well-targeted reliability programs (utilities generally accept the notion that the absence of targeted reliability investments/spending, will increase customer interruptions annually in the range of 3 to 5 percent), and
- Targeted reliability programs will begin to reach a point of diminishing returns (e.g. we will reach a point where the tree trimming cycle is optimized and danger trees are removed, circuit protection is fully implemented, and service restoration measures-directional fault indicators, etc. are maximally deployed). At that point, the gradual rate of deterioration of 3 to 5 percent will become the controlling variable.

However in the foreseeable future (next 5 years), there are sufficient opportunities for BC Hydro to achieve improved average system reliability without changing the planning and budgeting framework, but to do so will require a consistent level of targeted reliability spending relating to the avoidance of greater than 170,000 customer interruptions annually; and to the extent that capital investment exceeds FY2009 actual spending levels, the accumulating tide of issues related to aging infrastructure will be stemmed.

Executive Summary *(Continued)*

Levels of capital investment and O&M spending can be Directional (but not precise) in predicting impact on reliability

In attempting to find a correlation between levels of capital investment/O&M spending and reliability performance over a 3-year period, one can see a trend forming when comparing the level of or change in investment and spending levels, but only with SAIFI and after imposing a 2 to 3 year lag. In fact:

- Changes in capital investment and/or O&M spending up to 20 percent show a tight correlation with steady improvement (decrease) in SAIFI as investment/spending levels increase or a deterioration of SAIFI (increase) as investment/spending levels decrease.

- Though the impact on SAIFI is steady, it is not dramatic. This is due to the dispersion of available funds to programs and projects not directly tied to reliability; and for the sake of this analysis, an underlying assumption that any increase in funding will maintain the same percentages with respect to reliability vs. non-reliability programs and projects.

- In both the capital investment and O&M spending scenarios the change in SAIFI (percent increase or decrease) is more dramatic when decreasing the investment/spending levels by more than 50 percent than when increasing the level of investment by more than 50 percent. A possible explanation is the offset of gradual annual deterioration of SAIFI that distribution systems typically experience due to the advancing age and condition of its assets.

We term this correlation as “Directional” since the spread of outcomes of this higher level analysis (particularly outside a change of greater than 20 percent) is too wide to apply predictive formulae to calculate anticipated improvement (or degradation) in reliability performance:

- Capital Investment and O&M Spending budgets include a myriad projects and programs, many of which have little, if any impact on improving reliability (e.g. long-term programs geared at the electric distribution infrastructure will stem the overall degradation of the system, but will not necessarily manifest itself as avoided customer interruptions). Likewise, new connections, though recovered in rates, reflect as part of the capital budget, but clearly are not driven by reliability but rather under an “obligation to serve” mandate. And, investments related to energy efficiency or tied to meeting future capacity requirements have a loose, if any tie to reliability.

- Well-targeted reliability investments and spending, unless done in a comprehensive and compressed manner (particularly those geared towards mitigation rather than elimination of customer interruptions), can only have an impact if an event occurs on the specific circuit or substation.

- Weather is another variable that impacts reported reliability as the storm exclusion criteria varies across the states and provinces in North America; and as utilities invest in projects and programs that storm harden their systems there will invariably be perturbations as previously unreported customer interruptions become reportable.

Executive Summary *(Continued)*

Well-Targeted Investments/Spending will yield predictable results

Having established that (1) the level of capital investment/O&M spending will, over the long haul, impact a utility's ability to sustain acceptable reliability; and (2) there is a "directional" if not precise relationship between the two when viewed at a high level, the study shifted to analyzing that portion of the capital investment budget (and to a lesser extent O&M spending budget) that represents reliability programs and projects.

Predicated on the following:

- Establishing initiatives and actions with a bias towards storm hardening and sectionalizing the feeder backbone and other worst performing circuits;
- Allocating 20 to 30 percent of the capital investment budget to reliability-related projects; and
- Maintaining a consistent and persistent focus on reliability on a year-to-year basis (i.e. avoid the one-year "blip" syndrome)

We did discover a number of keys that can be used to justify investments and, more relevant to this effort, predict improvement in the form of avoided customer interruptions. There are a full range of reliability-related initiatives and actions that are necessary to improve or as a minimum maintain reliability. Our experience, substantiated by discussions with the previously described group of 8 utilities (identified in the Overall Approach section of this report), points to a handful of projects and programs that are viewed as effective proxies for predicting changes in reliability; namely:

- Circuit Protection (sectionalizing with reclosers and fuses)
- Enhanced Tree Trimming (optimizing tree trimming cycles and removal of "danger" trees)
- Repair/replacement of Pole and Pole Top Fault Causing Equipment

By assigning a cost of an avoided interruption to these projects and programs, we were able to deduce the number of avoided customer interruptions on a per investment basis, aggregate them and apply the 5 percent system degradation offset factor, and then calculate a predicted impact to overall SAIFI. The anomaly of weather still prevails, but the approach has been validated at 3 separate utilities and accepted by their regulators as an appropriate methodology for justifying investments and establishing system performance expectations.

The following table provides an encapsulated view of this approach and is accompanied by a sample calculation to illustrate its application.

Summary of Cost Per Avoided Interruption
(By Project/Program Category)

(Note that all costs in this report are in Canadian Dollars)

Project/Program	Cost per Avoided Interruption	Comments
Circuit Protection	\$100	Ranges from \$13 to \$400 based on experienced outages per year and CIs per outage (table provided in Qualitative Review section)
Enhanced Tree Trimming	\$80	\$40 for problematic circuits and \$120 for less problematic circuits
Repair/Replace Pole and Pole Top Fault Causing Equipment	\$75	

Sample Calculation: For purpose of illustration we will assume that the \$27 million assigned to protection improvements in the FY2010 budget fit the criteria outlined above. Using a \$100 cost per avoided interruption factor, the effect of these investments would be to decrease customer interruptions by approximately 273,000. Applying the 3 to 5 percent overall system degradation factor as an offset results in a net avoidance of 103,000 to 170,000 customer interruptions or a corresponding improvement in SAIFI of 0.06 to 0.10.

This calculation assumes no major change in weather patterns. Should BC Hydro experience a significant increase or decrease in severe storms, an explanation of variance relative to weather will be required.

Executive Summary *(Continued)*

BC Hydro's Reliability Performance (as measured by SAIFI) is predictable given the aforementioned insights and conclusions

BC Hydro's capital investment levels between FY2006 and FY2008 were well below industry norms, with an overall decline in FY2009 SAIFI to 1.67 (from 1.33 in FY2007). Stemming this trend will require sustained capital investment levels in the range budgeted for FY2010, applying the following well-targeted two-pronged approach:

- Investments necessary to support current customer-centric strategy
- Circuit protection and enhanced tree trimming on the distribution feeder backbone and other worst performing circuits

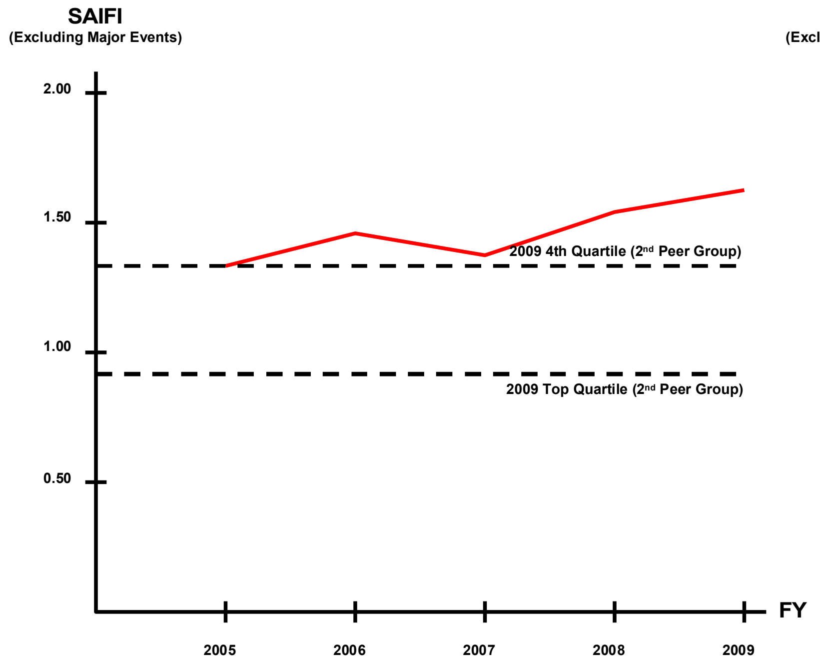
Maintaining this focus for three years will likely return SAIFI to levels commensurate to FY2007, without detracting from current customer satisfaction ratings.

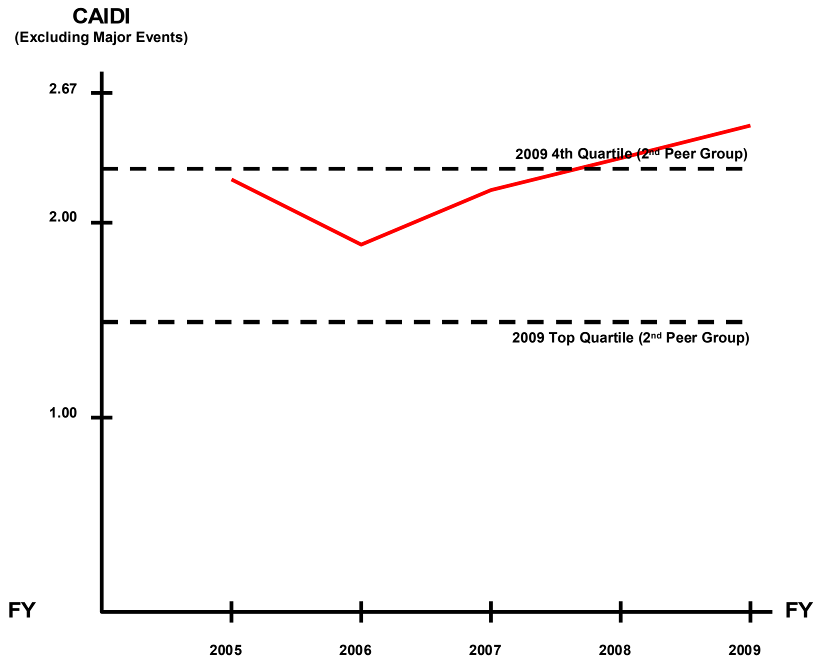
Contents

- **Executive Summary**
- **Context of the Analysis**
- **Overall Approach**
- **Overall Industry Comparison**
- **Spending – Reliability Comparisons**
- **Qualitative Review**

Context of the Analyses

It is one of BC Hydro's stated priorities to "lead other companies in providing extraordinary value to its customers." Of course, accomplishing this goal is inextricably linked to providing safe and reliable service, the absence of which will most assuredly lead to poor ratings in this key performance measure. In fact, BC Hydro has received identically high customer service ratings in both FY2008 and FY2009 (90 percent against a target of 80 percent); and this despite a fairly steady decline in overall system reliability (as measured by SAIFI and CAIDI):





This apparent dichotomy (high customer satisfaction amidst declining reliability) can be explained on two fronts:

- SAIFI and CAIDI, by their very nature reflect system averages. Though specific targeted capital investments (and to a lesser extent O&M programs) can result in immediate improvement to SAIFI and CAIDI, their impact is most significantly realized over an extended period of time.
- BC Hydro has consciously embarked on a customer-centric program to match well-targeted investments and spending at levels commensurate to specific customer needs and expectations re: level of service and response. Therefore, despite the negative trend in overall system reliability (and relatively low performance-4th quartile for both measures), BC Hydro has been effective in segmenting its customer base and meeting the specified needs and expectations.

Context of the Analyses *(Continued)*

So, the obvious question is "Why embark on this analysis?" or more specifically, "Why should BC Hydro be concerned about SAIFI or CAIDI?" It appears as if the customer-centric plan is working and that the reporting of system averages is potentially misleading. In fact, most industry experts will acknowledge that SAIFI and CAIDI do not tell the entire story; yet many view these measures as part of the story. A continually deteriorating electric distribution infrastructure will, over time, trump well-targeted capital investments and O&M spending: The impact of increased equipment failures and/or weather-related events will more than counter-balance the benefits of specific reliability projects and programs.

With that in mind, UMS Group applied benchmarking and comparative diagnostics to ascertain the extent of any relationship that might exist between investment/spending and reliability (both from an overall industry and BC Hydro perspective); not to conduct measurable comparisons of BC Hydro's investment/spending levels relative to these variables, and certainly not to address any apparent gaps in performance or suggest a plan to improve performance (particularly given their strong customer satisfaction ratings); but rather to validate the existence of any interrelationships among these variables.

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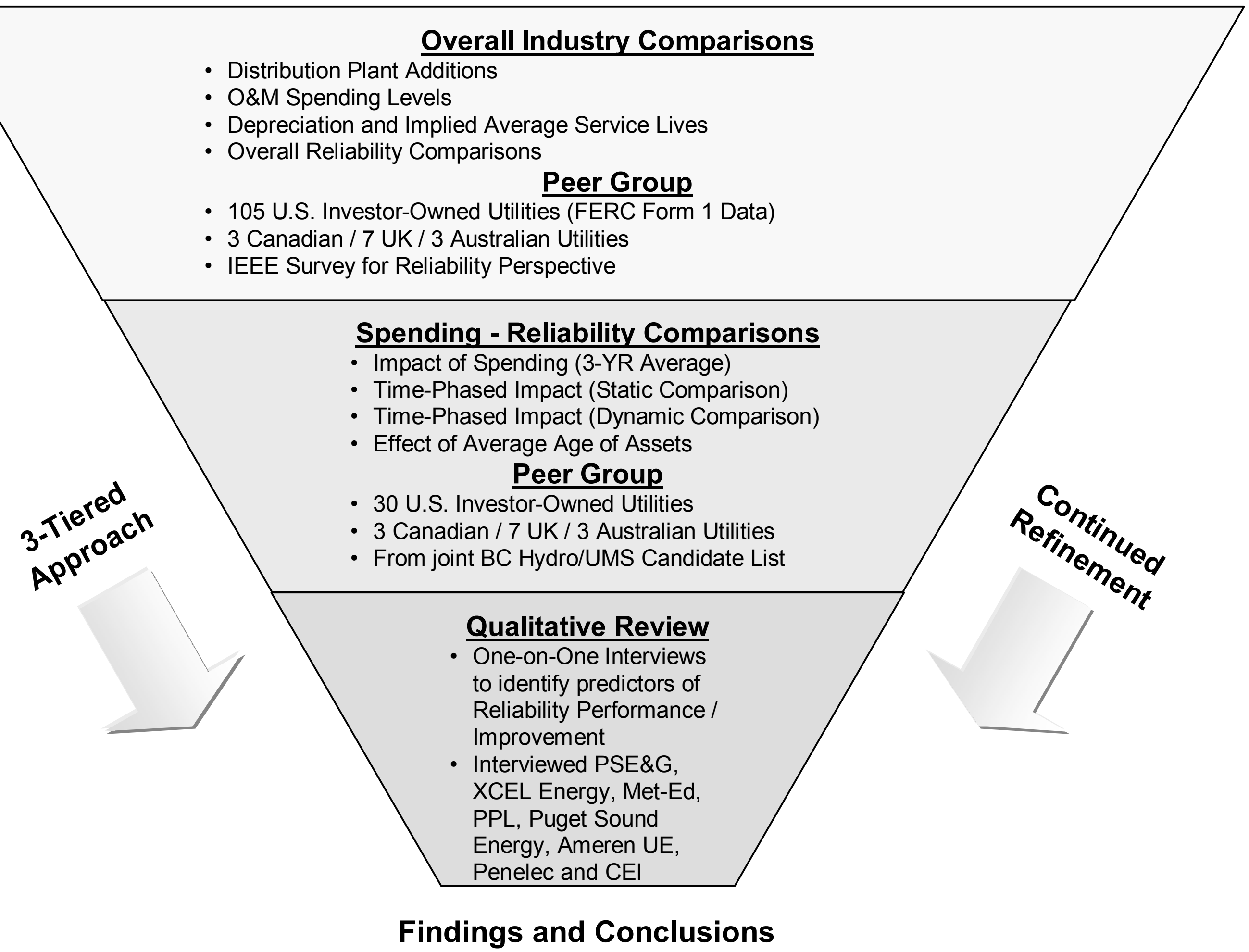
- Executive Summary
- Context of the Analysis
- Overall Approach
- Overall Industry Comparison
- Spending – Reliability Comparisons
- Qualitative Review

Overall Approach

UMS Group applied a 3-tiered approach in assessing the possible correlation between capital investment and/or operating and maintenance spending and overall system reliability. Embedded in this approach was the establishment of two peer groups: One representing 118 utilities to support high level financial and reliability comparisons, and a subset of that group (43 utilities) to focus directly on any correlation that might exist between investment/spending levels and overall system reliability. Recognizing that these analyses (and any correlations) will provide insights, but may not be sufficient in arriving at definitive results, we approached 8 of the second tiered utilities to identify specific criteria to assist BC Hydro in predicting the impact of future investments/spending on reliability.



Overall Approach *(Continued)*

Consistent with the aforementioned 3-tiered approach, UMS Group formed 2 peer groups: The first group was used to establish a context around and gain insights on the varying levels of investment and spending during the 2005 to 2009 time frame; and the second group explored potential relationships between investment and spending levels and reliability. We then selected a subset of this second group to conduct interviews to further refine and expand upon previous observations.

- The first peer group consisted of all U.S. utilities with more than 100,000 customers that filed FERC Form 1 financial information during the years 2005 through 2008; as well as 13 selected utilities from Canada, the UK and Australia.
- The second peer group was a subset of this initial list of target utilities, selected based on noted similarities with BC Hydro or on their industry reputations as leaders in the area of distribution reliability. The utilities that comprised this peer group are listed below (highlighted in blue are the utilities with whom interviews were conducted):

Pennsylvania Electric Co. (Penelec)	AEP-Ohio Power Co.	Energy Australia (Sydney)
Metropolitan Edison Co. (Met-Ed)	AEP-Columbus Southern Power Co.	ETSA (Adelaide)
Pennsylvania Power Co.	Duke Energy Ohio	Energex (Brisbane)
Cleveland Electric Illuminating Co. (CEI)	Center Point Energy	CE Electric UK-YEDL
Ohio Edison Co.	Oncor Electric Delivery	CE Electric UK-NEDL
Toledo Edison Co.	**Ameren UE**	SSEPD (Southern Electric Power)
Duquesne Light Co.	Pacific Gas & Electric Co.	SSEPD (Scottish Electric Power)
PECO Energy Co.	San Diego Gas & Electric Co.	Electric Northwest Limited
Commonwealth Edison Co.	**Puget Sound Energy Inc.**	Western Power Dist. South West
PPL Electric Utilities Corp.	Progress Energy Florida	Western Power Dist. South Wales
Public Service Electric & Gas	Niagara Mohawk Power Corp.	Hydro Quebec
Wisconsin Electric Power Co.	New York State Electric $ Gas	Hydro One
Wisconsin Power and Light Co.	Baltimore Gas & Electric	BC Hydro
Northern States Power Co. (XCEL)	Arizona Public Service Co.	
Public Service Co. of Col. (XCEL)	Virginia Electric & Power Co,	

Overall Approach *(Continued)*

In acknowledgement of the inherent difficulty in proving a potentially null hypothesis (that there may in fact be no relationship between investment and spending levels and overall system reliability), UMS Group opted to use the aforementioned 3-tiered approach to, in effect, minimize the probability of leaving a stone unturned. We strove to not only answer the question from 3 different perspectives, but to present a broader context by integrating these perspectives into a common view.

TIER 1 Overall Industry Comparisons	TIER 2 Spending – Reliability Comparisons	TIER 3 Qualitative Review
Activities		
Established High and Low Quartiles for key financial indicators (e.g. Capital Investment or Net Plant Additions, O&M Spending, Depreciation and corresponding Implied Average Service Life Performed a High Level Comparison of BC Hydro against the above mentioned key financial indicators Performed a High Level Comparison of BC Hydro Reliability with IEEE 2007 Survey and Performance of Tier 2 Peer Group	Whereas Phase 1 looked globally across 118 electric utilities and established an overall context for the analyses, this tier of our analysis investigated potential relationships between investment and spending levels and reliability with a narrower group of utilities (total of 43) Looked for correlations from both a static and dynamic perspective (where the static view looked at the impact of spending level on actual reliability performance and the dynamic view looked at the extent to which changes in spending levels caused a change in reliability).	Conducted targeted interviews with 8 utilities based on system demographics and/or reputation for improved reliability Applied insights gleaned from recently conducted interviews and reliability assessments conducted over the past 3 years to provide a more definitive roadmap (through practices and programs) to predict the impact of investments and spending on reliability
Outcomes		
From a high-level view, grounded the subsequent analysis with respect to investment and spending levels across the industry with an eye towards assessing the adequacy of BC Hydro's investment and spending levels and gaining insights on the past 3-year trend in reliability performance.	Identified the extent of any correlation between investment and spending levels and reliability	Identified parameters and approaches to better predict the impact of investment and spending on overall system reliability (as represented by SAIFI and CAIDI)

Contents

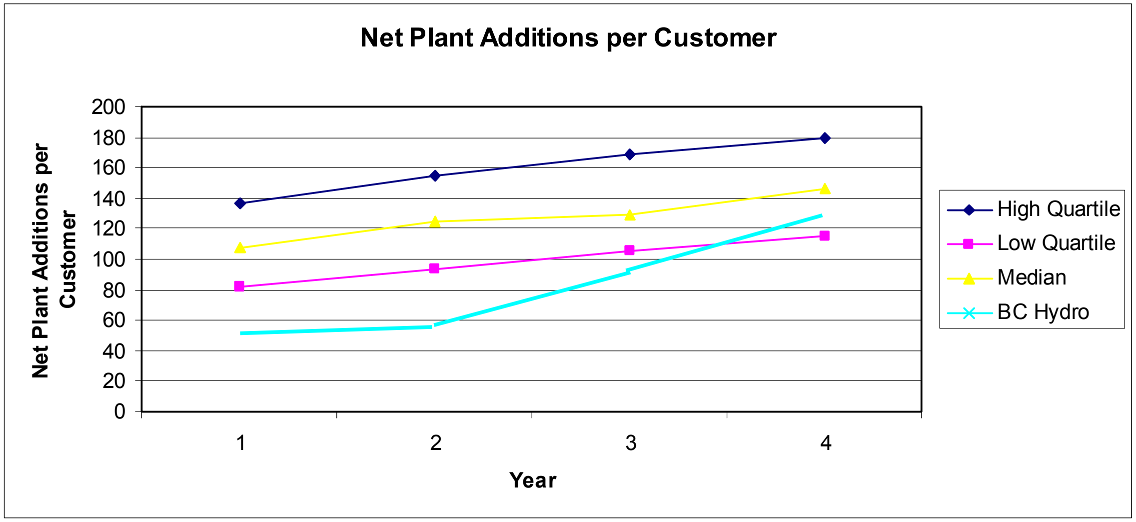
Overall Industry Comparisons

In establishing an initial framework for our analyses, UMS Group reviewed FERC Form 1 data of 105 U.S. Investor-Owned Utilities and annual reports from a representation of Australian, the UK and Canadian utilities to provide a high level view of:

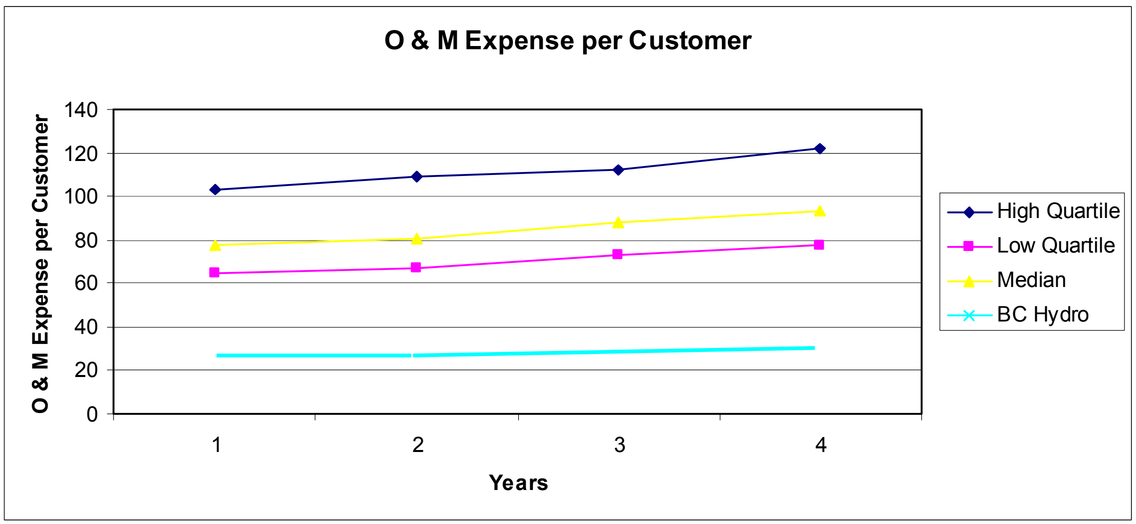
- Capital Investment (Net Plant Additions) and O&M Spending Trends on a per customer basis, identifying industry high and low quartiles as well as median investment/spending levels. This allowed for the comparison of BC Hydro's investment/spending levels with 118 other utilities and served to validate any linkage we might suggest between investment and spending levels and reliability performance.
- Depreciation as a percentage of Net Plant (again in terms of industry high and low quartiles and median) which translated to similar comparisons of the Implied Average Service Life (ASL) of the distribution assets.
- The ratio of Net Plant Additions to Depreciation indicated the adequacy of current investment levels to offset the deterioration of distribution assets due to aging. Applying the thumb rule that a ratio of 2.0 to2.4 represents the amount to keep ahead of the impacts of aging infrastructure; and that any ratio greater than 1.0 indicates the need for a rate reset (or in the absence of a rate reset indicates "over-investment" in the system), we were able to glean the extent to which the industry's electric distribution infrastructure is aging (which has a corresponding impact on a utility's ability to sustain high reliability).

Rounding out this phase of the analysis, UMS Group reviewed the 2007 IEEE Survey, setting the stage for initial insights regarding a potential link between investment/spending and reliability.

Overall Industry Comparisons *(Continued)*



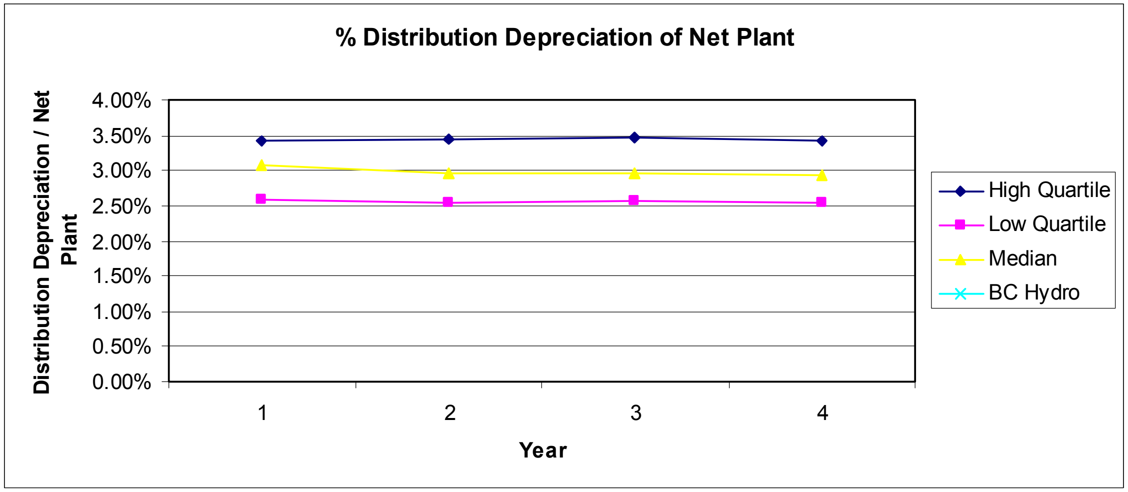
For the 118 participants that comprised the initial peer group, Net Plant Additions (less New Connections) increased at a CAGR of 6.5 percent over the past 4 years (Until recently BC Hydro has been investing at levels considerably lower than the industry norms; recent trends indicate that BC Hydro will be investing at levels approaching the median investment level of these utilities).

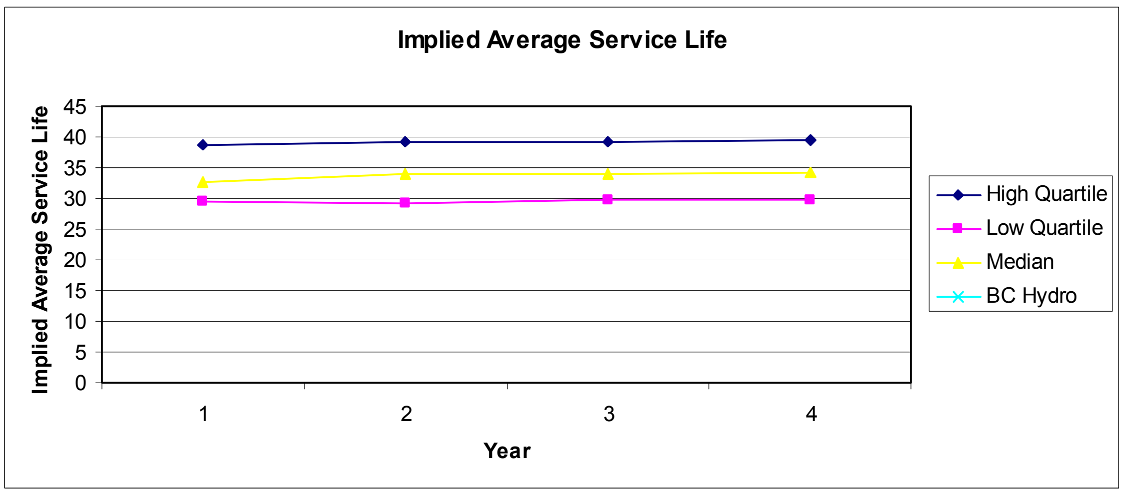


Similarly, O&M Spending experienced an increase, but at a lower CAGR of 4.4 percent over this same 4-year time period. And, though BC Hydro may have experienced some growth in O&M spending, its actual level of O&M spending is well below the industry norms.

Overall Industry Comparisons *(Continued)*

Depreciation for the comparison panel as a percent of Net Plant is consistent over the 4-year analysis period (median of 3 percent); implying average service lives of distribution assets between 30 and 40 years (2nd and 3rd quartiles).

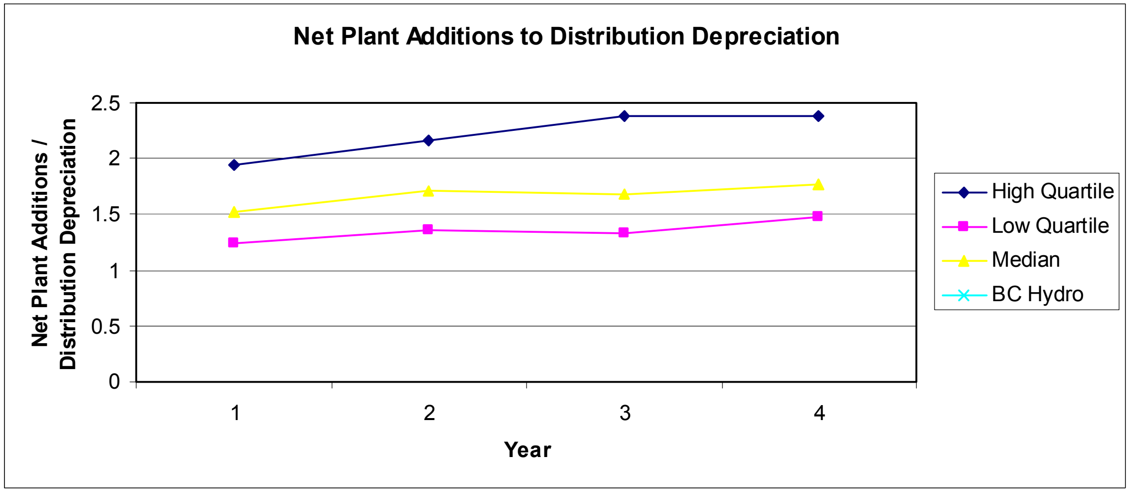




NOTE: In the absence of BC Hydro Net Distribution Plant information, but projecting the assumed impact of significantly lower capital investment levels, we would expect BC Hydro's Distribution Depreciation as a percent of Net Plant (and related Implied Average Service Life) to be in the lower quartile. This illustrates the relationship between investment levels, age of the assets, and provides a plausible explanation for deteriorating overall system reliability (SAIFI).

Overall Industry Comparisons *(Continued)*

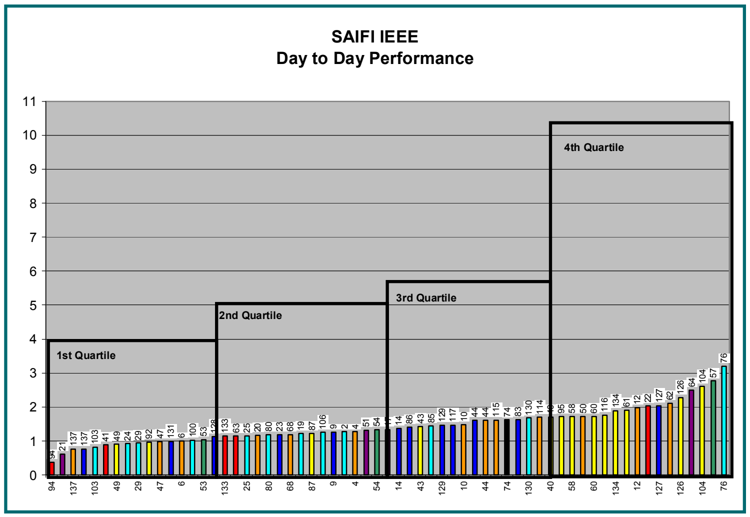
Approximately 30 percent of the utilities representing the Tier 1 peer group maintain capital investment levels that will offset the effects of aging infrastructure.

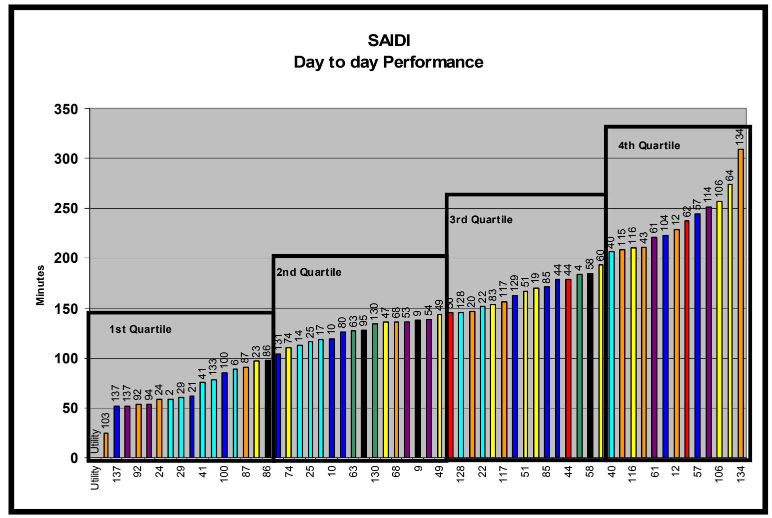


NOTE: The depreciation values provided were extremely low compared to the 118 utilities which, if accepted, yield results that are way outside the norm (the normal ratios tend to be between 1.0 and 3.0). Based on past and projected capital investment levels, we would anticipate that BC Hydro's ratios in 2006 and 2007 would be in the range of 0.5 to 0.7; and that the projected ratio for FY 2010 will approach the industry median of 1.7 (not sufficient to stem the tide of an aging electric distribution infrastructure).

Overall Industry Comparisons *(Continued)*

In comparing BC Hydro's reliability performance to industry-wide IEEE Surveys conducted in 2007, BC Hydro's 3-year average for SAIFI (1.51) equates to 3rd quartile performance (from 2nd quartile in 2006) and for SAIDI (207 minutes) 4th quartile performance (from 3rd quartile in 2006). CAIDI has deteriorated slightly (from 130 to 148 minutes), but the deterioration in SAIFI (18 percent increase in number of outages and 22 percent increase in number of customer interruptions over a 3-year period) poses the greatest challenge, particularly given BC Hydro's investing and spending levels compared to that of the first industry peer group of 118 utilities. BC Hydro has successfully implemented a customer centric strategy that, independent of the current trend in SAIFI, has resulted in improved customer satisfaction. That being said, BC Hydro's desire to better understand how an increase in capital investment and O&M spending might improve SAIFI is well-founded as a continued increase in SAIFI will likely "trump" the effectiveness of its customer-centric approach.





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Spending – Reliability Comparisons

In analyzing the relationship between Capital Investment/O&M Spending and Reliability we reviewed the:

- "Static" Impact of Investment/Spending on Reliability (plotting 3-year averages to dampen the effect of annual variations on the analyses)
- "Static" Time-phased Effect of Investment/Spending on Reliability (plotting investment/spending level against any change in reliability 2 and 3 years later)
- "Dynamic" Time-phased Effect of Investment/Spending on Reliability (plotting change in investment/spending level against any change in reliability 3 years later)

NOTE: We adopted the terms "Static" and "Dynamic" to differentiate analyses that look at the impact of level of investment/spending ("static") from those that consider the impact of a change in investment/spending ("dynamic").

Reliability performance as measured by SAIFI is likely to be impacted by both Capital Investment (Net Plant Additions) and O&M Spending; for example:

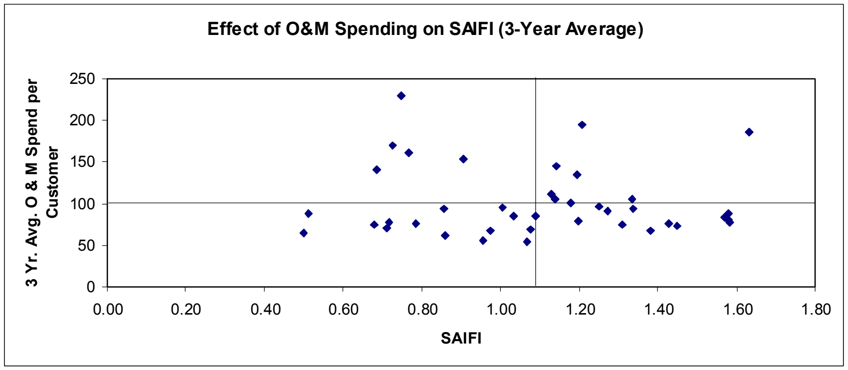
- Tree Trimming (O&M)
- Circuit Protection/Sectionalizing (Capital)
- Distribution Automation (Capital)
- Pole and Pole Top Fault Causing Equipment Repairs (O&M)

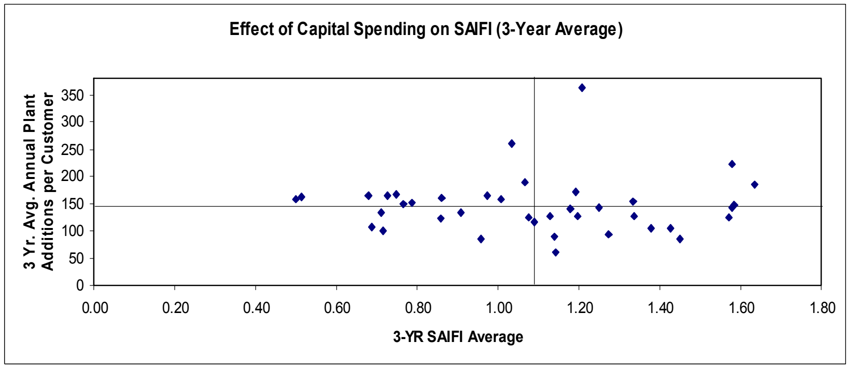
whereas reliability performance as measured by CAIDI, if impacted by spending levels at all, will more than likely be linked to O&M Spending (e.g. Storm Pre-mobilization and Installation of Directional Fault Indicators).

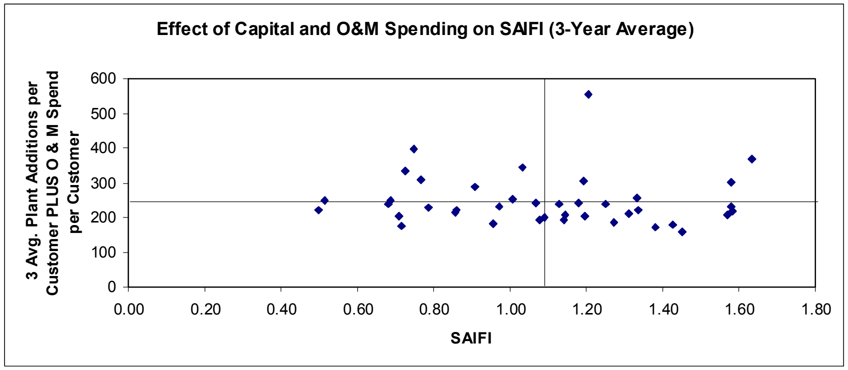
Spending vs. Reliability *(Continued)*

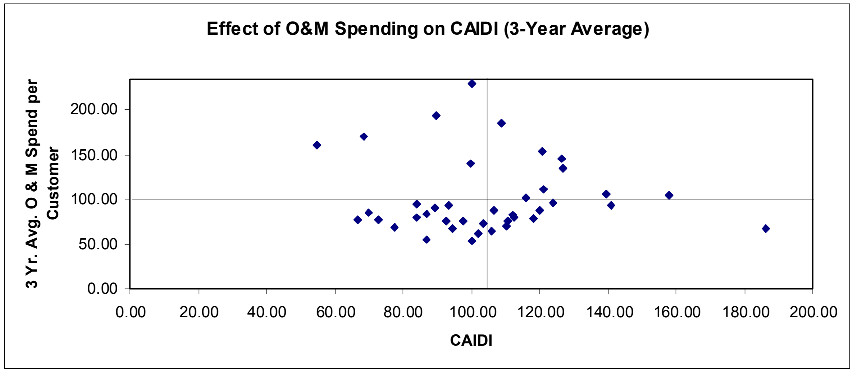
Static Comparison of Spending and Reliability

In performing a static comparison of spending and reliability, we explored the hypothesis that the level of investment/spending is a predictor of reliability performance. Three-year averages were used to dampen any anomalies that could be the result of "one-off" performance "spike" or a timing issue in reporting costs or outage results. As previously stated, we looked for possible correlation between capital investment and SAIFI, O&M spending and SAIFI, the combination of capital spending and O&M spending and SAIFI and O&M spending and CAIDI. Given that there are (1) from utility to utility, varying percentages of investments/spending levels tied directly to reliability-specific projects/programs, and (2) delays before an investment translates to an outcome, it is not surprising that there appears to be little, if any correlation in the static comparisons (refer to plots below).





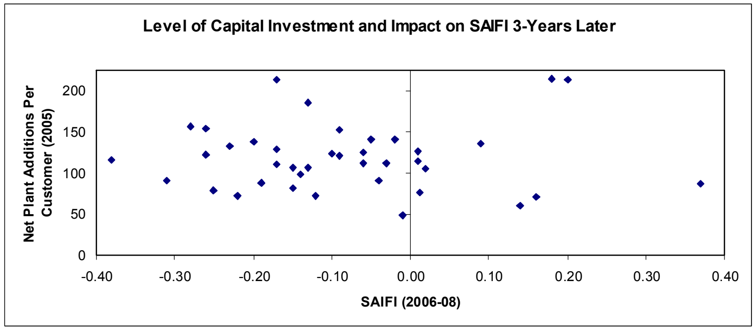


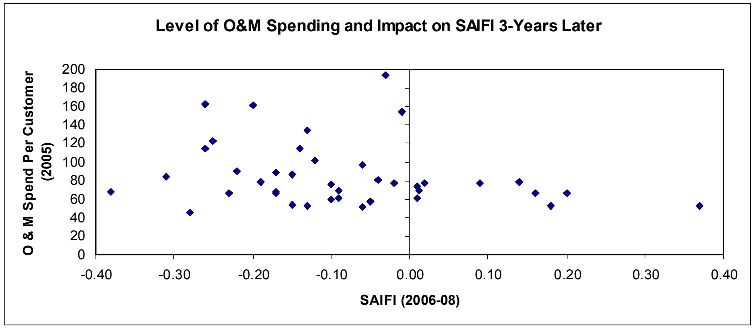


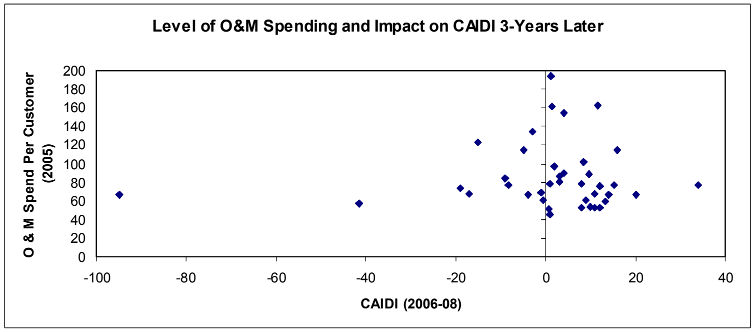
Spending – Reliability Comparisons *(Continued)*

Effect of Level of Spending (2 and 3-Years Later)

The analysis then shifted to exploring timing as a factor in correlating investment/spending with reliability. It seemed reasonable that there may be a delay between the implementation of specific projects and/or execution of programs and any effect on reliability. We looked at three scenarios, imposing a 2 and 3 year gap between actual investment/spending and the measuring of reliability for each: Level of Capital Investment and SAIFI, Level of O&M Spending and SAIFI and level of O&M Spending and CAIDI.







Summary of Analysis

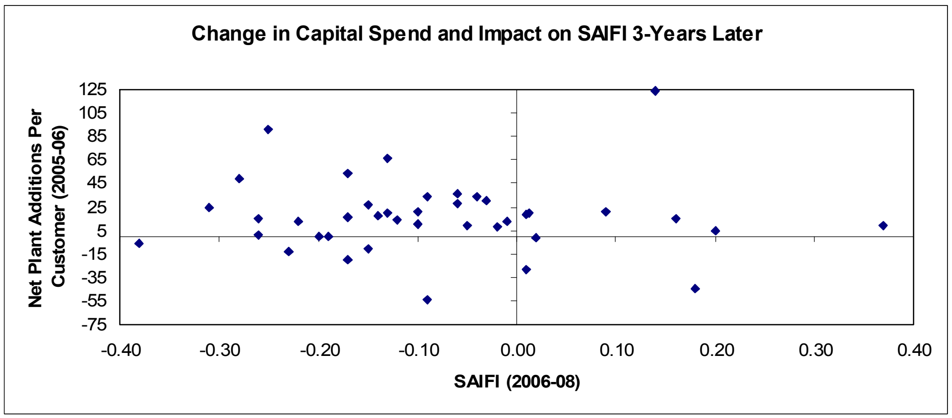
These trend plots indicate that the level of capital investment or O&M spending do have an effect on SAIFI three years later (there is a “looser” correlation when looking at a two-year lag between investment/spending and results); and there is no apparent effect on CAIDI (most likely indicative of the stronger bias towards process improvements as a driver in improving service restoration). Recognizing the number of factors that make up an investment or spending profile (many of which have no bearing on reliability), we thought it preferable to shift the focus to the impact that a change in investment or spending might have on reliability three years later, assuming that any incremental increase in either would likely be driven by a need to improve reliability (particularly given today’s economic climate); and that short of any large grid revitalization effort, the non-reliability related expenditures are already accounted for in the baseline budgets.

Spending – Reliability Comparisons *(Continued)*

Effect of Change in Level of Spending (3-Years Later)

The previous charts established that there is a relationship between investment and spending and SAIFI, though the impact will not be realized for 2 to 3 years. Recognizing that current investment and spending levels are already established and the legacy around reliability performance is realized, we then shifted our focus to investigating the impact of a change in capital investment and/or O&M spending on SAIFI, still with a 3-year lag between the expenditures and results. Each of these scenarios is graphically displayed below, and analyzed to more explicitly describe the correlation between these key variables.

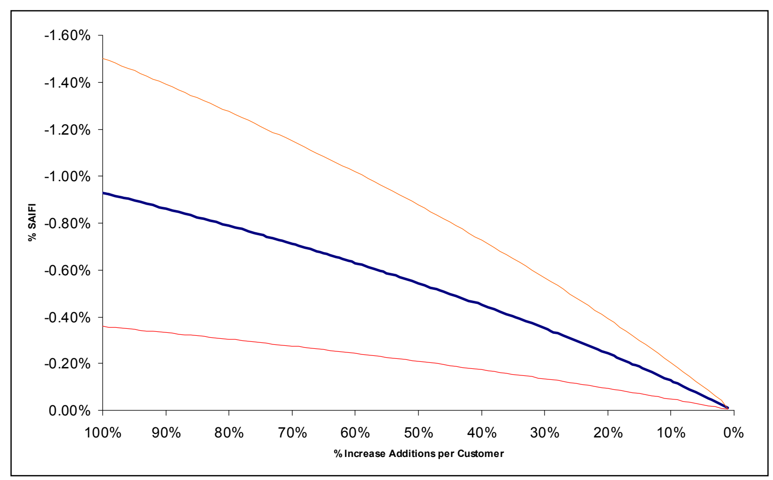
Impact of Change in Capital Investment on SAIFI (3-Years Later)



Converted to percentage of change in capital investment and SAIFI to account for the wide disparity in spending levels and actual SAIFI values

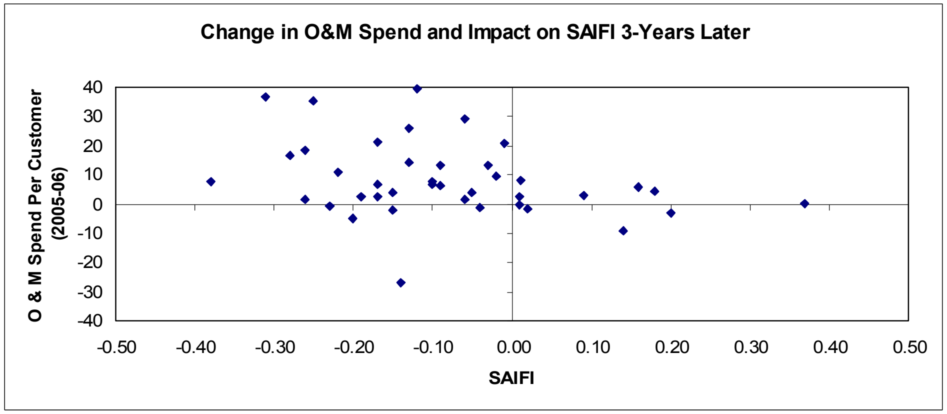
Assuming the same mix of work (e.g. reliability related, capacity additions, new business and condition), the analyses substantiate a correlation between changes in capital investment levels and changes in SAIFI (3-years later), as particularly strong (i.e. small variation) when the change in investment is between 0 and 20 percent (The red lines indicate the range of potential outcomes at a 95 percent confidence factor). The impact is not dramatic (particularly in the scenario where capital investment is increased), most likely due to the other priorities to which capital investments are assigned.

Though not shown on this plot, the change in SAIFI (percent increase or decrease) is more dramatic when decreasing the level of investment by more than 50 percent than when increasing the level of investment by more than 50 percent. Recognizing the challenge of extracting definitive explanations from such a high level view, a possible explanation is the offset of gradual annual deterioration of SAIFI due to the age and condition of the distribution assets.



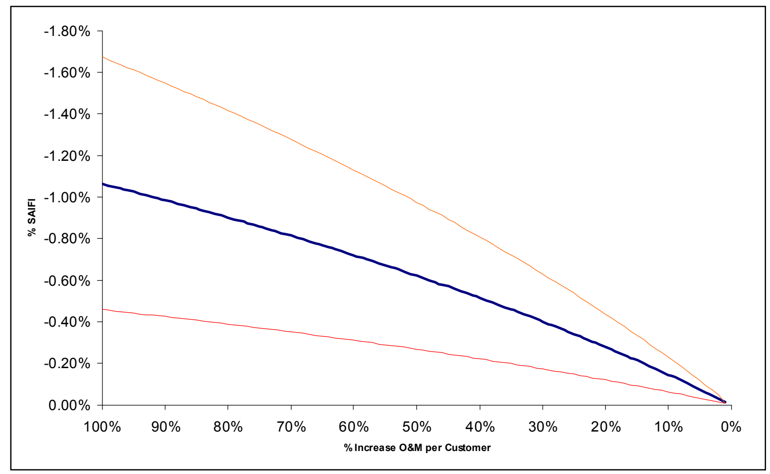
Spending – Reliability Comparisons *(Continued)*

Impact of Change in O&M Spending on SAIFI (3-Years Later)



Converted to percentage of change in O&M spending and SAIFI to account for the wide disparity in spending levels and actual SAIFI values

Similarly, the analyses substantiate that a correlation exists between changes in O&M spending levels and SAIFI (3-years later), and again, is particularly strong (i.e. small variation) when the change in spending is between 0 and 20 percent. As is the case with changes in capital investment levels, the impact is small (for reasons previously stated); and the change in SAIFI (percent increase or decrease) is more significant when decreasing the level of investment by more than 50 percent than when increasing the level of spending by more than 50 percent. Again, we would attribute this difference to the effect of age and condition of the electric distribution infrastructure (which serves as a built in offset to any effort to improve reliability).



Contents

- Executive Summary
- Context of the Analysis
- Overall Approach
- Overall Industry Comparison
- Spending – Reliability Comparisons
- Qualitative Review

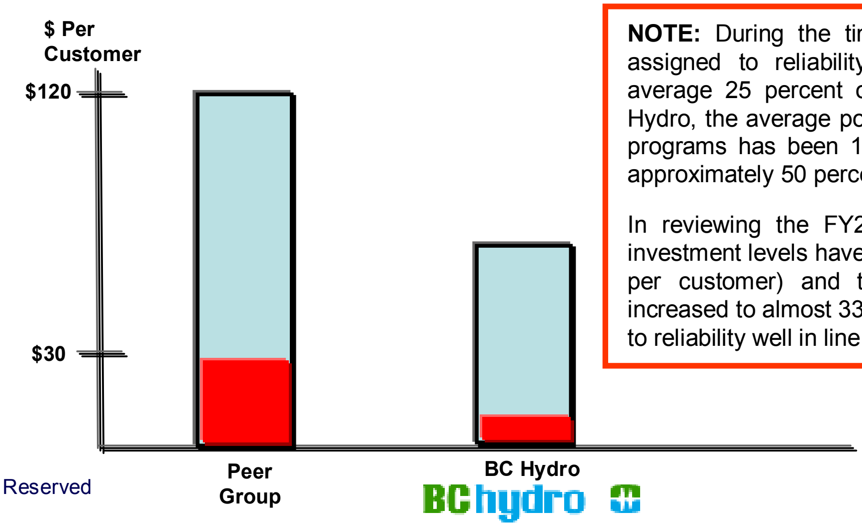
Qualitative Review

The tier 1 and 2 analyses identified the extent of any correlation between capital investment and/or O&M spending levels and reliability, but from a top-down perspective. There were a number of observations that bear highlighting, namely:

- To the extent that there is a tie between capital investment/O&M spending and reliability, there appears to be a time lag (2 to 3 years) between the actual expenditure and any noted improvement in reliability.
- Aging infrastructure presents a major challenge to maintaining, let alone achieving sustainable improvement in, reliability, resulting in networks that operate well or poorly based on the fortunes or misfortunes of good or bad weather. Capital investments in the range of 2 to 2.5 times depreciation are required over a sustained period of time to stay ahead of the problem, and the fact that approximately 70 percent of the industry falls below this range with implied average service lives of greater than 30 years is certainly a plausible explanation for why utilities struggle to meet their reliability targets.

Though these observations help shed light on some of the dynamics that drive reliability, the insights gleaned from this high level view do not provide a basis from which to predict reliability improvement as a function of capital investment and/or O&M spending levels. The purpose of this third tier was to dig deeper into the numbers, programs and practices around reliability, converse with other utilities, and review the results of other UMS Group assessments, to <u>develop thumb rules to predict improvement</u>. To accomplish this we first acknowledged the following:

- The level of capital investment/O&M spending does not, in and of itself determine reliability performance. There are a number of requirements calling for investment/spending (e.g. New Connections, Capacity, Facilities, Condition, Non-ROW Vegetation, Reliability, Capital O&M, and Forced), many of which are not tied to reliability. The following chart illustrates a comparison of BC Hydro's capital investment levels (and the portion assigned to reliability-related programs) with that of the select few utilities we interviewed:



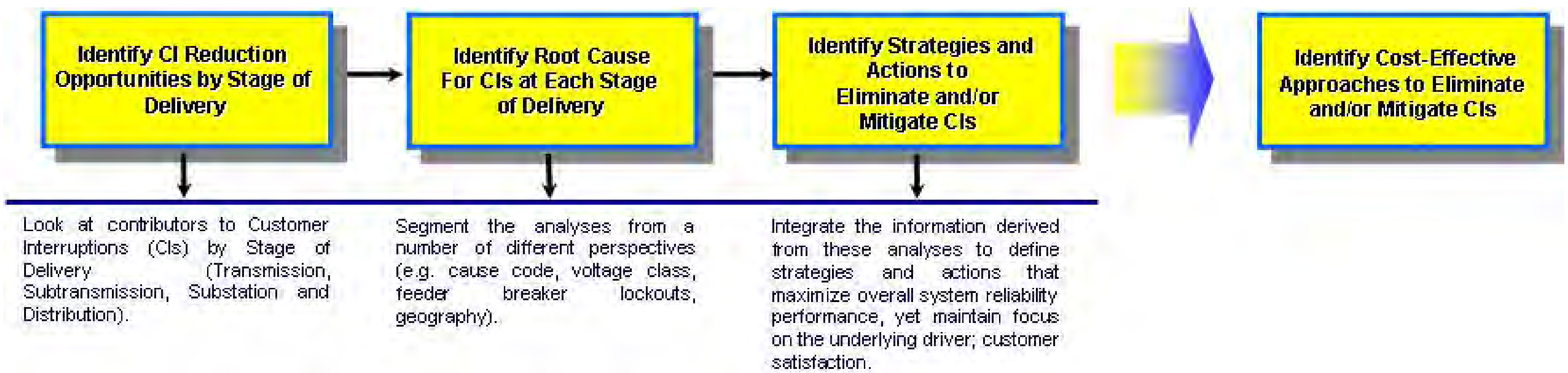
NOTE: During the time period 2006 – 2008, the $ per customer assigned to reliability-related programs (denoted in red) typically average 25 percent of the total capital budget. In the case of BC Hydro, the average portion of capital expenditures related to reliability programs has been 15 percent, and the level of total investment is approximately 50 percent of the industry median.

In reviewing the FY2010 budget we note that the overall capital investment levels have increased to meet the industry median (to $126 per customer) and the percent assigned to reliability has been increased to almost 33 percent. (bringing the absolute dollars assigned to reliability well in line with industry norms)

Qualitative Review

– Properly managed O&M spending is an essential element of maintaining acceptable reliability (ROW vegetation management falls under this category as does the effective preventive and corrective maintenance of equipment). However, with the exception of applying enhanced tree trimming, the nature of the programs addressed by O&M spending are longer range with respect to having a measurable impact on reliability and do not lend themselves to year-to-year projections of changes in customer minutes or customer hours. Therefore, the qualitative review focused on capital investment (except for that portion of enhanced tree trimming that falls under the O&M expense budget).

– We assumed that the level of capital investment and O&M spending allocated to reliability programs was sufficient, and used the following approach to ensure effective (optimum) application of this funding.



Combined with perspectives and insights from individuals representing the 8 previously identified utilities we extended this approach to establish a rationale that not only addressed the linkage between investment/spending levels and reliability, but allowed for some degree of accuracy in predicting the impact of specific initiatives on key system measures.

Qualitative Review *(Continued)*

We first confirmed the following:

- Between 60 and 80 percent of the customer interruptions occur on distribution circuits (BC Hydro appears to range between 64 and 77 percent)
- Though only 10 to 15 percent of the distribution outages affect more than 100 customers, these outages account for 65 to 80 percent of the customer interruptions and customer hours lost
- Between 45 and 65 percent of the outages are attributed to line failures, equipment failures and trees (BC Hydro appears to range between 43 and 63 percent)

Further, we established that the primary causes of outages on distribution circuits experienced by BC Hydro are typical across the industry, namely: Adverse Weather, Vegetation and Equipment Failure.

Therefore, initiatives and actions that target storm hardening and sectionalizing the feeder backbone and any other worst performing circuits were unanimously viewed as most cost-effective, and to the extent they comprised a significant portion of the scope of a utility's reliability program, there was general consensus that efforts in these areas provide a good proxy from which to predict changes in overall system reliability.

The following discussion provides rules of thumb that UMS Group has applied in presenting reliability improvement programs over the past 3 years, with remarkably accurate results. Keep in mind that the electric distribution <u>systems are gradually deteriorating (in the range of 3 to 5 percent per year), so any projected improvement needs to reflect a net of these additive improvements and this deterioration</u>. Further, for these numbers to hold true, there needs to be a consistent and persistent focus on reliability.

There are a number of actions that utilities typically employ to storm harden and sectionalize the feeder backbone (as well as any other worst performing circuits); namely: Circuit Protection (e.g. install reclosers and add fuses), enhanced tree trimming and danger tree removal, and pole and pole top fault causing equipment repair and replacement:

Major Equipment Failure remains an issue, but the dollars spent can rarely be justified on the basis of reliability alone (the <u>cost of an avoided customer interruption caused by major equipment failure approaches $1,000</u> – 10 to 15 times the cost of the other initiatives). Rather, most utilities approach major equipment failure by applying a "run to failure" criteria, and only enter into a more proactive and programmatic approach as part of an overall grid revitalization program (likely linked to support of a distribution automation and/or a SmartGrid/AMI strategy).

Qualitative Review *(Continued)*

Circuit Protection (Sectionalize and Fusing of Taps):

The following table (which includes the installation of fuses as the taps) has been used to calculate the cost per avoided customer interruption when installing reclosers on the feeder backbone.

Backbone Outages Per Year	Customer Interruptions per Outage			
	250	**500**	**1,000**	**2,000**
0.5	$800	$400	$200	$100
1	$400	$200	$100	$50
2	$200	$100	$50	$25
3	$133	$67	$33	$17
4	$100	$50	$25	$13

The variables that drive these cost parameters are the number of customer interruptions per outage and the number of outages experienced by the specific circuit per year. Lacking that level of detail, we typically use $100 per avoided customer interruption as a reasonable estimate. Applying this to the installation of a $35,000 recloser would equate to a reduction of 350 CIs per newly installed recloser.

Enhanced Tree Trimming:

Given that tree-related outages comprise almost one-third of BC Hydro’s customer interruptions and customer hours lost, and assuming that the current program is “on cycle,” we would suggest shifting to an optimized tree trimming program where greater emphasis is placed on the feeder backbone, those circuits identified as worst performers, and overhanging limbs and structurally weak trees.

The cost of this type of approach for the more problematic circuits is in the range, on average, of $20,000 per circuit which typically equates to $40 per customer interruption avoided. Thus, a circuit fitting this criteria (generally a feeder backbone) would realize an elimination of 500 customer interruptions per year (assuming a 4-year tree trimming cycle). Expanding enhanced tree trimming to include less-problematic circuits will achieve diminishing returns, where the cost of an avoided customer interruption is in the range of $120. Therefore, a general ballpark figure to apply (in the absence of information regarding the problematic nature of a specific circuit) would be $80 per customer interruption avoided or 250 customer interruptions per circuit.

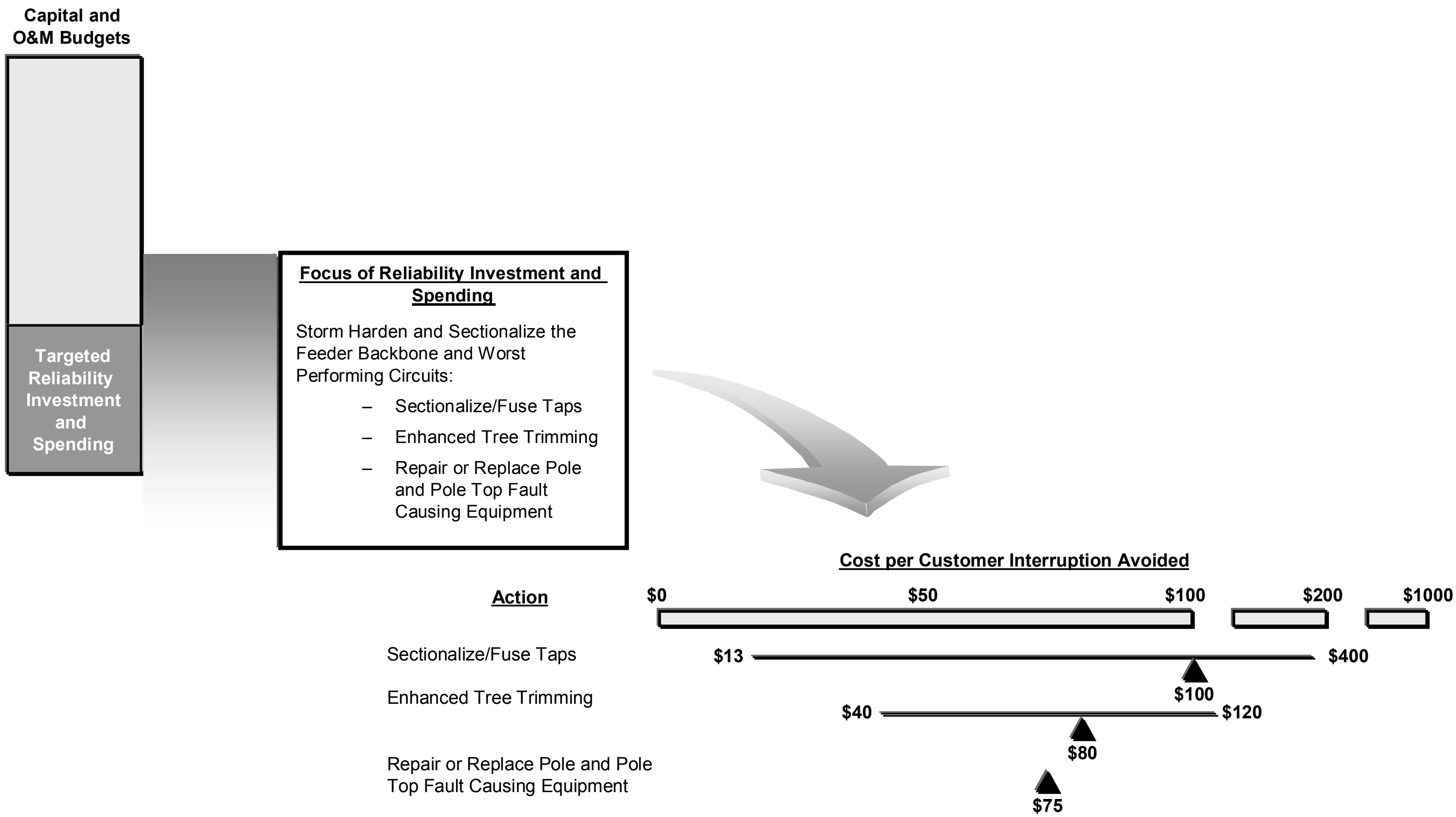
Repair or Replace Pole and Pole Top Fault Causing Equipment

The cost of this type of program is viewed as incremental to any existing line inspection and repair program. Assuming a 20 percent improvement in customer interruptions, we generally use a unit cost of $75 per customer interruption avoided.

Qualitative Review *(Continued)*

Summary

Summarizing this portion of the study, the following illustration can be used to outline the extent to which a utility can predict improvement in overall system reliability (assuming a well-targeted capital investment and O&M spending strategy):



NOTE: By applying the "Cost per CI Avoided" and determining a predicted CI avoided for each budgeted project; aggregating the entire investment and spending portfolio and subtracting out 5 percent of the previous years CIs, one can arrive at a projected CI increase/decrease for the entire portfolio of reliability projects/programs.

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David Ince Information Request No. **2.4.0** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
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Topic: **Performance Metrics**

Reference: **Appendix E: Service Plan. Page 17 of 36.**
Ince IR 1.1.1

The response to Ince 1.1.1 states: "The BC Hydro system is highly complex and dynamic and it is difficult to make a direct link between the SAIDI, SAIFI and Generation Facility Forced Outage Factor performance metrics and investments in the system. These metrics are influenced by factors beyond capital and maintenance investment including operational procedures and uncontrollable events".

2.4.0 Can BC Hydro provide access to the most relevant internal and external studies that attempt to quantify the relationship between performance metrics and system expenditures?

RESPONSE:

Please refer to BC Hydro's response to INCE IR 2.3 where we provide a report on a study by UMS Group Inc., an external study that attempted to quantify the relationship between reliability performance and investment.

David Ince Information Request No. **2.5.0** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
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TOPIC: **Water License Renewals**

Reference: **CEC 1.74.3**
Yukon Energy Water License renewal for Aishihik Hydro plant:
https://www.cbc.ca/news/canada/north/yukon-energy-champagne-aishihik-agreement-issues- 1.4933076
https://yukonenergy.ca/energy-in-yukon/projects-facilities/aishihik-hydro-plant/water-licensing- renewal/
https://cafn.ca/aishihik-relicensing-2019/

2.5.0 Does BC Hydro consider it mandatory for it and/or the provincial government to obtain First Nations consent on any or all water license renewals?

RESPONSE:

The *Water Sustainability Act* (the legislation which governs BC Hydro's water licence renewals) does not require BC Hydro to obtain First Nations' consent in relation to water licence renewals, nor does BC Hydro have any agreements with First Nations that include a requirement to obtain consent for a water license renewal. BC Hydro has been engaging with First Nations and seeking their input through the water licence renewal process and will continue to do so.

BC Hydro cannot speak for the Government of B.C. on this issue.

David Ince Information Request No. **2.6.0** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
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TOPIC: **Water License Renewals**

Reference: **CEC 1.74.3**
Yukon Energy Water License renewal for Aishihik Hydro plant:
https://www.cbc.ca/news/canada/north/yukon-energy-champagne-aishihik-agreement-issues- 1.4933076
https://yukonenergy.ca/energy-in-yukon/projects-facilities/aishihik-hydro-plant/water-licensing- renewal/
https://cafn.ca/aishihik-relicensing-2019/

2.6.0 Please specify the budgeted dollar allocations for the processes involved in these 3 license renewals? Are these fully specified and costed in Table 6-18 of the Application.

RESPONSE:

The total budget for these water license renewals is $9.8 million which includes $3.7 million prior to the test period, $1.4 million during the test period and $4.7 million after the test period.

The budget for the three water license renewals within the test period is $99,000 for Alouette, $145,000 for Bridge, and $154,000 for Shuswap as well as $1.05 million for common project costs. These test period costs, totalling $1.4 million, are included within Table 6-18 of Chapter 6 of the Application.

TOPIC: **Water License Renewals**

Reference: **CEC 1.74.3**
Yukon Energy Water License renewal for Aishihik Hydro plant:
https://www.cbc.ca/news/canada/north/yukon-energy-champagne-aishihik-agreement-issues- 1.4933076
https://yukonenergy.ca/energy-in-yukon/projects-facilities/aishihik-hydro-plant/water-licensing- renewal/
https://cafn.ca/aishihik-relicensing-2019/

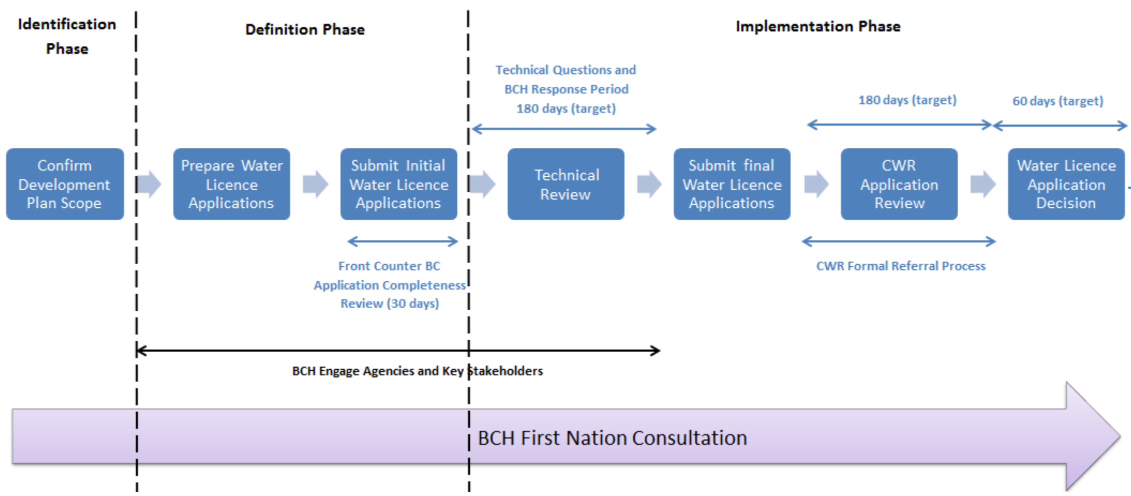
2.7.0 Please indicate the high-level steps and scheduled timeframe involved in the successful achievement of these renewals.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.263.1 for the dates that the applications were submitted, expected completion of the technical review phase, and the target date of decision by the Comptroller of Water Rights.

The Government of B.C.'s process for a water licence renewal can be found at: https://portal.nrs.gov.bc.ca/web/client/-/water-licence-application.

A high-level diagram showing the steps and timeframe for a BC Hydro water licence application is provided below.



David Ince Information Request No. **2.8.0** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
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TOPIC: **Water License Renewals**

Reference: **CEC 1.74.3**
Yukon Energy Water License renewal for Aishihik Hydro plant:
https://www.cbc.ca/news/canada/north/yukon-energy-champagne-aishihik-agreement-issues- 1.4933076
https://yukonenergy.ca/energy-in-yukon/projects-facilities/aishihik-hydro-plant/water-licensing- renewal/
https://cafn.ca/aishihik-relicensing-2019/

2.8.0 Has BC Hydro anticipated or in any way planned for a contingency condition where it is required to restore these facilities to original water course and/or original seasonal flow conditions?

RESPONSE:

No, BC Hydro has not included such contingencies in its project planning. Please refer to BC Hydro's response to INCE IR 2.9.0, for estimated energy losses should the water licenses not be renewed.

David Ince Information Request No. **2.9.0** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
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TOPIC: **Water License Renewals**

Reference: **CEC 1.74.3**
Yukon Energy Water License renewal for Aishihik Hydro plant:
https://www.cbc.ca/news/canada/north/yukon-energy-champagne-aishihik-agreement-issues- 1.4933076
https://yukonenergy.ca/energy-in-yukon/projects-facilities/aishihik-hydro-plant/water-licensing- renewal/
https://cafn.ca/aishihik-relicensing-2019/

2.9.0 Has BC Hydro determined an opportunity value for these 3 facilities, as in the long-term additional costs to BC Hydro (replacement energy, capacity and infrastructure costs) if these facilities have to be restored to either original water course, or original seasonal flow conditions?

RESPONSE:

BC Hydro has not determined the cost that would be required to replace the energy and capacity from these facilities.

Each of the three facilities referred to in BC Hydro's response to CEC IR 1.74.3 has multiple water licenses and only a subset of those licenses is subject to renewal. The remaining licenses already exist in perpetuity. As part of the water license applications, BC Hydro did include the lost energy should the specific water licenses up for renewal not be renewed. The table below summarizes the results presented in the three applications.

Facility	Total Number of Licenses	Number of Licenses Up for Renewal	Lost Energy if Licenses Not Renewed
Shuswap	4	1 storage 1 diversion	Lost energy for full facility ~37 GWh/yr Lost energy ~8 GWh/yr
Alouette	3	1 diversion	~11 GWh/yr
Bridge	12	2 storage 5 diversion	If all seven licenses are not renewed then ~1400 GWh/yr

Topic: **Burrard Thermal**

Reference: **Ince 1.7.15 and BC Clean Energy Act Part 1 (2o).**

The response to Ince 1.1.1 states: "The BC Hydro system is highly complex and dynamic and it is difficult to make a direct link between the SAIDI, SAIFI and Generation Facility Forced Outage Factor performance metrics and investments in the system. These metrics are influenced by factors beyond capital and maintenance investment including operational procedures and uncontrollable events".

2.10.0 Does BC Hydro interpret the provision in the Clean Energy Act requiring that the corporation: "to achieve British Columbia's energy objectives without the use of nuclear power" to prohibit the use of fusion-based nuclear power?

RESPONSE:

Section 2(o) of the *Clean Energy Act* is an energy objective that the BCUC must "consider" in making certain decisions; it is not a legal prohibition against nuclear power, be it fusion-based or fission-based nuclear power.

BC Hydro notes that fusion-based nuclear power remains a subject of research at present and is not a technologically viable nuclear option like nuclear fission. There are no fusion-based nuclear power facilities in commercial operation in the world.

David Ince Information Request No. **2.11.0** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit:** **B-13**

Topic: **Load Forecast**

The response to Ince 1.1.1 states: “The BC Hydro system is highly complex and dynamic and it is difficult to make a direct link between the SAIDI, SAIFI and Generation Facility Forced Outage Factor performance metrics and investments in the system. These metrics are influenced by factors beyond capital and maintenance investment including operational procedures and uncontrollable events”.

2.11.0 Please indicate the effect on the load forecast of the July 18 2019 federal government announcement of funding for electric busses in BC.

RESPONSE:

The funding announcement for electric buses came after the October 2018 Load Forecast was finalized. BC Hydro continues to monitor developments in the transportation sector and will incorporate the effects of these developments in future load forecasts.

David Ince Information Request No. **2.12.0** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

Topic: **Load Forecast**

The response to Ince 1.1.1 states: "The BC Hydro system is highly complex and dynamic and it is difficult to make a direct link between the SAIDI, SAIFI and Generation Facility Forced Outage Factor performance metrics and investments in the system. These metrics are influenced by factors beyond capital and maintenance investment including operational procedures and uncontrollable events".

2.12.0 Regarding the July 8 letter by Chevron to the provincial Environmental Assessment Office Re: Kitimat LNG electrification; please indicate the expected effect on BC Hydro's load forecast.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 2.204.1 which provides a confidential update on the Kitimat LNG project and concludes that given the current project schedule, Kitimat LNG would not have an impact on the October 2018 Load Forecast within the test period or within the fiscal 2019 to fiscal 2024 period.

Topic: **Cost of Energy and Independent Power Producers**

Reference: **BCUC 1.15.1**

Regarding the reference to: 'a time of delivery factor', please explain how BC Hydro adjusts compensation to IPPs for energy delivered based on a monthly and intra-day factor. Please provide the tables (2 x 12, or 3 x 12) price adjustment matrices used by BC Hydro by major IPP procurement process.

2.13.0 Please indicate the timeframe during which these tables were first issued, as in when the applicable standard-form IPP contracts were finalized. Have these price adjustment matrices been altered since they were first applied under the respective calls for which they were created?

RESPONSE:

The requested tables for the major procurement processes are provided below. The approximate date of issue is also listed in parentheses following the name of each major procurement process. While different price adjustment matrices apply to different EPAs depending on the procurement process, BC Hydro has not amended the price adjustment matrices within each EPA since issuing the standard form EPAs for each of the respective calls.

Generally, the price for energy delivered in each hour is equivalent to the annual escalated EPA price multiplied by the monthly time of delivery factors for each relevant hourly period that the energy was delivered (i.e., Heavy Load Hours [HLH], Light Load Hours [LLH], Super Peak, Peak, Off-Peak and On-Peak)[1]. For example, for the F2006 Call for Tenders, Small Project (Table 3), energy delivered during heavy load hours in April would be compensated at a price that is 103 per cent of the escalated bid price; whereas energy delivered during light load hours in June would be compensated at a price that is 71 per cent of the escalated bid price.

[1] **For Tables 1, 2, 3 and 4 below, "HLH" or "Heavy Load Hours" means the hours commencing at 06:00 PPT and ending at 22:00 PPT Monday through Saturday inclusive but excluding British Columbia statutory holidays; "LLH" or "Light Load Hours" means all hours other than Heavy Load Hours.**

For Table 5 below, "Super-Peak" means the hours commencing at 16:00 PPT and ending at 20:00 PPT Monday through Saturday inclusive, but excluding British Columbia statutory holidays. "Peak" means the hours commencing at 06:00 PPT and ending at 16:00 PPT, and commencing at 20:00 PPT and ending at 22:00 PPT, Monday through Saturday inclusive, but excluding British Columbia statutory holidays. "Off-Peak" means all hours other than Super-Peak hours and Peak hours. "On-Peak" means all Peak hours and Super-Peak hours.

Table 1: 2003 Green Power Generation Call (October 2003)

Month	HLH (%)	LLH (%)
January	117	98
February	110	105
March	106	103
April	103	85
May	98	67
June	98	68
July	105	82
August	107	90
September	106	98
October	105	98
November	112	104
December	117	98

Table 2: F2006 Call for Tenders, Large Project (March 2006)[2]

Month	Escalated Bid Price Adjustment (%)		Escalated Discount Amount Adjustment (%)	
	HLH	LLH	HLH	LLH
January	113	97	88	103
February	109	102	92	98
March	105	100	95	100
April	103	88	97	114
May	104	73	96	137
June	104	71	96	141
July	104	77	96	130
August	104	97	96	103
September	105	98	95	102
October	103	89	97	112
November	106	104	94	96
December	117	101	85	99

2 https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/info/pdf/info_open_cft_large_project_epa_clean.pdf.

Table 3: F2006 Call for Tenders, Small Project (March 2006)[3]

	HLH (%)	LLH (%)
January	113	97
February	109	102
March	105	100
April	103	88
May	104	73
June	104	71
July	104	77
August	104	97
September	105	98
October	103	89
November	106	104
December	117	101

Table 4: 2008 Standing Offer Program, Appendix 4 (June 2007)

	HLH (%)	LLH (%)
January	125	106
February	126	110
March	114	106
April	103	95
May	92	76
June	90	72
July	91	72
August	95	81
September	96	88
October	108	97
November	109	102
December	122	102

3 https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/info/pdf/info_open_cft_small_project_epa_clean.pdf.

Table 5: Bioenergy Call for Power – Phase I (May 2008)[4], Clean Power Call (October 2008)[5], Integrated Power Offer (January 2010), Bioenergy Call for Power – Phase II (October 2010)[6], 2010 Standing Offer Program (April 2016)[7,8]

Month	Time of Delivery Factor (TDF)				
	Super-Peak (%)	Peak (%)	Off-Peak (5)		On-Peak (%)
January	141	122	105		127
February	124	113	101		116
March	124	112	99		115
April	104	95	85		97
May	90	82	70		84
June	87	81	69		83
July	105	96	79		98
August	110	101	86		103
September	116	107	91		109
October	127	112	93		116
November	129	112	99		116
December	142	120	104		126

4 https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/info/doc/info_bioenergy_call_phase_i_specimen_epa_word.doc.

5 https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/info/doc/info_-_cpc_-_specimen1.doc.

6 https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/acquiring_power/2010q4/Specimen_epa.DOC.

7 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/standing-offer/standing-offer-program-rules.pdf .

8 BC Hydro notes that the 2010 Standing Offer Program EPA did not include "On-Peak" time of delivery factors.

Topic: **Cost of Energy and Independent Power Producers**

Reference: **BCUC 1.15.1**

Regarding the reference to: 'a time of delivery factor', please explain how BC Hydro adjusts compensation to IPPs for energy delivered based on a monthly and intra-day factor. Please provide the tables (2 x 12, or 3 x 12) price adjustment matrices used by BC Hydro by major IPP procurement process.

2.14.0 When IPP renewals are undertaken, is the price adjustment matrix the same as when the IPP contract was signed, or updated with adjustments recognizing BC Hydro's more recent load and supply situation?

RESPONSE:

BC Hydro's recent run of river hydro EPA renewals do not include a time of delivery price adjustment. Going forward, this type of price adjustment may or may not be included in the terms of EPA renewals depending on the characteristics of the project, the desired product and the outcome of the negotiations. BC Hydro notes that we typically consider the time of delivery factors in the analysis of cost-effectiveness of an EPA (e.g., in determining BC Hydro's opportunity cost).

Topic: **Cost of Energy and Independent Power Producers**

Reference: **BCUC 1.15.1**

Regarding the reference to: 'a time of delivery factor', please explain how BC Hydro adjusts compensation to IPPs for energy delivered based on a monthly and intra-day factor. Please provide the tables (2 x 12, or 3 x 12) price adjustment matrices used by BC Hydro by major IPP procurement process.

2.15.0 If BC Hydro were to develop a new price matrix (2 x 12 or 3 x 12 or other) for IPP energy delivery, based on its currently foreseeable energy balance, directionally, how would the table be altered?

RESPONSE:

As discussed in BC Hydro's response to INCE IR 2.14.0, BC Hydro may or may not include a time of delivery price adjustment in the terms of future EPA renewals depending on the characteristics of the project, the desired product and the outcome of the negotiations.

BC Hydro notes that the use of market price as a conservative interim assumption was recently adopted for evaluating cost-effectiveness of EPAs on the integrated system during surplus and deficit periods, other than certain exceptions (such as the Biomass Energy Program) or if a facility provides additional benefits.

As provided in BC Hydro's evidence to the BCUC's Proceeding for the Renewal of Sechelt, Brown Lake, and Walden North EPAs, the table below presents an updated view of the market price adjusters for peak and off-peak hours[1] in each month based on BC Hydro's ABB Fall 2017 Reference Case market price forecast.[2] BC Hydro expects that its EPA renewal approach, including the consideration of time of delivery price adjustments, will be revisited as part of the process for BC Hydro's 2021 Integrated Resource Plan.

[1] "Peak hours" means the hours commencing at 06:00 PPT and ending at 22:00 PPT Monday through Saturday inclusive but excluding British Columbia statutory holidays; "Off-Peak Hours" means all hours other than Peak Hours.

[2] BC Hydro is in the process of reviewing ABB's Fall 2018 Reference Case and has not completed its determination of the modifications that will be made. Typically, BC Hydro makes adjustments to price forecast model inputs including changes to reflect up to date information on the generation profiles of large hydro facilities in the Pacific Northwest that might not have been reflected in the ABB forecast model and changes to load inputs to reflect BC Hydro's most recent load forecast.

	Peak (%)	Off-Peak (%)
January	**125**	**106**
February	**126**	**110**
March	**114**	**106**
April	**103**	**95**
May	**92**	**76**
June	**90**	**72**
July	**91**	**72**
August	**95**	**81**
September	**96**	**88**
October	**108**	**97**
November	**109**	**102**
December	**122**	**102**

David Ince Information Request No. **2.16.0** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit:** **B-13**

Topic: **Cost of Energy and Independent Power Producers**

Reference: **BCUC 1.15.1**

Regarding the reference to: 'a time of delivery factor', please explain how BC Hydro adjusts compensation to IPPs for energy delivered based on a monthly and intra-day factor. Please provide the tables (2 x 12, or 3 x 12) price adjustment matrices used by BC Hydro by major IPP procurement process.

2.16.0 Referencing the BCUC 1.32 IR series regarding the renewal of IPP contracts, why should BC Hydro pay more than strict variable operating costs to IPPs, post-contract expiry?

RESPONSE:

BC Hydro may consider a price higher than variable operating costs for an EPA renewal because IPPs may have additional fixed costs that may be required over the renewal term, including sustaining capital investments and fixed operating costs. BC Hydro reviews IPP cost of service submissions and condition assessments (often with the assistance of third party consultants) to identify cost reductions that may be discussed during EPA negotiations.

BC Hydro notes that an IPP’s cost of service is only one of a number of factors considered in evaluating the price paid to an IPP for an EPA renewal. BC Hydro also considers BC Hydro’s opportunity cost, the IPP’s opportunity cost, the impact to BC Hydro’s rates plan, and system benefits and support characteristics (if applicable). In some circumstances, BC Hydro may consider a price lower than the IPP’s variable costs for an EPA renewal.

Topic: **Risk Identification and Management**

Reference: **Ince 1.10.1**

2.17.0 Please indicate where the key organizational, strategic, operational, etc. risks identified by BC Hydro fit on the generic BC Hydro Risk matrix. That is, please quantify the expected probably and severity of the prioritized risks for the corporation. Based on this assessment, what are the highest risks faced by BC Hydro?

RESPONSE:

Attachments 1 and 2 to this response provide our current Enterprise Risk Landscape for fiscal 2020, including qualitative risk ratings for each risk based on the dimensions and rating scale described below.

BC Hydro does not use a quantitative assessment of severity and likelihood for the risks appearing on the Enterprise Risk Landscape that was provided in BC Hydro's response to INCE IR 1.10.1.

Instead, a qualitative assessment is performed with input from internal subject matter experts and review and input from BC Hydro's Executive Team and Board of Directors. This approach allows for a broad range of enterprise risks to be monitored and discussed, including high severity/low probability risks that may otherwise be ranked low priority using a mathematical prioritization approach.

This qualitative assessment is based on a High, Medium, and Low scale (or Fast, Moderate, and Slow in the case of speed of onset) and is applied to each risk identified on the Enterprise Risk Landscape for the following dimensions: Severity, Likelihood, Speed of Onset, Ability to Mitigate, and overall Risk Priority. A full refresh of the Enterprise Risk Landscape and the qualitative ratings is performed annually, with the qualitative assessment being reviewed and adjusted as needed on a quarterly basis.

F20 Risk Landscape

ORGANIZATIONAL RISKS

Succession Planning - *Risk of not being adequately prepared for the loss of personnel*

Workplace Culture - *Risk that our workplace culture is not inclusive and safe for our employees*

STRATEGIC RISKS

Customer Expectations - *Risk of not meeting customers' expectations*

Shareholder Expectations - *Risk that we are unable to meet Shareholder expectations*

Advancing Reconciliation - *Risk that we are unable to advance reconciliation and meet expectations in the context of implementing UNDRIP*

Load - *Risk we are unable to effectively respond to dynamic load variability*

COMPLIANCE RISKS

Mandatory Reliability Standards - *Risk of not meeting regulatory requirements of the Mandatory Reliability Standards*

WorkSafeBC - *Risk of not meeting a WorkSafeBC regulatory requirement*

Environment - *Risk of not meeting an Environmental regulatory requirement*

FINANCIAL RISKS

Debt - *Risk of our debt being deemed not self-supported by Rating Agency*

Regulatory Accounts - *Risk of loss of ability to use Regulatory Accounts*

OPERATIONAL RISKS

Site C Delivery - *Risk of not delivering the Site C project on-time and on-budget*

Technology Implementation - *Risk that IT solutions do not adequately meet current and future business needs*

Capital Planning & Project Delivery - *Risk that the development & implementation of the Capital Plan does not meet future business needs*

Reliability - *Risk of not meeting our reliability targets*

Water Management - *Risk that we are unable to manage the impacts of variable water inflows*

HAZARD RISKS

Dam Safety - *Risk of a dam safety incident*

Emergency Preparedness - *Risk the organization is not prepared to respond to a significant emergency*

Cybersecurity - *Risk that a cybersecurity incident causes a significant disruption of our operations or loss of data*

Serious Injury / Fatality - *Risk of a serious injury or fatality*

EXTERNAL

Geopolitical & Macroeconomic Conditions
Risk that geopolitical and macroeconomic conditions negatively impact our business

BCUC Application Approval
Risk of uncertainty related to regulatory decisions

Climate Change
Risk of not being sufficiently prepared for the impacts of climate change

Disruptive Technologies
Risk that disruptive technologies negatively impact our business

F20 Enterprise Risks – Risk Assessments for F20 Q1

Organizational

RISK	Severity	Likelihood	Speed of Onset	Ability to Mitigate	Risk Priority
Succession Planning	Low	Medium	Fast	High	Medium
Workplace Culture	Low	Medium	Fast	High	High

Strategic

RISK	Severity	Likelihood	Speed of Onset	Ability to Mitigate	Risk Priority
Customer Expectations	Medium	Medium	Medium	High	Medium
Shareholder Expectations	Medium	Medium	Medium	Medium	Medium
Advancing Reconciliation	Medium	Medium	Medium	Medium	Medium
Load	Medium	High	Fast	Medium	Medium

Compliance

RISK	Severity	Likelihood	Speed of Onset	Ability to Mitigate	Risk Priority
Mandatory Reliability Standards	Medium	Medium	Fast	High	Medium
WorkSafeBC	High	High	Fast	Medium	Medium
Environment	Medium	Low	Fast	High	Low

Financial

RISK	Severity	Likelihood	Speed of Onset	Ability to Mitigate	Risk Priority
Debt	Medium	Medium	Slow	Medium	Low
Regulatory Accounts	Medium	Medium	Medium	Medium	Medium

Operational

RISK	Severity	Likelihood	Speed of Onset	Ability to Mitigate	Risk Priority
Site C Delivery	High	Medium	Medium	Medium	High
Technology Implementation	Medium	Medium	Medium	High	Medium
Capital Planning & Project Delivery	Medium	Medium	Medium	High	Medium
Reliability	Low	Medium	Medium	Medium	Low
Water Management	Medium	Medium	Medium	High	Medium

Hazard

RISK	Severity	Likelihood	Speed of Onset	Ability to Mitigate	Risk Priority
Dam Safety	High	Low	Fast	Medium	High
Emergency Preparedness	High	Low	Fast	Medium	Medium
Cybersecurity	Medium	Medium	Fast	Medium	Medium
Serious Injury / Fatality	Medium	Medium	Fast	Medium	Medium

External

RISK	Severity	Likelihood	Speed of Onset	Ability to Mitigate	Risk Priority
Geopolitical & Macroeconomic Conditions	Medium	Medium	Slow	Low	Low
BCUC Application Approval	Medium	High	Medium	High	Medium
Climate Change	Medium	Medium	Slow	Medium	Medium
Disruptive Technologies	Medium	Medium	Medium	Medium	Low

Topic: **Risk Identification and Management**

Reference: **Ince 1.10.1**

2.18.0 How are these risks different for BC Hydro's ratepayers?

RESPONSE:

All of the risks on BC Hydro's fiscal 2020 Enterprise Risk Landscape have the potential to impact BC Hydro's mission of safely providing customers with reliable, affordable, clean electricity. As this mission is carried out by BC Hydro in the interest of ratepayers, all potential risks associated with it are applicable to ratepayers.

Topic: **Seasonal Generation Constraints and System Operations**

Reference: **Ince 1.7.5 and Ince 1.7.8**

2.19.0 Please confirm that BC Hydro has provided information related to minimum generation constraints for calendar year 2018, which indicates that incremental domestic energy brought into the BC Hydro system in the May-June time frame of that year would have resulted in increased spill or forced exports.

RESPONSE:

Generally, for the May to June 2018 load resource balance in calendar year 2018, the system was backed down to minimum levels for a significant portion of the time, with only periodic excursion above minimum generation. Any additional or incremental energy could have resulted in increased spill or forced spill during times when the system was backed down to minimum levels.

Topic: **Seasonal Generation Constraints and System Operations**

Reference: **Ince 1.7.5 and Ince 1.7.8**

2.20.0 Please confirm that this period of the year typically features low prices for exported market power.

RESPONSE:

BC Hydro assumes that "this period" in the question relates to the May-June period of the year.

Confirmed. Due to the Pacific Northwest power system being primarily hydro based, the peak freshet months of May-June typically will feature lower Mid-C market prices than at other times of the year. This is due to high freshet inflows and limited storage capability in the Pacific Northwest that result in high volumes of hydroelectric generation. Note that although the freshet and lower prices tend to occur in May and June, the timing of the freshet can vary and low prices can occur at other time periods.

For graphs showing historic average peak and off-peak electricity prices at Mid-C, please refer to Figure 12 in section 4.1 of Appendix D of the Transmission Service Freshet Rate Preliminary Evaluation Report for Year 1. A copy of that report has been included as Attachment 1 to this response.

BC Hydro
Power smart

Fred James
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

January 27, 2017

Ms. Laurel Ross
Acting Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Ross:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Transmission Service Freshet Rate
Preliminary Evaluation Report for Year 1 – Appendix D

BC Hydro attaches Appendix D of the Transmission Service Freshet Rate preliminary evaluation report for year one. This completes the report that was filed by BC Hydro on December 8, 2016.

For further information, please contact Gordon Doyle at 604-623-3815 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

(for) Fred James
Chief Regulatory Officer

ac/ma

Enclosure (1)

Transmission Service Freshet Rate

Preliminary Evaluation Report for Year 1

Appendix D

BC Hydro System Conditions during Freshet and Associated Management Strategies

Appendix D:

BC Hydro System Conditions during Freshet and Associated Management Strategies

1. Introduction

BC Hydro proposed the freshet rate pilot to, among other things, assist in the management of the freshet oversupply in the BC Hydro system by providing the option to:

- Increase the ability to import electricity during low priced periods;
- Reduce the volume of surplus energy being forced to export markets; and/or
- Reduce spill at BC Hydro facilities.

With the Commission approval of the freshet rate pilot, Commission Order No. G-17-16 included the following:

> Direction 4 as part of the evaluation process to address, and where appropriate, evaluate the following:
>
> (e) Detailed information as to the extent of the potential energy oversupply issue and BC Hydro's progress on other strategies it is pursuing to mitigate the issue; and
>
> Direction 6 stated that BC Hydro is to provide more clarity in its evaluations and provide more clarity as to the magnitude of the energy surplus during freshet and provide an estimate of its potential value.

This Appendix reviews the supply situation that exists during the freshet period and its impacts, as well as how BC Hydro manages the supply portfolio during the freshet period (sections 1 and 3), and the value of surplus to BC Hydro (section 4). It identifies other actions including the freshet rate that will extract further value from the supply portfolio (section 5).

In general, BC Hydro is of the view that it has over time acquired resources that were the most cost effective options when acquired inclusive of any freshet impacts, and that it manages the resulting supply portfolio in order to maximize the value of the resource portfolio inclusive of the freshet period.

BC Hydro continues to seek additional options, including the introduction of the freshet rate, to increase the value of the resource portfolio.

BC Hydro also concludes that the freshet supply situation and our limited ability to absorb further freshet energy results in very low values for freshet energy, and is expected to inform how BC Hydro will structure and evaluate future energy acquisition processes.

1. Background

1.1. Increase in Freshet Energy

Energy oversupply during freshet period is a seasonal condition in the BC Hydro system. Elevated generation in the freshet has always been the case because BC Hydro's resource portfolio is predominantly hydroelectric[1] with significant freshet inflows due to snowmelt. Approximately one half of the total annual system inflow volumes occur in the freshet, when system loads and market prices are low.

Where available, reservoir storage is used to capture the freshet inflows, which can then be used in later periods to serve load or for export when market prices are higher. System storage in Williston Reservoir on the Peace River and Kinbasket Reservoir on the Columbia River accounts for approximately 90 per cent of BC Hydro storage. Smaller reservoirs in the Bridge, Campbell, and Stave River systems, among others, also contribute to storage in the BC Hydro system. Figure 1 illustrates the imbalance between load and inflow for an average water year, and the role of system storage in shifting energy.

Over the past ten years BC Hydro has increased its portfolio of resources to meet its energy planning criteria under expected load growth by acquiring the most cost effective resources that were available at the time. A large number of these acquisitions were for energy from run-of-river facilities, the result of which has been an increase in must-take[2] energy of about 3,000 GWh during the freshet period, by 2018 (Figure 2).[3] At the same time, BC Hydro has been in a period with little or no net growth in freshet load, even though load growth was anticipated at the time the acquisitions were made.

The result has been an increase in the seasonal imbalance of load and resources in the freshet as demonstrated in Figure 3, which compares the monthly System Minimum Generation[2] to annual load for the year 2006 and 2018, as well as monthly System Minimum Energy level[4] for 2018. This figure shows that under average water conditions System Minimum Generation now exceeds demand in June whereas in 2006 significant flexibility existed in the system to facilitate the import of low price freshet

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1 BC Hydro resource portfolio mix by annual generation forecast for F2017 (BC Hydro owned and IPP): hydroelectric (91.0 per cent), biomass (4.5 per cent), wind (2.2 per cent), waste heat/municipal solid waste (0.5 per cent), solar (0.01 per cent), gas fired thermal (1.8 per cent).

2 Refer to section 1.3 for definitions.

3 Over the same period, there was minimal increase in freshet must take generation from BC Hydro's heritage resources (approximately 80 GWh increase due to facility upgrades).

4 System Minimum Energy level is minimum generation plus generation that must occur in order to avoid spill at Williston and Kinbasket (Freshet Shapeable Generation). Refer to section 1.3 for definitions.

energy from out of province. Additionally, System Minimum Energy now exceeds load in both June and July in an average water year. Key issues include the frequency that minimum generation exceeds load in the freshet, how often BC Hydro is able to export that energy or when it must be spilled, and what value the surplus energy has in the markets when it can be exported.

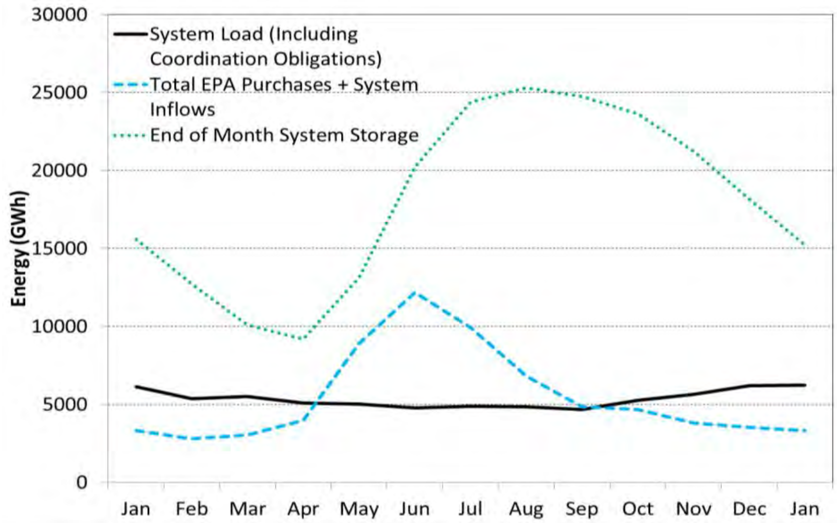

Figure 1 **Forecast 2018 Monthly Load in Comparison to System Inflow under average inflow conditions, and the effect on BC Hydro Storage**

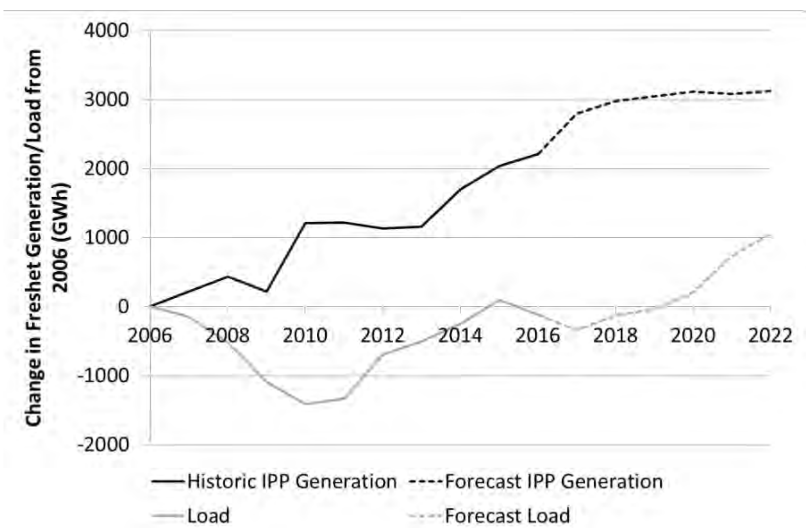

Figure 2 **Change in May-July Energy Volumes from 2006 for EPA Purchases[5] and BC Hydro Integrated System May – July Load**

[5] Forecast IPP generation is net of IPP energy that can be economically turned down during the freshet, thereby representing all must-take IPP energy and economic IPP energy. This reflects the IPP forecast filed in the 2016 RRA.

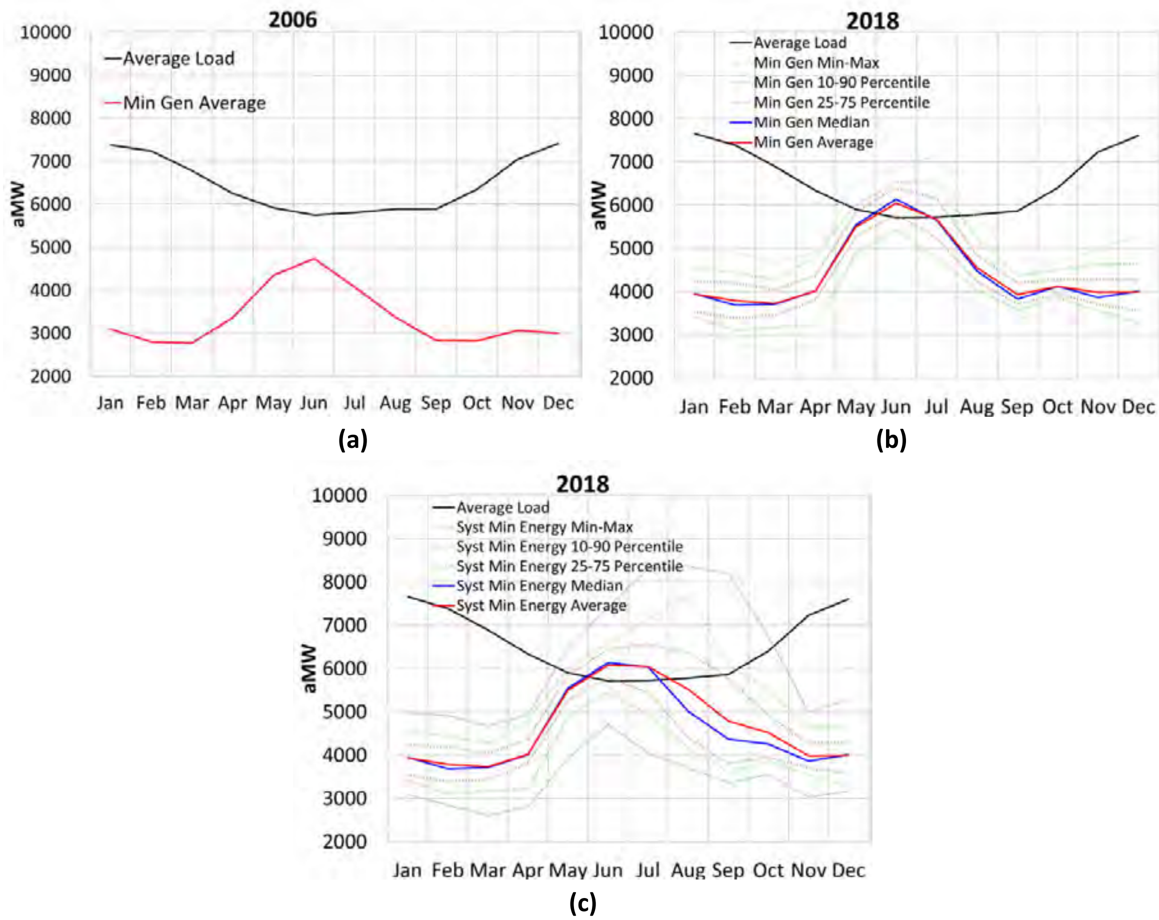

Figure 3 **(a) 2006 Minimum Generation[6] and Load under Average Inflow Conditions, (b) 2018 Minimum Generation and Load under Various Inflow Conditions, (c) 2018 System Minimum Energy and Load under Various Inflow Conditions**

1.2. System Operations

BC Hydro's operating strategy follows the same principles in the freshet period as in the rest of the year, with the objective of maximizing the consolidated net revenue from operations.[7] BC Hydro will shape generation into the highest value periods available within the limits of flexibility of the system. During the freshet, the flexibility to shape generation is less than at other times of the year; however, the objective of maximizing consolidated net revenue remains the same.

6 Minimum generation is modeled using all historic inflow sequences for the resource portfolio in year 2006 and 2018.

7 Consolidated refers to the combined activity of both BC Hydro (domestic) and Powerex (trade). BC Hydro will purchase energy to meet load when required, and will sell surplus energy. In contrast, Powerex buys energy for the purpose of reselling it into the market for profit. All of Powerex's net trade income goes to rate payers.

Over the winter and in preparation for the freshet, BC Hydro generates to draft its large reservoirs to make space to store freshet inflows. The operating strategy has BC Hydro's large system reservoirs drafted to levels that will balance the gains from keeping the reservoirs higher (head gains) against the cost (risk of spill), while considering market price and inflow uncertainties. While the benefits associated with head gains are almost exclusively economic, the costs associated with spill will include other factors such as incremental gate and spill chute wear, plunge pool erosion, and elevated total dissolved gas downstream that can be harmful to fish. While these other factors are not explicitly modeled, system operators will at times make adjustments to generation dispatch to mitigate these issues. This operating strategy typically results in projects with upstream storage operating at minimum generation across a significant portion of the freshet, and under average conditions results in a system spill risk of approximately 10 per cent.

Backing down large system reservoir generation to minimum means that much of the inflow is stored in the reservoir for later use in higher value periods, and the must-take energy from hydroelectric facilities with no storage is used to meet load. However, as part of the optimization of system operations, in some years (typically periods with higher than forecasted inflows) these facilities are required to generate above minimum in order to maintain an acceptable spill risk.

1.3. Definitions

This paper has already used some standard terms like *system minimum generation, system minimum energy* and *must-take energy*. These terms and others used to categorize the different components of freshet energy and spill are defined below and summarized in Figure 4.

> *Must-take energy* - energy that cannot be stored at the facility for later use (i.e., must be used immediately when it is available). It includes generation from BC Hydro and IPP resources with little or no storage, after consideration of any turn down rights BC Hydro has (refer to section 5.3 for details on turn down rights). It also includes generation from large storage basins required to meet local reliability requirement or water license commitments. At facilities with little or no storage, must-take energy increases significantly during the freshet due to increased inflow volumes, especially during years with high snowpack.

> *System Minimum Generation* - if the system is operating exclusively on must-take energy, then it is considered to be operating at *minimum generation*.

> *Freshet Shapeable Energy* - generation from large storage plants that is required within the freshet period to maintain an acceptable spill risk. This energy can be dispatched to higher value hours but must be generated during freshet.

> *System Minimum Energy* - is the sum of must-take and freshet shapeable energy. At times the system minimum energy is higher than system load, resulting in a *system surplus* for that time period. When this happens, BC Hydro is forced to either sell the surplus power to markets, or spill the energy.

System spill – spill that occurs when a system reservoir (Williston and/or Kinbasket) is either at or close to its normal full supply level and either:

- Inflows exceed the maximum generating capability of the hydroelectric power plant. Under these conditions, release of water through a spillway will be required to preserve the integrity of the hydroelectric facility; or

- System generation is required to be reduced due to limited transmission intertie export capacity. Under these conditions, generation output at specific projects must be reduced from full capacity and water is spilled.

Economic spill – spill that occurs when market prices are very low. Under these conditions, BC Hydro may reduce generation at some facilities, either to avoid exporting the surplus at a loss (i.e. if the market value is less than the wheeling cost), or to support additional imports (when market prices are negative), and spill the energy that could have been generated.

System
Minimum Energy Level

Must-Take Energy (This makes up System Minimum Generation level)		Freshet Shapeable Energy
Electricity Purchase Agreements	BC Hydro Resources	
EPA energy that BC Hydro must accept *i.e.* for EPAs with facilities that BC Hydro has take-or-pay contractual obligations to accept delivered energy (after consideration of applying turn down rights when they exist)	**Energy that is required to be generated immediately** *i.e.* generation required to either meet local reliability requirements, avoid immediate spills [at reservoirs with little or no available storage] or meet downstream release requirements	**Energy that is required to be generated during the freshet period to mitigate spill risk at projects** *i.e.* to reduce spill risk in later months, BC Hydro must generate some energy during the freshet period however this energy can be stored in large reservoirs and generated in higher value hours during the freshet

Figure 4 Components that make up BC Hydro System Minimum Energy

3. Magnitude of the Freshet Surplus and System Impacts

The increased freshet surplus over the last ten years has impacted both import/exports and system spill risk, and has resulted in:

- Growing volumes of forced exports;

- Reduced shaping capability within the freshet;

- Higher likelihood of hitting transmission intertie constraints, thus necessitating additional spill from system reservoirs; and
- Reduced capability to import electricity during low priced period.

This section will discuss the magnitude of the historical and forecast freshet surplus from 2006 to 2018 and the impacts it has had on the system.

3.1. Import/Export Impacts

From 2006 through 2018 (projected), there will have been about 3,000 GWh of additional must-take freshet energy added to the BC Hydro system, coupled with negligible load growth across the same period. This has shifted the load-resource balance in the freshet from a position where flexibility existed to import significant low priced freshet energy, to now being forced to export surplus energy into that same low priced market. Figure 5 shows actual historic average import and export levels during the freshet periods. These net exports are driven by a combination of must-take energy deliveries, shapeable energy and economically driven exports (high market price conditions). The high degree of year-over-year variability in the net export balances is due to the combination of shapeable energy (inflow driven), and economic exports (market driven). While highly variable, the data does show that:

- There is an overall trend towards higher net exports, particularly in the off-peak hours. This can be directly attributable to the significant increase in must-take energy over the last ten years combined with no net load growth during the freshet period (refer to Figure 2).
- There is a correlation between system inflows and average net exports across the freshet. This correlation is derived from both the combination of increased must-take energy and the tendency towards more shapeable energy in high inflow years.

The freshet period has been defined to extend from May through July for the Freshet Rate Pilot. On average, this period will have the highest system minimum generation levels, along with the lowest system loads. However, from an operational perspective, freshet conditions (high must-take energy in the BC Hydro system coupled with low price market conditions) will often extend from about mid-May through to early-July. In the first half of May must-take energy is ramping up with increasing inflows to the system, while in the second half of July external market prices are increasing with the combination of air-conditioning loads in the U.S. and receding regional inflows. As such, the month of June will typically be the critical period with a combination of a high freshet over-supply coupled with low external market prices.

Figure 6 shows the evolution of the system load-resource balance (i.e. net trade position) for the month of June for must-take resources under average inflow conditions. The graph shows that under average system conditions the potential for imports and forced exports has shifted in the last ten years from a flexibility to import about 1000 aMW to 400 aMW[8] of forced exports. Note that the addition of shapeable generation to Figure 6 would result in a larger level of forced exports in recent years. This shift in load-resource balance has had the following impact on import/export activity:

- Ten years ago, with net import flexibility in the freshet, the BC Hydro storage system was able to time shift low cost imported energy from the freshet to the upcoming fall and winter periods.
- By about 2010, the acquisition of must-take energy, along with no freshet load growth, had diminished this flexibility to near zero.
- By 2018, the acquisition of additional must-take energy is expected to result in about 400 aMW of surplus energy in June under average inflow conditions. Thus in this period this energy must be either exported (in both Heavy Load and Light Load Hours), or spilled from projects within the system.

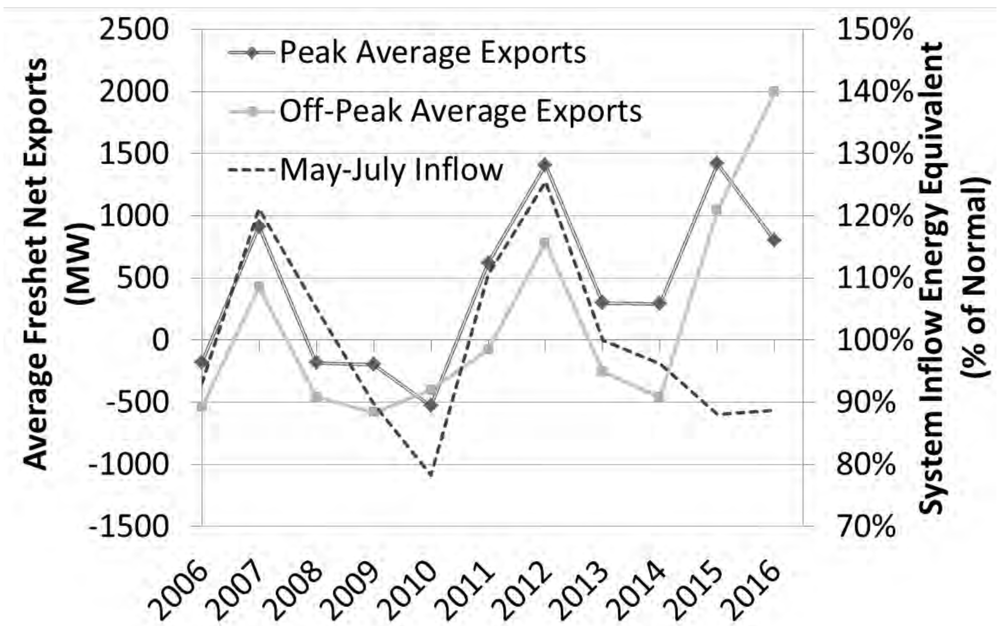

Figure 5 **Historic Actuals of Average Peak and Off-Peak Net Exports during Freshet (2006 to 2016)**

8 aMW represents *average MW*, which is total energy in a certain time period divided by number of hours in that time period. aMW can be converted to energy for a given period of time by multiplying by the number of hours. For example, 400 aMW in June is equal to 400 MW x 30 days x 24 hr/day = 288,000 MWh (288 GWh).

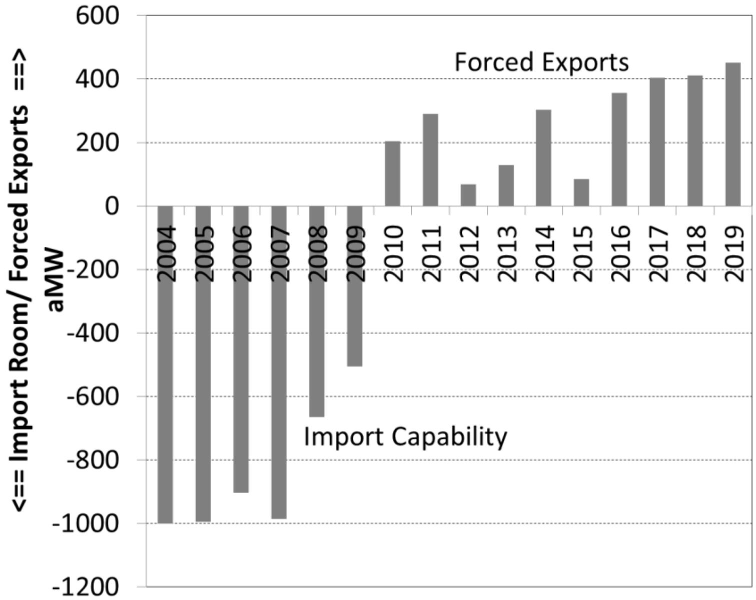

Figure 6 **Change from potential for imports to forced exports in June under average water conditions over time**[9]

3.2. System Spill Risk Impacts

As previously discussed, Figure 5 shows historic average imports and exports during the freshet for peak and off-peak periods. It shows the general trend over time of BC Hydro moving from a net import regime to a net export regime during the May-July period. This trend, while tied to the recent build in the must-take freshet energy, would not be expected to substantially change large basin freshet operations. Large basin plants within the freshet will still respond to market signals, with reduced releases during low price periods, and higher releases during higher priced periods. The key difference with the additional must-take volumes will be the overall resulting net export position. Under conditions where one or both large basins are threatened with spill, and must be ramped to high generation, transmission export limits will now become a greater impediment to sustained high generation from the large basin storage plants.

Figure 7 outlines a high inflow scenario where an additional 3,000 MW of generation is required from large basin storage to mitigate spill risk. This situation can materialize when there is a sharp increase in inflow (well above forecasted), due to high precipitation in the freshet months. In recent years examples of this significant increase in inflow include:

- 2007 Water Year (February to September):
    - March Seasonal Inflow forecast was 109 per cent of average.
    - Resulting Seasonal Inflow was about 118 per cent of average.

[9] Assumes production under average inflows for all facilities except for Kinbasket and Williston, which are assumed to run at minimum generation and store the remaining inflow. Forced exports = (system inflows + IPPs) minus (load + coordination agreement entitlement obligations + storage into Kinbasket and Williston).

  - The 9 per cent increase would be the energy equivalent of about 15 feet in Williston Reservoir.
- 2011 Water Year (February to September):
  - March Seasonal Inflow forecast was 99 per cent of average.
  - Resulting Seasonal Inflow was about 112 per cent of average.
  - The 13 per cent increase would be the energy equivalent of about 21 feet in Williston Reservoir.
- 2012 Water Year (February to September):
  - March Seasonal Inflow forecast was 106 per cent of average.
  - Resulting Seasonal Inflow was about 123 per cent of average.
  - The 17 per cent increase would be the energy equivalent of about 28 feet in Williston Reservoir.

Based on average loads and must-take energy around 2006, an increase in 3,000 MW of generation from the large basins (to avoid spill) would result in just over a 2,000 MW net export from the BC Hydro system. By 2018, with average loads and must-take energy shifting the base Load-Resource balance to a 400 aMW surplus position, an increase in 3,000 MW of generation from the large basins would result in about a 3,400 MW net export from the BC Hydro system. This level of export would however likely not be attainable due to export transmission limitations. As such, either generation from the large basins would need to be reduced (increasing spill at the projects), or generation from a must-take project within the BC Hydro system would need to be reduced, with the associated spill.

Under this condition there must either be an elevated risk of spill at the storage project due to inability to release from the large basin, or a deeper draft of system storage to mitigate the spill risk. System operators will be guided by risk neutral modeling[10] to determine the appropriate tradeoff between system head losses and spill risk.

The resulting physical operation of the storage basin would be expected to see some additional draft of storage, coupled with some increase in spill risk. The financial and environmental impacts of these operational changes have not been assessed; however, they are not expected to be substantial.

[10] Risk neutral modeling assumes each modeled possible outcomes is equally likely (i.e., it does not bias towards or against favourable or unfavourable outcomes).

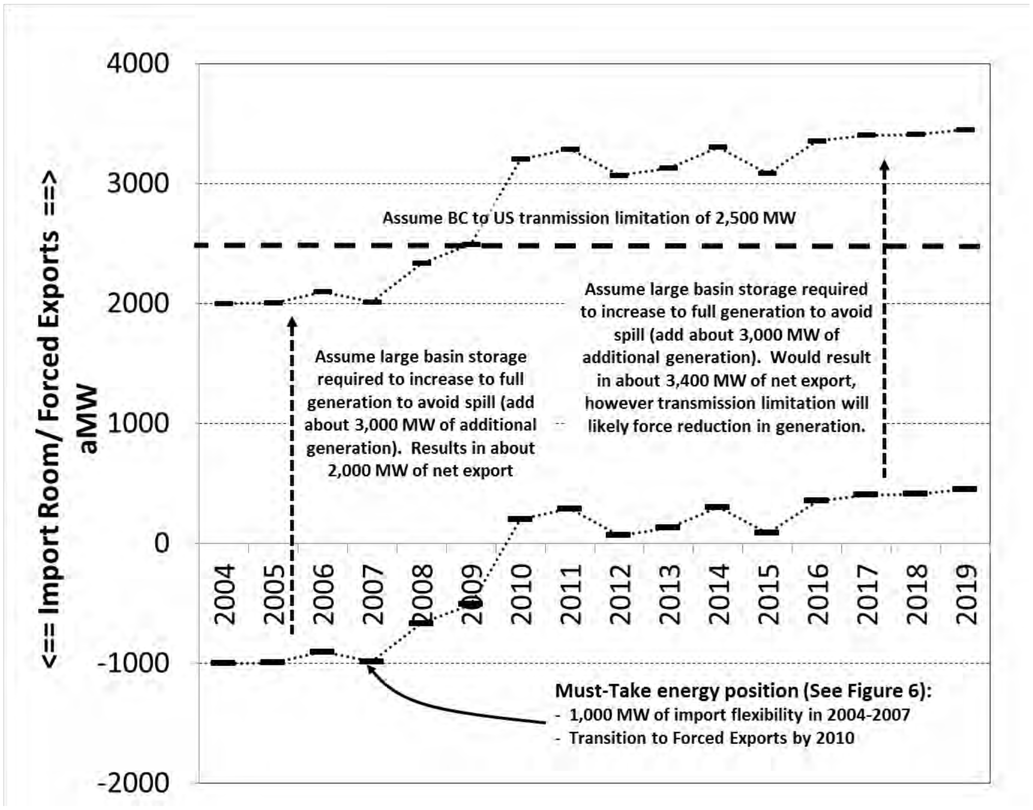

Figure 7 **Impact on Net Trade Position in June due to combination of must-take energy and large basin generation required to avoid spill (shapeable generation)**

3.3. Estimated Magnitude of Surplus

BC Hydro has estimated the magnitude of freshet surplus through a two stage, heuristic model,[11] for the BC Hydro system on an hourly basis from 2006 to 2016 (May through July). Figure 8 shows the hourly simulation results comparing system minimum energy and the load[12] for the BC Hydro integrated system for a single month (June 2016). It shows that the hourly system minimum energy exceeds the integrated system load in many hours, which results in a system surplus (i.e., when the shaded generation area is above the black load line).

These surplus quantities must either be exported or spilled. System surplus is exported when a net revenue gain would be realized and export capability exists. However, at times when market prices are

[11] A two stage heuristic model is a rules based model that solves the problem in two stages. The model first calculates the amount of must-take generation in each hour for the integrated system as well as monthly shapeable generation volumes. Shapeable generation volumes are based on historic actual operation (i.e., historic month end elevations are used). It then uses the difference between hourly must-take generation and load, as well as market prices, to determine the hourly timing for shapeable generation.

[12] The hourly B.C.-integrated system load includes FortisBC load is shown because BC Hydro operates Fortis' plants and the energy contribution from these plants is included as generation.

below the cost of wheeling and losses (approximately $7.50 CAD/MWh[13]), the energy is assumed to be spilled to avoid exports that would result in a financial loss on the export transaction.

Summing the hourly surplus across the entire freshet yields the total freshet generation surplus each year as shown in Figure 9. The surplus is broken out by exports and spill. It can be seen that surplus volumes are directly correlated to inflow volume during the freshet. Most of the spill in Figure 9 would be classified as economic spill as it occurred in order to avoid exports resulting in a financial loss. However, some of the spill also occurs because transmission line capacity was reached and no additional energy could be exported.

Figure 10 highlights the number of hours the system was calculated to be in surplus for each year. Similar to surplus volumes, significant variability exists between years due to variations in inflow; however, in 2013 and 2014, which were near average water years, 40 per cent or more of hours were in surplus while in 2006 and 2008, which had similar inflow levels, less than 20 per cent of hours were in surplus.

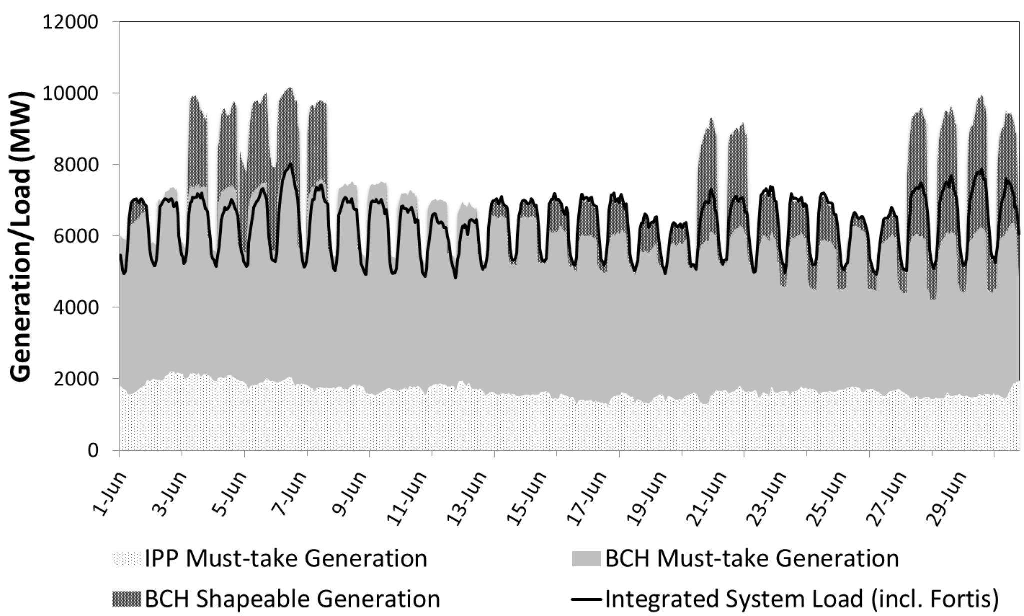

Figure 8 **Example of Simulated Must-take and Shapeable Generation for June 2016**

13 Assuming 1CAD = 0.75USD.

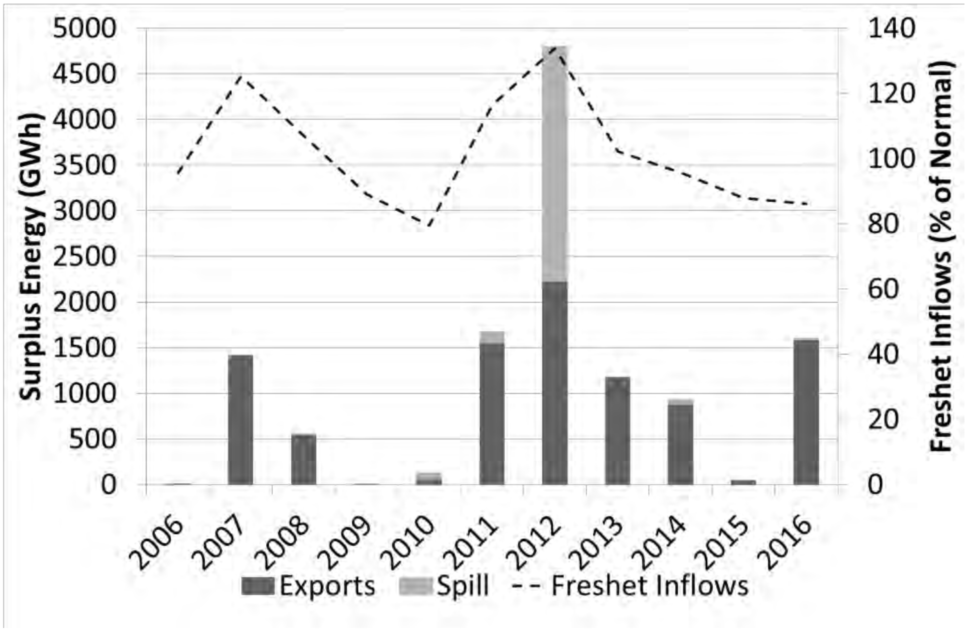

Figure 9 Calculated Surplus Generation Volumes during the Freshet for the BC Hydro Integrated System, Years 2006 to 2016

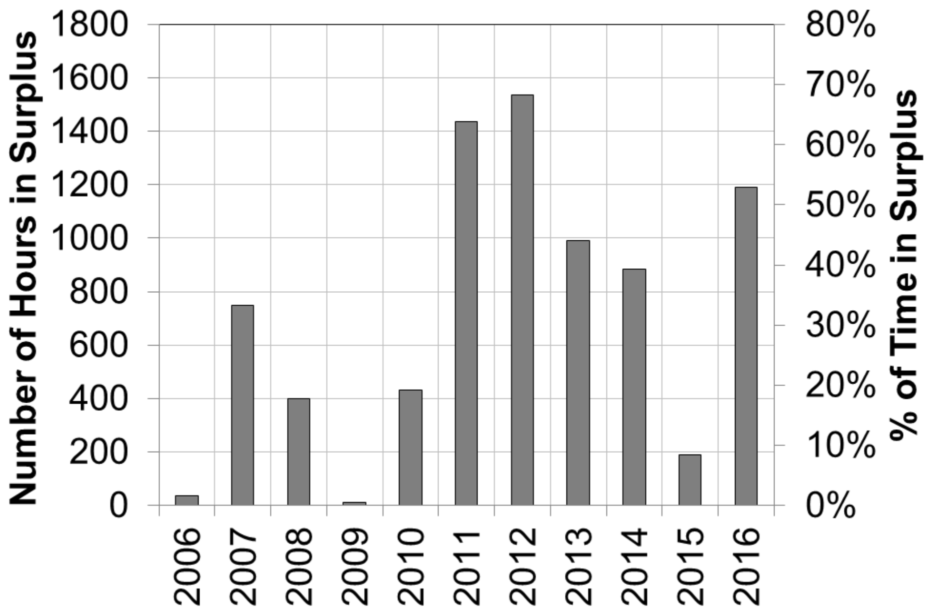

Figure 10 Calculated Number of Hours and Percent of time in Surplus during the Freshet for the BC Hydro Integrated System, Years 2006 to 2016

4. Value of Freshet Energy and Flexibility

4.1. Electricity market prices

The majority of the BC Hydro/Powerex electricity trade transactions takes place in, or passes through, the Mid Columbia (Mid-C) market located in the US Pacific Northwest. Prices at the Mid-C market are generally the lowest during the freshet period and have declined over the years and seen negative freshet prices at times in recent years, as can be seen in Figure 11. The Pacific Northwest also has freshet energy oversupply conditions similar to B.C. The oversupply is primarily due to heavy generation at US hydroelectric plants on the Columbia River (also driven by snowmelt runoffs) and low loads. Over the last ten years, the addition of about 5,000 MW of wind generation in the U.S. Pacific Northwest with large output during the spring together with production tax credits has further depressed the freshet prices (to sometimes negative prices during off-peak hours[14] of the freshet period).

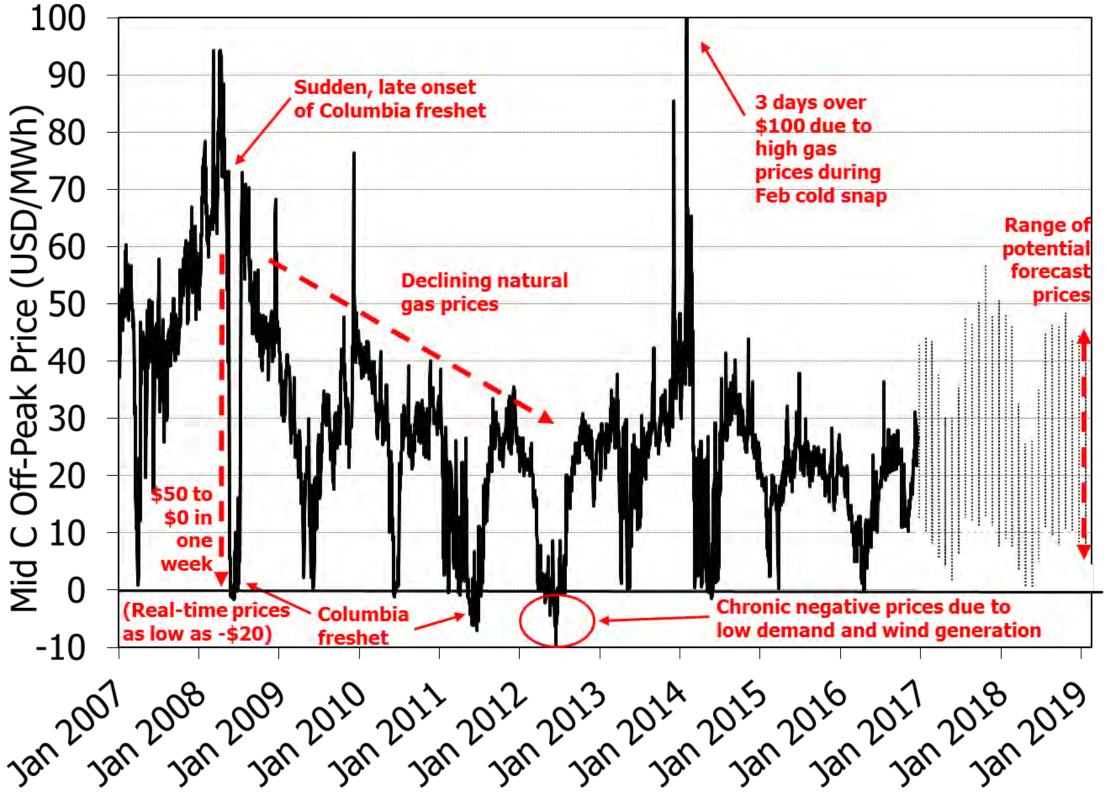

Figure 11 Mid-C Off-Peak Historic Daily and Forecast Monthly Index (Pre-Schedule) Prices (January 2007 to March 2019)

While the timing of the freshet period and the magnitude of freshet inflow varies from year to year, it is a recurring annual condition generally depressing prices to varying degree and duration whenever it

[14] Peak hours (i.e., heavy load hours) are the 16-hour period between 6 a.m. to 10 p.m. (Monday – Saturday) and off-peak hours are the eight-hour period from 10 p.m. to 6 a.m. (Monday – Saturday), and all day Sundays and holidays.

comes. It should be noted that while the lowest market prices don't always happen May through July, May through July is the period of highest system minimum generation in the BC Hydro system as shown in Figure 3.

Figure 12 below shows historical average monthly Mid-C peak and off-peak prices for the years 2006 to 2016. In most years the freshet period has the lowest prices, especially in off-peak periods. In 2015, the freshet inflows in the US Pacific Northwest arrived early, depressing prices as early as February. In dry years such as 2009, less hydroelectric generation in the Pacific Northwest leads to less depression of market prices, or depression for a shorter period of time.

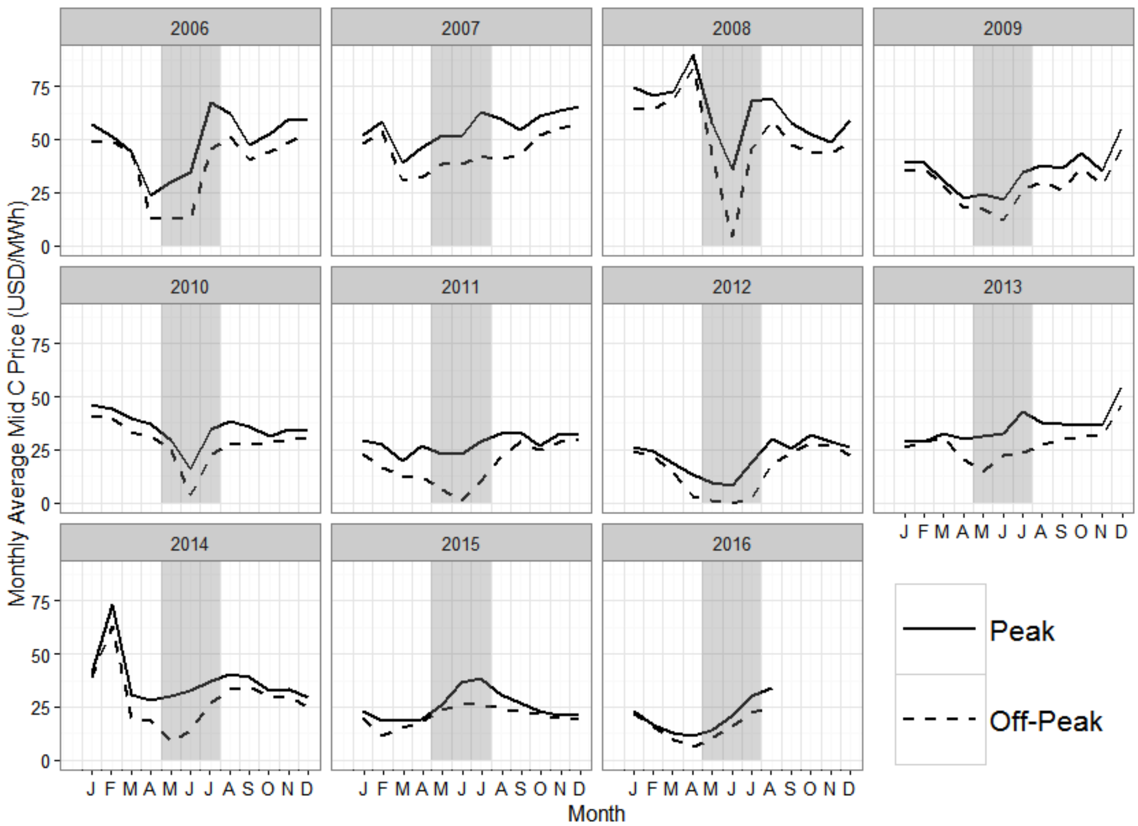

Figure 12 **Historic Monthly Average Peak and Off-Peak Electricity Prices at Mid-C ($US Nominal), 2006-2016**

4.2. Energy Valuation

The calculated surplus freshet energy quantities for the years 2006 to 2016 were valued as part of the same heuristic modelling described in section 3.3. Surplus energy that could be exported economically and physically (i.e., Mid-C prices were above wheeling costs and sufficient transmission capacity existed) were valued at the BC sell price while spill was given a value of zero.

Figure 13 shows the value of must-take surplus on a $/MWh basis. As expected, the surplus values are directly linked to freshet market prices; however, the average unit value of surplus must-take energy is consistently below average BC sell price. The average value shown in this figure has not been reduced to reflect (1) the opportunity cost associated with BC Hydro's reduced ability to import low cost or negatively priced electricity during freshet (especially during off-peak hours) and sell it for a higher price, either during peak hours or after the freshet, and (2) the potential capital or maintenance costs associated with high levels of spill.

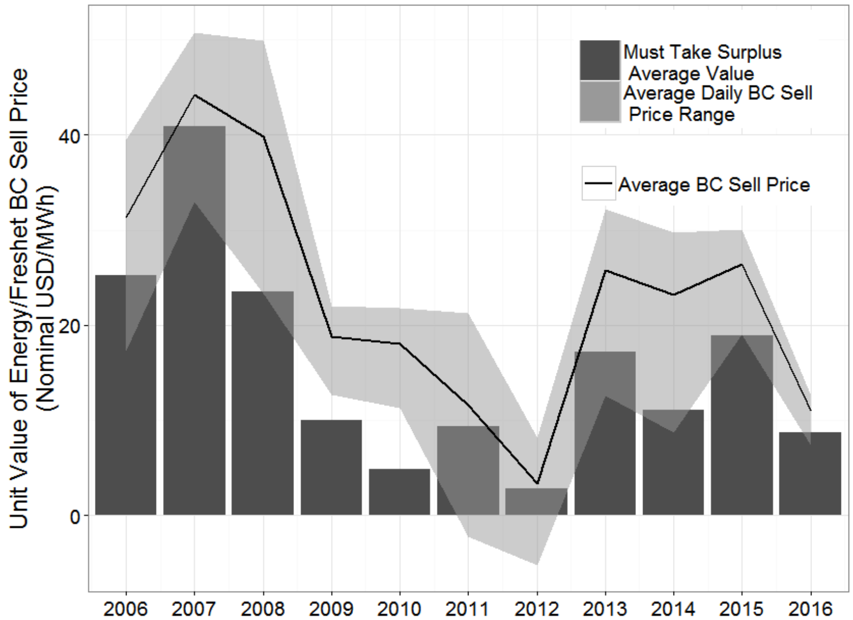

Figure 13 **Calculated unit value of historic freshet surplus generation for BC Hydro Integrated System, Years 2006 to 2016**

As previously discussed, with the significant increase in must-take generation in the system over the last ten years with little freshet load growth, the average June import room has diminished from about 1,000 aMW to an anticipated surplus of about 400 aMW (Figure 6). This has had significant impact on marketing of energy within the freshet, resulting in:

- The requirement that BC Hydro export the surplus into the same low priced power markets, and
- The loss of the market opportunity for BC Hydro to import low priced freshet energy from outside the province and carry this energy into the fall/winter period.

With the recent transition of the system to a forced export position (under System Minimum Generation conditions), this surplus must be sold (salvaged) as it is delivered. A reasonable estimate of the salvage value is based on the June sale price of approximately 15 CAD/MWh (including transmission costs).

- **Salvage value of 400 aMW of surplus exports (2018): 4.3MCAD**

400 aMW x 30 days x 24 h x 15 CAD/MWh = 4.3 MCAD

Prior to the procurement of large volumes of freshet must-take energy, BC Hydro would use system storage to absorb low priced freshet energy, and effectively release this energy in the fall/winter to capitalize on the seasonal price differential of energy. The estimated value of this lost marketing opportunity can be estimated using the following assumptions: (1) that October market prices are representative of the marginal value of energy in the BC Hydro system, and (2) the spread between June and October is indicative of the lost opportunity. This spread is typically about 10 CAD/MWh. As such, an order of magnitude estimate of the lost energy shaping opportunity for 1,000 aMW (72 GWh) of June import flexibility would be about 7.2 MCAD.

As noted previously, it is expected that the most significant oversupply condition during the freshet occurs in June, but typically there are impacts in the second half of May and as well as early July. As such, we may estimate that the overall financial impact of the loss of import room is about twice what is shown above.

5. Mitigation Measures Status Update

Over the next decade, we expect the market prices during freshet to stay low (below $25 USD/MWh levelized [$2016][15]), and freshet energy in our system to continue to grow. Site C, while being the most cost effective option to provide energy and capacity to our system, will also contribute additional freshet energy, though small relative to its annual energy production due to upstream regulation provided by Williston and Peace Canyon reservoirs. As a result, we expect the tools to optimize operations during freshet would continue to result in benefits to the system.

BC Hydro is implementing a number of strategies to increase the value of the freshet energy from its portfolio of resources. In addition to optimizing the system through operational measures, we recognize that there is value in strategically limiting must-take freshet energy or increasing freshet load. BC Hydro's acquisition strategy going forward needs to reflect the low value of incremental freshet energy and the relatively higher value of resources with seasonal storage capability.

In addition to the Freshet Rate Pilot, BC Hydro has pursued a number of these actions or strategies as described below:

5.1. System Operation Measures

As discussed above, the large reservoirs in the BC Hydro system are drafted to absorb freshet inflows while maintaining minimum generation. As must-take generation has increased over the last ten years, drafts at the large basins have been adjusted to account for the increases in must-take energy, and reduction in low cost imports. However, these reservoirs cannot fully capture all the must-take energy on an hour-by-hour or daily basis due to real time operating constraints and minimum generation required.

15 Based on ABB Group Spring 2016 WECC Power Reference Case Mid Columbia price forecast.

5.2. IPP Time of Delivery Adjustments

Many of BC Hydro's IPP Electricity Purchase Agreements include a provision that adjusts the IPP payment price for energy volumes depending on the period of the day (super-peak[16], peak and off-peak) and the month delivery. For example, this provision was included in the standard form Electricity Purchase Agreements for the Fiscal 2006 Open Call for Power, the Clean Power Call and the Standing Offer Program. This provision is intended to encourage IPPs to build and operate projects that deliver energy at times which better meet our system need. Figure 14 below shows our current monthly time of delivery price multipliers provided in the Standing Offer Program standard form Electricity Purchase Agreement. The lower freshet multipliers shown in Figure 14 reflect the lower value BC Hydro places on freshet deliveries. In comparison, energy delivered during winter months in super-peak hours receives the highest adjustments. The time of delivery adjustment table is being reviewed with the aim to incent projects with generation profiles that better match current system need.

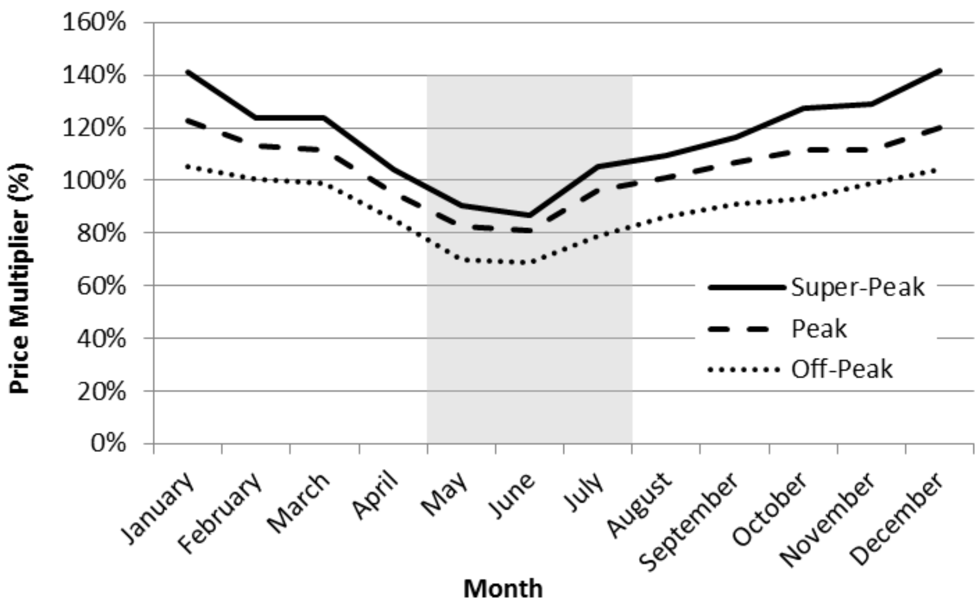

Figure 14 **Monthly Time of Delivery Price Multiplier for Standing Offer Program standard form Electricity Purchase Agreement (as of December 1, 2016)**

5.3. IPP Turn Downs

Many of BC Hydro's IPP Electricity Purchase Agreements include a provision that provides BC Hydro with the right to request an IPP to turn down or reduce its generation output for a certain period of time, subject to the operating constraints of the generating facility. During a turn down, BC Hydro avoids the

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16 In the time of delivery adjustments, super-peak hours fall in the four-hour period from 4 p.m. to 8 p.m. (Monday – Saturday), peak hours are the 12-hour period from 6 a.m. to 4 p.m. and 8 p.m. to 10 p.m. (Monday – Saturday) and off-peak hours are the eight-hour period from 10 p.m. to 6 a.m. (Monday – Saturday), and all day Sunday.

variable cost of generation. In the case of a gas-fired or biomass generating facility, a large portion of the variable cost of generation is associated with fuel. In contrast, wind and run-of-river generating facilities have much lower variable costs of generation because they use natural resources for power generation and do not incur fuel costs and thus, their variable costs of generation are low. As such, BC Hydro has been focusing on turn downs for gas-fired and biomass generating facilities because of greater cost savings.

When a biomass generating facility is turned down, the IPP saves the cost of the fuel that would otherwise be used. Under the Electricity Purchase Agreement, these fuel cost savings are passed onto BC Hydro in the form of a lower unit energy price which is intended to cover only the IPP's fixed cost of generation during the period that the facility is turned down.

By exercising its turn down right under an Electricity Purchase Agreement, BC Hydro may be able to realize cost savings and reduce the amount of surplus energy in the system and avoid exports or spill caused by additional must-take generation. In 2016, BC Hydro had 42 Electricity Purchase Agreements with economic turndown rights for resources on the integrated system. These turn down provisions enabled BC Hydro to reduce generation output from IPP facilities by about 770 GWh during freshet, resulting in cost savings to BC Hydro. Of the generation reduced, gas fired and biomass generation facilities contributed 70 per cent and 30 per cent, respectively, with turn-down provisions exercised at 11 Biomass projects and one thermal project. No IPP wind, energy recovery generation, municipal solid waste, hydro, or solar projects were curtailed for economic reasons in 2016. On a going forward basis, BC Hydro intends to include a turn down provision in Electricity Purchase Agreements to provide flexibility that is beneficial in periods of oversupply.

As well, within the 2007 Electricity Purchase Agreement between BC Hydro and Rio Tinto Alcan, provisions exist to reduce generation from the Kemano Project during the freshet. BC Hydro has used this flexibility to its practical extent. Key issues that preclude BC Hydro from using this flexibility further or more often include (1) restrictions due to downstream flood risk, and (2) high likelihood that any energy stored into the Nechako Reservoir (already paid for by BC Hydro) would be spilled.

5.4. Standing Offer Program Optimization

The Standing Offer Program is undergoing a review, referred to as the "SOP Optimization process", to ensure that the acquisition program reflects future system needs and is aligned with BC Hydro's 10 Year Rates Plan. The SOP Optimization process was initiated as part of collaboration between Clean Energy BC, First Nations, the Ministry of Energy and Mines, the Ministry of Forests, Lands and Natural Resource Operations, and BC Hydro.

The scope of the SOP Optimization process involves a range of activities, including an assessment of how BC Hydro can refine the program to encourage the development of resources that will provide dependable capacity to BC Hydro's system, and projects that will have an energy delivery profile that better matches BC Hydro's system needs.

These activities within the SOP Optimization process will lead to improvements in the program that will more closely align any new incremental surplus freshet energy with its value.

5.5. Conclusions

This paper has shown that over the past ten years in particular, BC Hydro's system operations have changed as a significant addition of clean variable energy has been acquired in a period with little load growth and an economic downturn in several commodity sectors. The system that BC Hydro has built, acquired and committed to is a sunk cost and BC Hydro has been operating its system to optimize the value of the available resources.

Over the years, BC Hydro's system has transitioned from a net importing position to a net exporting position during freshet. System flexibility that allows for trade benefits has been eroding and our ability to take in more freshet energy is increasingly limited, with about 40 per cent of the hours over freshet period being in surplus under average water condition. The average value of this surplus is lower than market price because of transmission costs and, at times, spill (due to export transmission constraints or market prices that are uneconomic for export).

While BC Hydro has undertaken competitive acquisition programs and acquired the most cost effective resources that were available at the time including during the freshet period, it is now in a position that it needs to evolve how to value additional acquisitions. Additionally, BC Hydro continues to seek additional options, including the introduction of the freshet rate, to increase the value of the resource portfolio.

David Ince Information Request No. **2.21.0** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 2
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

Topic: **Seasonal Generation Constraints and System Operations**

Reference: **Ince 1.7.5 and Ince 1.7.8**

2.21.0 Does BC Hydro expect the current pattern of low market prices during the spring freshet to persist into the foreseeable future? At a high-level, please discuss the generation resource mix/makeup of the US Pacific Northwest, the timing of the freshet (and wind-based electricity supply) in this region, and how this translates into seasonal market prices.

RESPONSE:

BC Hydro expects that the current pattern of low market prices during the spring freshet will persist into the future. The lower market prices in the freshet are usually a result of lower regional loads and generation mix during those time periods which typically see an increase in hydro generation and wind production.

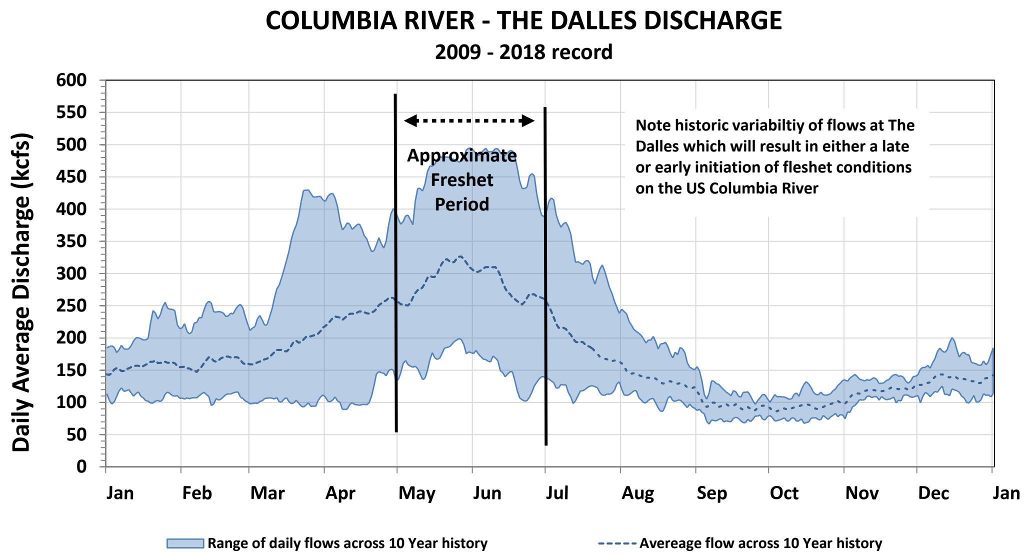
BC Hydro has provided the following information below:

1. **The generation mix in the Pacific Northwest;**
2. **A graph of historical physical flows at The Dalles on the Columbia River near Portland. The flows are a proxy of the hydro based energy production on the Columbia river; and**
3. **A graph of wind generation within the Bonneville Power Authority Balancing Authority across the period between 2016 and 2018.**

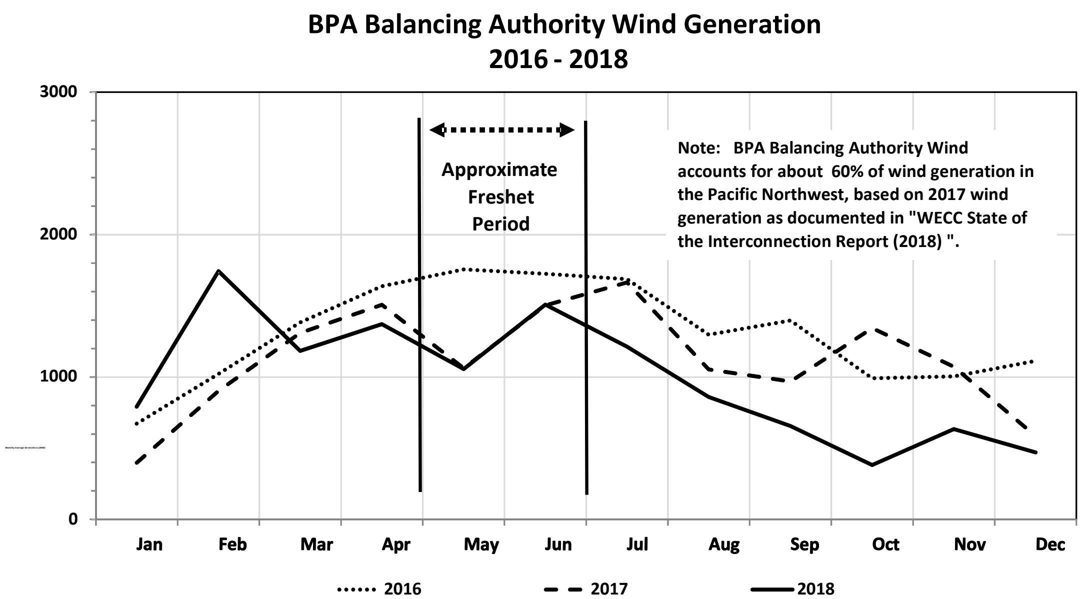
2017 Generation Mix (Pacific Northwest)[1]

Generation Type	Energy Production (GWh)
Hydro	130,710
Natural Gas	26,437
Wind	14,659
Coal	7,238
Solar	660
Geothermal	259
Other	3,604
Total	191,696

1. WECC State of the Interconnection Report (2018) provides for each Balancing Authority the annual energy production from each generation type. BC Hydro has aggregated the information for the following Pacific Northwest Balancing Authorities: AVA, BPAT, CHPD, DOPD, IPCO, PACW, PGE, PSEI, SCL, TPWR.



COLUMBIA RIVER - THE DALLES DISCHARGE
2009 - 2018 record
Daily Average Discharge (kcfs)
600
550
500
450
400
350
300
250
200
150
100
50
0
Approximate Freshet Period
Note historic variabiltiy of flows at The Dalles which will result in either a late or early initiation of fleshet conditions on the US Columbia River
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Jan
Range of daily flows across 10 Year history
Avereage flow across 10 Year history



BPA Balancing Authority Wind Generation
2016 - 2018
3000
2000
1000
0
Approximate Freshet Period
Note: BPA Balancing Authority Wind accounts for about 60% of wind generation in the Pacific Northwest, based on 2017 wind generation as documented in "WECC State of the Interconnection Report (2018) ".
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
2016
2017
2018

David Ince Information Request No. **2.22.0** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

Topic: **Seasonal Generation Constraints and System Operations**

Reference: **Ince 1.7.5 and Ince 1.7.8**

2.22.0 Please confirm that as indicated in the response to Ince IR 1.7.8, the forced spill/export situation during the freshet period is forecast to be worse in the year 2020.

RESPONSE:

In general, the amount of forced exports and spill tends to be larger in years with high freshet inflow volumes and tends to be smaller in drier years. However, forced exports and spills are also highly dependent on the daily rate of melt and weather conditions throughout the freshet months.

The 2020 forecast cannot be directly compared to 2018 actuals to determine if the forecast forced export or spill is changing.

Topic: **Seasonal Generation Constraints and System Operations**

Reference: **Ince 1.7.5 and Ince 1.7.8**

2.23.0 Please provide a chart in the same format, that in addition to the water situation in 2018 and forecast 2020, also provides the distribution for the 45 historical weather sequences used in BC Hydro's energy studies. That is, assuming BC Hydro's forecast demand requirements for each of calendar years 2018 and 2020, replicate the charts provided in the response to IRs 1.7.5 and 1.7.8 (feather duster chart format). Specifically, provide the charts in the IRs referenced above, for all water years 1973 to 2017 inclusive as a series of lines on a single chart for each of calendar years 2018 and 2020.

RESPONSE:

The requested information is not currently available and BC Hydro estimates it would take a number of days of working time to complete the task. Further, the monthly graphs would not capture any of the daily variability, which is indicative of forced exports and spill, as described to BC Hydro's response to INCE IR 2.22.0. As such, BC Hydro respectfully declines to provide the requested information.

Topic: **Seasonal Generation Constraints and System Operations**

Reference: **Ince 1.7.5 and Ince 1.7.8**

2.24.0 Given the above analysis, what percentage of incremental domestic energy is BC Hydro expected to be able to use for calendar years 2018 and 2020, by month, displayed in tabular format. That is, for each of the years 2018 and 2020, what percentage (based on inflows in water years 1973 to 2017 inclusive) of additional domestic energy would be absorbed/useful in the BC Hydro system, and what percentage would result in a mandatory spill or forced export. Monthly resolution please.

RESPONSE:

This response also provides BC Hydro's response to INCE IRs 2.25 and 2.26.

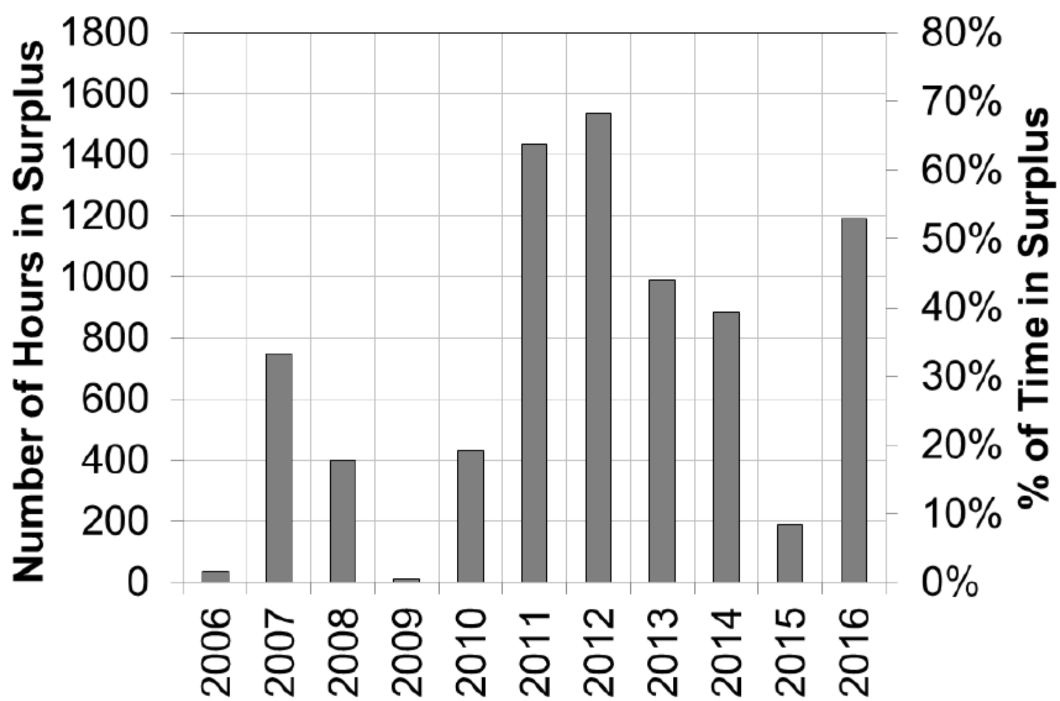
BC Hydro is not clear as to the meaning of "incremental domestic energy".

BC Hydro is also not clear what the intervener means when stating "energy… BC Hydro expected to be *able to use*". BC Hydro could potentially use energy to serve load, for export, or for storage.

For periods outside of the freshet, BC Hydro has not examined the probability that it would be able to absorb additional energy in the system without incurring mandatory spill or forced export. It is anticipated however that the probability would be at or near 100 per cent, given the flexibility within the BC Hydro system to operate at low generation levels.

BC Hydro has examined in detail the issue of the freshet surplus in Appendix D of the report 'Transmission Service Freshet Rate – Preliminary Evaluation Report for Year 1'. Figure 10 from the report is reproduced below and shows that the conditions vary greatly each year due to variations in system inflows, and the amount of additional energy that could be absorbed by the system is difficult to generalize.

Calculated Number of Hours and Percent of Time in Surplus during the Freshet for the BC Hydro Integrated System, Calendar Years 2006 to 2016



Topic: **Seasonal Generation Constraints and System Operations**

Reference: **Ince 1.7.5 and Ince 1.7.8**

2.25.0 Please confirm that any incremental domestic energy brought into the BC Hydro system in December 2020 will have a close to 100% probability of being used/useful for domestic consumption (sales).

RESPONSE:

Please refer to BC Hydro's response to INCE IR 2.24.0 which explains that outside of the freshet, additional energy has a high probability of being absorbed by the system.

Topic: **Seasonal Generation Constraints and System Operations**

Reference: **Ince 1.7.5 and Ince 1.7.8**

2.26.0 Please confirm that any incremental domestic energy brought into the BC Hydro system in June 2020 will have less than a 50% probability of being used/useful for domestic consumption (sales).

RESPONSE:

Please refer to BC Hydro's response to INCE IR 2.24 which explains that freshet conditions vary significantly from year to year and it is difficult to make a general statement about the probability that additional energy can be absorbed by the system.

Reference: BC Hydro 2019/20 – 2021/22 Service Plan:

2.27.0 Regarding BC Hydro's 2/3 share of the Waneta hydro electricity facility: does the monthly contractual energy available to BC Hydro from this asset, differ substantially from the remaining 1/3 share?

RESPONSE:

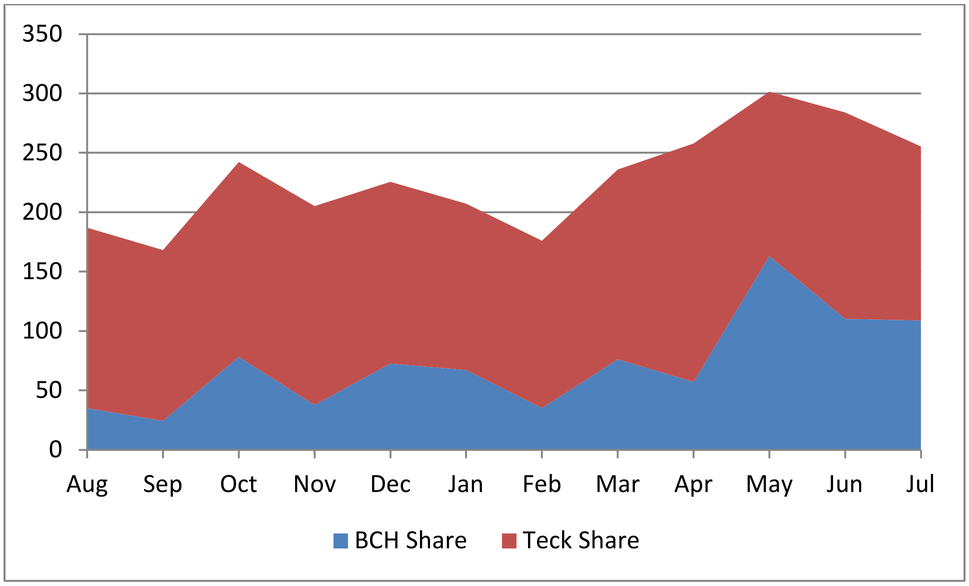
This response also provides BC Hydro's response to INCE IR 2.28.0.

As part of the Waneta 2017 Transaction, BC Hydro and Teck entered into the Waneta Lease Agreement that provides Teck with a share of the contractual energy attributable to Waneta which is based on the Canal Plant Agreement (CPA) entitlement energy. Please refer to section 3.2.4 of the Waneta 2017 Transaction Application for a more detailed summary of the Waneta Lease Agreement.[1]

Under the Waneta 2017 Transaction, Teck effectively maintains its two-thirds interest in Waneta for the duration of the lease subject to the energy-capacity swap that was agreed to by the parties in the Waneta 2010 Transaction, and maintained in the Waneta 2017 Transaction. As such, while BC Hydro owns the entire Waneta facility, BC Hydro does not have an interest in the two-thirds share of the entitlement energy covered by the Waneta Lease Agreement and the entitlement energy available to BC Hydro is approximately equal to a one-third share, subject to the energy-capacity swap. Please refer to section 3.2.5.5 of the Waneta 2017 Transaction Application for a description of how energy and capacity are provided to BC Hydro and Teck (link provided in the footnote).

The following figure shows the monthly CPA entitlement energy from Waneta as allocated between BC Hydro and Teck in units of gigawatt hours (GWh). The entitlements do not change on an annual basis unless a redetermination occurs. As such, the figure below is representative of the entitlements for the past five years. It is noted that the allocations vary by month and are not exactly one-third and two-thirds as a function of the energy-capacity swap referenced above.

[1] **2017 Waneta Transaction Application: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/waneta-2017-transaction-application.pdf**



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B-13</td></tr>
</table>

Reference: BC Hydro 2019/20 – 2021/22 Service Plan:

2.28.0 Please provide a monthly energy profile for the last 5 years indicating overall Waneta electricity production, BC Hydro's share, and remaining.

RESPONSE:

Please refer to BC Hydro's response to INCE IR 2.27.0.

Topic: **Operations Costs**

Reference: **Gjoshe 1.5.2:**

2.29.0 Please explain why Power Smart and Integrated Planning groups are not integrated as a single business unit with the objective of providing the lowest cost overall electricity supply to the corporation? Would such a merger result in synergies in terms of cooperation/coordination during the energy and capacity planning processes?

RESPONSE:

Please refer to BC Hydro's response to BCSEA IR 1.1.1, where we explain why the Conservation and Energy Management KBU is part of the People, Customer, Corporate Affairs Business Group.

As discussed in BC Hydro's response to BCSEA IR 1.1.5, there is a close working relationship between the Integrated Planning Business Group and the Conservation and Energy Management KBU, including during the energy and capacity planning process.

Reference: Province of British Columbia Mandate Letter dated February 21, 2019:

"The Government is adopting and implementing the United Nations Declaration of the Rights of Indigenous Peoples (UNDRIP), and the Calls to Action of the Truth and Reconciliation Commission (TRC), demonstrating our support for true and lasting reconciliation with Indigenous Peoples. All public sector organizations are expected to incorporate the UNDRIP and TRC within their specific mandate and context. Additionally, in May 2018, the Government released 10 Draft Principles to Guide the Province's Relationship with Indigenous peoples, which serves as a guide for all public sector organizations as we continue to build relationships with Indigenous communities based on respect and recognition of inherent rights;

While Government has already taken steps towards achieving our legislated carbon reduction targets, much remains to be done. Our new climate strategy will outline significant GHG reduction measures in 2019/20 while supporting our program and service objectives through economic growth powered by clean, renewable energy, supported by technological innovation. Please ensure your organization's operations align with Government's new climate plan;"

2.30.0 Please discuss the processes of costing and then acheiving the above Mandate Letter items.

RESPONSE:

UNDRIP and Calls to Action of the TRC

BC Hydro has and will continue to make reconciliation with Indigenous peoples a priority as a company. We believe the actions BC Hydro has taken in recent years have advanced reconciliation and have contributed to the incorporation of the UNDRIP and Calls to Action of the TRC into our business. An example of this is the company's Statement of Indigenous Principles which was developed in 2015 and is provided in BC Hydro's response to ZONE II RPG IR 1.12.1.

BC Hydro believes that incorporating the UNDRIP and the Calls to Action of the TRC is a long-term commitment to reconciliation, evolving as we work jointly with First Nation communities.

In the near-term, BC Hydro has not identified any incremental costs associated with the implementation of the UNDRIP and Calls to Action of the TRC. In the

future, budgets will be established as required and costs allocated using appropriate mechanisms and approval processes.

Phase 2 of the Comprehensive Review may provide some direction with respect to incorporating the UNDRIP and TRC into our business. Specifically, Phase 2 includes a focus on future opportunities or new roles for Indigenous Nations in the energy sector. It is possible that some of the work associated with this stream may have budgetary implications, and these will be factored into future revenue requirements as appropriate.

New Climate Strategy – CleanBC

The Government of B.C.'s new climate plan, CleanBC, was released in December 2018. The plan sets out a strategy for achieving 75 per cent of the greenhouse gas emission reductions that are required to meet the legislated 2030 emission target. Key elements of the plan include fuel-switching to clean electricity for transportation, industry and buildings.

The Comprehensive Review will develop recommendations for how BC Hydro can help meet British Columbia's legislated 2030, 2040, and 2050 greenhouse gas reduction targets in a manner that ensures BC Hydro sustainability in the future for the benefit of British Columbians. The Comprehensive Review will examine the role of BC Hydro in encouraging fuel switching to clean electricity as an alternative to fossil fuels, as well as changes that may be needed to ensure that customers can access clean electricity from the grid in an efficient, cost-effective, and timely manner.

It is possible that some of this work may have budgetary implications, and these will be factored into future revenue requirements as appropriate.

Please refer to Attachment 1 to BC Hydro's response to CEC IR 2.132.1 for a copy of the Terms of Reference for Phase 2 of the Comprehensive Review.

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Topic: **PRES Project**

References: **Ince IR 1.6.14 and 2019/20 – 2021/22 Service Plan: 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.

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."

2.31.0 Please confirm the reason why BC Hydro is not considering gas-fired generation solutions in the Peace Region to service incremental gas production demands, as stated in the response to Ince IR 1.6.14, is that this generation would result in the exceedance of the overall 93% clean target.

RESPONSE:

Not confirmed. The overall 93 per cent clean target was one aspect considered in determining how to serve incremental gas production demands but it was not the only consideration.

BC Hydro analysed multiple generation alternatives as capacity alternatives to the Peace Region Electricity Supply (PRES) project, including combined cycle gas-fired turbine (CCGT) generation, simple cycle gas-fired turbine (SCGT) generation, gas-fired generation with transmission reinforcement, and wind power generation backed with a SCGT plant.

At the time, two of these four gas-fired generation alternatives would have exceeded the 93 per cent clean target. The other two would have been within the 7 per cent remaining headroom for gas-fired generation. However, the estimated cost of all four gas-fired generation alternatives was higher than the estimated cost of the leading transmission alternative at the time.

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Topic: **PRES Project**

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2.32.0 The table in the Service Plan indicates a forecast Clean Energy percentage of 97.6% for Fiscal 2019. Please indicate the actual percentage for Fiscal 2019. Has recent information, subsequent to the issuance of the Service Plan, changed the forecast for subsequent years?

RESPONSE:

BC Hydro's 2018/19 Annual Service Plan Report, published in July 2019, reports on our year-end results against the performance measure targets set out in the 2018/19-2020/21 Service Plan. The actual fiscal 2019 Clean Energy percentage was 97.8 per cent.

The 2018/19 Annual Service Plan, published after the 2018/19-2020/21 Service Plan document, continues to list the Clean Energy 2019/20 and 2020/21 performance measure targets as 93.0 per cent, which is the minimum set out in the *Clean Energy Act.* These performance measure targets are consistent with those listed in 2018/19-2020/21 Service Plan, published in February 2018.

Topic: **PRES Project**

References: **Ince IR 1.6.14 and 2019/20 – 2021/22 Service Plan: 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.

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."

2.33.0 Please confirm that the Clean Energy target percentage is still 93%. How much headroom (expressed as annual GWh) was there in actual Fiscal 2019, relative to the target percentage? How much headroom (in GWh) is there in the gap between the expected 98% and the target 93%? Assuming an 80% load factor, what does the energy headroom translate to in terms of average annual MW?

RESPONSE:

BC Hydro confirms that the energy objective set out in the *Clean Energy Act* is to generate at least 93 per cent of the electricity in British Columbia from clean or renewable resources.

BC Hydro interprets the term headroom in the information request to refer to the difference between the maximum amount of non-clean electricity that could have been generated while still meeting the 93 per cent clean energy objective, and the actual non-clean generation in fiscal 2019.

In fiscal 2019, BC Hydro generated or acquired 56,300 GWh of electricity from resources in British Columbia. Of this, 54,900 GWh or 97.5 per cent was from clean or renewable resources, while 1,400 GWh was from non-clean resources. The clean generation percentage would have been 93 per cent had the non-clean generation been 3,900 GWh, with a corresponding decrease in clean generation that kept the total generation volume unchanged. The difference of 2,500 GWh translates into 360 average annual MW assuming a load factor of 80 per cent.

Topic: **Miscellaneous**

Reference: **Ince IR 1.3.5**

2.34.0 Please estimate the value of one foot of water at each of Williston and Kinbasket at an assumed value of power of $C30/MWh.

RESPONSE:

BC Hydro interprets the question as asking how much energy is in a foot of water at Williston and Kinbasket reservoirs, and then to multiply that energy volume by $30/MWh. The energy content varies by elevation.

BC Hydro does not disclose energy content by elevation as this information could be used to model BC Hydro's system to enable third parties to predict BC Hydro's import and export requirements. Disclosure of the information could reasonably be expected to harm ratepayers.

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Topic: **Miscellaneous**

Reference: **Ince 1.4.1**

2.35.0 Please confirm that approximately 160 residential accounts and a single transmission account (the Red Chris mine) are served by BC Hydro via. the Northwest Transmission Line/Iskut Extension.

RESPONSE:

According the fiscal 2019 billed sales for the Eddontenajon community there are 168 total customers, of which 136 are residential accounts. The Red Chris mine is the only transmission account served via the Northwest Transmission Line (NTL).

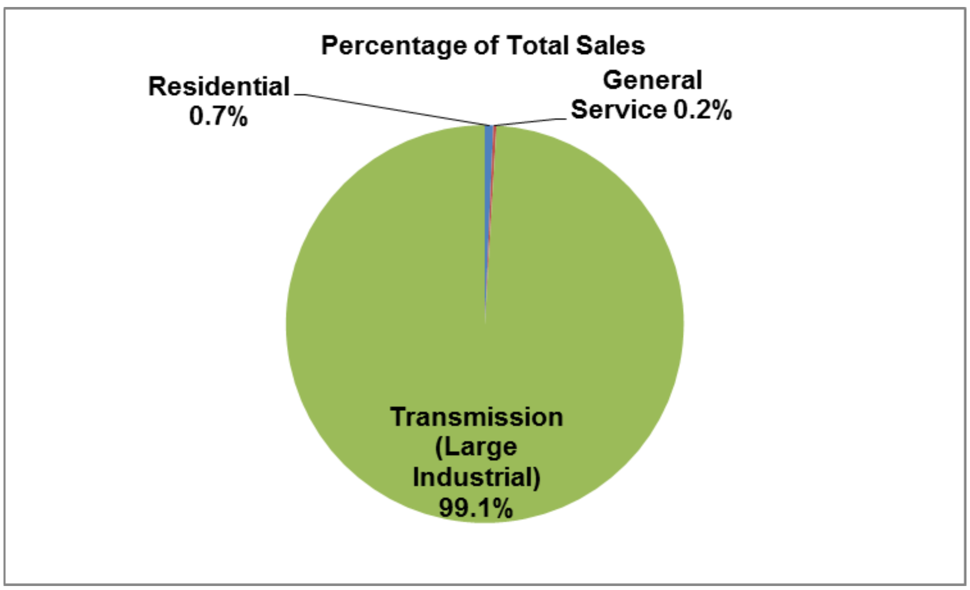
Topic: **Miscellaneous**

Reference: **Ince 1.4.1**

2.36.0 Please provide a pie chart showing breakdown of electricity sales (residential, general, transmission) by BC Hydro to customers via NTL/Iskut Extension for the most recent actual year available.

RESPONSE:

The pie chart below shows the fiscal 2019 billed sales on a percentage basis of all residential, light industrial and commercial (general service) customers in the community of Eddontenajon and the Red Chris mine, which are served by the Northwest Transmission Line (NTL).



Topic: **Miscellaneous**

Reference: **Ince 1.13.3**

2.37.0 Market liquidity: please confirm that it can be assumed that BC Hydro (for a price) could purchase firm energy from the Pacific Northwest (through Powerex) backed by firm transmission for a period of 1, 5 or 10 years.

RESPONSE:

This response also provides BC Hydro's response to INCE IRs 2.38.0 and 2.39.0.

Not Confirmed. For planning purposes, under the self-sufficiency provisions of the *Clean Energy Act*, BC Hydro cannot plan on purchasing firm energy to meet its load serving obligations. While BC Hydro may for operational reasons request that Powerex import energy to meet physical requirements or for economic optimization, BC Hydro does not plan on long-term firm purchases.

Topic: **Miscellaneous**

Reference: **Ince 1.13.3**

2.38.0 Please indicate the maximum rate of imports (MW) above which this could present difficulties, either due to market liquidity constraints, counterparty credit issues, or transmission access.

RESPONSE:

Please refer to BC Hydro's response to INCE IR 2.37.0.

Topic: **Miscellaneous**

Reference: **Ince 1.13.3**

2.39.0 Is it reasonable to assume that BC Hydro could import 100 MW of firm power from the Pacific Northwest for a 5-year period year-round (target: 8760 hours per year)? Is it reasonable to assume that BC Hydro could import the same quantity during the November to April timeframe (only) for 5 years?

RESPONSE:

Please refer to BC Hydro's response to INCE IR 2.37.0.

Reference: **Ince IR 1.8.41 Load Forecast Section 3.3.4.1, Application Section 7.5 and Table 7-9**

Regarding the Mining customer payment plan regulatory account, as stated in the Application section 7.5.6: "[The] 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;"

2.40.0 Please explain if this account still has a zero balance. Please indicate the current and reasonably foreseeable (market forwards pricing) coal and copper market prices.

RESPONSE:

The Mining Customer Payment Plan Regulatory Account continues to have a zero balance as of June 30, 2019.

The current futures prices in USD for coking coal from August 2019 to December 2022 are provided by the CME Group at the following link (please refer to the column titled "Prior Settle"): https://www.cmegroup.com/trading/energy/coal/australian-coking-coal-platts-low-vol-swap.html.

The current future prices in USD for copper from August 2019 to July 2024 are provided by the CME Group at the following link (please refer to the column titled "Prior Settle"): https://www.cmegroup.com/trading/metals/base/copper.html.

The August 2019 futures prices from the CME Group reflect the current market prices for the two commodities.

1.0 Reference: Chapter 3, section 3.2.8.1 Account by Account Approach

Willis Question Submitted on May 2, 2019 (1.4.1)

BC Hydro has a Strategic Energy Management (SEM) program in place for most if not all of their transmission customers; do the SEMs include electricity consumption forecasts for each customer facility?

BCH Response

BC Hydro works with transmission customers participating in the Strategic Energy Management program to develop a strategic energy management plan based on their operations that may include a forecast for electricity consumption. Inclusion of electricity consumption forecasting is not mandatory under the program; however, it is sometimes included in the plan because it can be useful to understand when a customer is anticipating a near-term change in consumption that could affect their DSM opportunities.

Information Request No.2 - 1

The load forecast of BC Hydro's large industrial customers is a critical aspect of the load forecast and it is understood that this forecast is put together on a site by site basis. It seems that it would be very useful to BC Hydro if a load forecast was a mandatory part of a SEM, signed off by a senior executive within the industrial customer's organization.

BC Hydro does contribute financially to the cost of an Energy Manager being on site monitoring electricity use and analyzing how electricity could be used more efficiently. This is an ideal person to coordinating the development of an annual load forecast for the site.

2.1.1 Why isn't such a load forecast a mandatory part of a SEM?

RESPONSE:

BC Hydro Key Account Managers regularly engage with large industrial customers to understand their current and future operations, including through the annual Customer Base Line review under the Transmission Service Rate. This information is used to inform the load forecast.

BC Hydro has not required this information as part of the Strategic Energy Management plan because it would be a duplication of effort.

2.0 Reference: Chapter 3, top of page 3 – 25

Willis Question Submitted on May 2, 2019 – (1.5.1)

Are customers that applying for new power, asked to complete a SEM for their potential facility? Is would this SEMD include a consumption forecast?

BCH Response

New and existing customers with a Key Account Manager assigned to them are made aware of BC Hydro's DSM programs, including the Strategic Energy Management program. If customers wish to participate in the program, a Strategic Energy Management plan is created. Please refer to BC Hydro's response to WILLIS IR 1.4.1 where we explain that a consumption forecast may form part of the Strategic Energy Management plan.

Information Request No. 2 - 2

An electric utility provides a key service to potential industrial customers by providing electric power at a new site. Planning for this additional power is a difficult challenge because of the uncertainty as to when and how much power will be required. It would be very useful to BC Hydro's load forecasting effort if customers applying for new power were required to submit a SEM including a load forecast. Such a SEM including a load forecast would allow BC Hydro and the customer to analyze efficiency and self generation options.

2.2.1 Why isn't a SEM with a load forecast required for new customers applying for new power?

RESPONSE:

If BC Hydro were to make it mandatory to participate in the SEM program in order to apply for new power it would not necessarily improve the load forecast and it could have other implications for BC Hydro's SEM program.

When a customer contacts BC Hydro about connecting to our system a series of interconnection and system impact studies are completed. Included in the studies are an estimate of the MWs of demand the customer wishes to contract and the expected annual consumption. This provides BC Hydro with information to inform its load forecasts.

Participation in BC Hydro's SEM program is currently voluntary. In order for the SEM program to be effective, customers have to be committed to making it work. If customers were required to enrol, the level of commitment to make it work

would not be present in each company and it would be uncertain as to how many would continue once connected and operating. In addition, by making it mandatory, instead of voluntary, customers who are not prepared or ready to commit to the effort required to make SEM successful may be dissatisfied with BC Hydro's approach and not be receptive to our energy management programs in the future.

3.0 Reference: Appendix X, page 7, Table 3

Wills Question Submitted on May 2, 2019 (1.13.1)

The Utility Test and the Modified Resource Test seem appropriate but does BC Hydro also use the Participant or Customer Test to evaluate individual programs?

BCH Response

BC Hydro uses the utility cost test and total resource cost test to understand the cost effectiveness of it DSM plan from both a utility and total resource perspective. The participant perspective is considered during the program design stage to better understand potential take up rate of the initiative by customers.

Information Request No.2 – 3

A very important service that is provided by BC Hydro's Conservation and Efficiency (C&E) efforts is reducing the cost of electricity to its customers. In actuality BC Hydro's owners are its customers so one of its important objectives is keeping electricity costs low and the C&E initiative plays an important role.

The utility cost and total resource test endeavour to monitor the impact that the C&E effort has on BCH's financial profitability. The data BCH has provided indicated that the C&E efforts do not have a negative financial impact on BC Hydro and in effect do not have a negative impact even on customers who do not participate in any C&E programs. Accordingly, these two tests are worthwhile and should be performed.

However, surely every C&E program should reduce the cost of electricity to customers who chose to participate.

2.3.1 Why isn't the results of a participant test published for every C&E program.

RESPONSE:

The cost-effectiveness tables provided are needed for regulatory requirements, our internal decision making process, and to assist the BCUC in their decision on our requested expenditures.

When designing DSM initiatives, we consider the participants' perspectives to better gauge the impact of the initiative in the market place and endeavour to make all our programs attractive to customers. Based on BC Hydro's experience, we believe customers will weigh the energy and non-energy benefits of participating in the program against the costs before making their decision to participate.

28.0 Topic: Residential Sector Load Forecast

Reference: Exhibit B-6, Zone II RPG IR 1.1.1

BC Hydro provided the following table (excerpt) in response to Zone II RPG IR 1.1.1:

Breakdown of Residential Sales by Region

	Integrated Areas			
	Lower Mainland (GWh)	Vancouver Island (GWh)	South Interior (GWh)	North Region (GWh)
F2013 (Actual)	9,359	1,493	2,236	4,531
F2014 (Actual)	9,518	1,492	2,350	4,524
F2015 (Actual)	9,058	1,509	2,235	4,161
F2016 (Actual)	9,242	1,447	2,276	4,286
F2017 (Actual)	9,602	1,492	2,376	4,516
F2018 (Actual)	9,637	1,500	2,424	4,507
F2019 (Forecast)	9,633	4,605	2,339	1,391
F2020 (Forecast)	9,745	4,658	2,366	1,407
F2021 (Forecast)	9,783	4,677	2,376	1,412

2.28.1 Please confirm the data as highlighted above is accurate for the Vancouver Island and North Region for the Integrated Areas.

RESPONSE:

This answer also responds to ZONE II RPG IR 2.28.1.1.

BC Hydro corrects our response to ZONE II RPG IR 1.1.1 in the table provided below.

Breakdown of Residential Sales by Region

	Integrated Areas			
	Lower Mainland (GWh)	Vancouver Island (GWh)	South Interior (GWh)	North Region (GWh)
F2013 (Actual)	9,359	1,493	2,236	4,531
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F2020 (Forecast)	9,745	1,407	2,366	4,658
F2021 (Forecast)	9,783	1,412	2,376	4,677

Notes

1. **Actual and forecasts are on an accrued sales basis. Integrated regional sales developed by allocating the difference between annual accrued sales and billed sales to the regions.**
2. **Source of the total residential actuals is BC Hydro's Annual Reports.**

28.0 Topic: Residential Sector Load Forecast

Reference: Exhibit B-6, Zone II RPG IR 1.1.1

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F2021 (Forecast)	9,783	4,677	2,376	1,412

2.28.1 Please confirm the data as highlighted above is accurate for the Vancouver Island and North Region for the Integrated Areas.

2.28.1.1 If this data is accurate, please explain the reasons for the changes for the Vancouver Island and North Regions from F2018 (Actual) to F2021 (Forecast).

RESPONSE:

Please refer to BC Hydro's response to ZONE II RPG IR 2.28.1, where a corrected table is provided.

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29.0 Topic: Cost of Energy - NIA

Reference: Exhibit B-6, Zone II RPG IR 1.4.1

In its response to Zone II RPG IR 1.4.1, BC Hydro stated:

The work to develop an approach to diesel reduction as described above is ongoing. The documentation of this work is not expected to be available until it is completed, anticipated for later in fiscal 2020. In the interim, BC Hydro will continue to work with Indigenous and non-Indigenous communities to understand their needs and interests and look at potential solutions.

2.29.1 Please provide an estimated timeline for “later in fiscal 2020”.

RESPONSE:

BC Hydro anticipates documentation related to BC Hydro’s updated approach to diesel reduction to be available in fall 2019 or winter 2020. BC Hydro is unable to provide a more precise timeline.

9.0 Topic: Cost of Energy - NIA

Reference: Exhibit B-6, Zone II RPG IR 1.4.1

In its response to Zone II RPG IR 1.4.1, BC Hydro stated:

The work to develop an approach to diesel reduction as described above is ongoing. The documentation of this work is not expected to be available until it is completed, anticipated for later in fiscal 2020. In the interim, BC Hydro will continue to work with Indigenous and non-Indigenous communities to understand their needs and interests and look at potential solutions.

2.29.2 Please provide more details on how BC Hydro will “work with Indigenous and non-Indigenous communities to understand their needs and interests and look at potential solutions” as it relates to diesel reduction in Zone II RPG.

RESPONSE:

This answer also responds to ZONE II RPG IR 2.29.2.1.

BC Hydro understands Zone II RPG communities to consist of the Kwadacha First Nation (Fort Ware, BC) and Tsay Keh Dene First Nation, as per Exhibit C-1 to this proceeding. BC Hydro endeavours to work with these communities to understand community expectations, load requirements and options to offset or displace diesel generation.

With respect to past projects, BC Hydro has an EPA with an operational biomass facility located in Fort Ware, which was accepted by the BCUC in 2016 pursuant to BCUC Order No. E-5-16.

As of 2016, BC Hydro and Tsay Keh Dene community leaders have initiated semi-annual meetings (or as required) to discuss community growth and planning. Potential projects and initiatives are evaluated to ensure they are technically viable, cost-effective and meet load requirements.

BC Hydro is unable to provide any information on potential proposals from Zone II RPG communities as any such discussions would be subject to non-disclosure agreements to protect the commercial interests of both BC Hydro and a proponent.

Please also refer to BC Hydro’s response to INCE IR 2.30.0 for additional information on BC Hydro’s approach to achieving CleanBC objectives.

29.0 Topic: Cost of Energy - NIA

Reference: Exhibit B-6, Zone II RPG IR 1.4.1

In its response to Zone II RPG IR 1.4.1, BC Hydro stated:

The work to develop an approach to diesel reduction as described above is ongoing. The documentation of this work is not expected to be available until it is completed, anticipated for later in fiscal 2020. In the interim, BC Hydro will continue to work with Indigenous and non-Indigenous communities to understand their needs and interests and look at potential solutions.

2.29.2 Please provide more details on how BC Hydro will "work with Indigenous and non-Indigenous communities to understand their needs and interests and look at potential solutions" as it relates to diesel reduction in Zone II RPG.

2.29.2.1 Identify any specific proposals with respect to the Zone II RPG communities.

RESPONSE:

Please refer to BC Hydro's response to ZONE II RPG IR 2.29.2.

29.0 Topic: Cost of Energy - NIA

Reference: Exhibit B-6, Zone II RPG IR 1.4.1

In its response to Zone II RPG IR 1.4.1, BC Hydro stated:

The work to develop an approach to diesel reduction as described above is ongoing. The documentation of this work is not expected to be available until it is completed, anticipated for later in fiscal 2020. In the interim, BC Hydro will continue to work with Indigenous and non-Indigenous communities to understand their needs and interests and look at potential solutions.

2.29.2 Please provide more details on how BC Hydro will “work with Indigenous and non-Indigenous communities to understand their needs and interests and look at potential solutions” as it relates to diesel reduction in Zone II RPG.

2.29.2.2 Is BC Hydro planning on conducting a formal engagement process?

RESPONSE:

BC Hydro has not made any decisions on the engagement approach for any potential analysis or projects related to diesel reduction in NIA communities.

29.0 Topic: Cost of Energy - NIA

Reference: Exhibit B-6, Zone II RPG IR 1.4.1

In its response to Zone II RPG IR 1.4.1, BC Hydro stated:

The work to develop an approach to diesel reduction as described above is ongoing. The documentation of this work is not expected to be available until it is completed, anticipated for later in fiscal 2020. In the interim, BC Hydro will continue to work with Indigenous and non-Indigenous communities to understand their needs and interests and look at potential solutions.

2.29.2 Please provide more details on how BC Hydro will "work with Indigenous and non-Indigenous communities to understand their needs and interests and look at potential solutions" as it relates to diesel reduction in Zone II RPG.

2.29.2.3 Is BC Hydro planning on issuing a call or RFP as part of this approach?

RESPONSE:

BC Hydro has not made any decisions on a procurement approach for any potential projects pursued for diesel reduction in NIA communities.

29.0 Topic: Cost of Energy - NIA

Reference: Exhibit B-6, Zone II RPG IR 1.4.1

In its response to Zone II RPG IR 1.4.1, BC Hydro stated:

The work to develop an approach to diesel reduction as described above is ongoing. The documentation of this work is not expected to be available until it is completed, anticipated for later in fiscal 2020. In the interim, BC Hydro will continue to work with Indigenous and non-Indigenous communities to understand their needs and interests and look at potential solutions.

2.29.2 Please provide more details on how BC Hydro will "work with Indigenous and non-Indigenous communities to understand their needs and interests and look at potential solutions" as it relates to diesel reduction in Zone II RPG.

2.29.2.4 Does BC Hydro consider efforts to reduce diesel use part of its broader reconciliation efforts with Indigenous communities in Zone II RPG, and if so how?

RESPONSE:

BC Hydro's statement of Indigenous Principles commits BC Hydro to seeking solutions to improving the accessibility of clean, reliable and affordable power to Indigenous communities in remote areas of the province. Reduction of diesel consumption is an area of interest shared by BC Hydro and Indigenous communities, particularly in remote communities such as those represented by Zone II Ratepayers Group.

Engagement with Indigenous communities on diesel reduction through exploring clean energy alternatives and implementing Demand Side Management solutions, including capacity development, provides an opportunity for BC Hydro to gain a deeper understanding of Indigenous interests and values in the area of energy use, and supports reconciliation.

30.0 Topic: Cost of Energy – NIA Forecast Increases

Reference: Exhibit B-6, Zone II RPG IR 1.5.1

In BC Hydro's response to Zone II RPG IR 1.5.1, BC Hydro states:

No assessment has been conducted of how much electricity generation from diesel resources could be displaced by existing and planned IPPs in the Non-Integrated Areas.

2.30.1 Why has no assessment been conducted?

RESPONSE:

This answer also responds to ZONE II RPG IR 2.30.1.1.

BC Hydro believes an assessment of possible levels of diesel reduction by existing and planned IPPs in Non-Integrated Areas would not be an efficient use of resources.

While 100 per cent diesel reduction may be technically feasible in a remote community, the cost of achieving this with the current state of technologies may be prohibitive. An assessment of possible levels of diesel reduction with existing and expected funding would require a resource-intensive analysis of each community load profile/forecast, available renewable resources, available generation technologies, and community aspirations.

As many of these communities have low levels of renewable generation at this time, the assessment of a theoretical maximum for achievable diesel reduction in communities is not a critical input to the development of diesel reduction plans. When communities reach higher levels of renewable penetration such an analysis may be required and would be able to reflect the then-current state of available technology. BC Hydro does not believe such analysis would be required by the end of fiscal 2020.

30.0 Topic: Cost of Energy – NIA Forecast Increases

Reference: Exhibit B-6, Zone II RPG IR 1.5.1

In BC Hydro's response to Zone II RPG IR 1.5.1, BC Hydro states:

No assessment has been conducted of how much electricity generation from diesel resources could be displaced by existing and planned IPPs in the Non-Integrated Areas.

2.30.1 Why has no assessment been conducted?

2.30.1.1 Will this assessment be done as part of the CleanBC plan for later in fiscal 2020?

RESPONSE:

Please refer to BC Hydro's response to ZONE II RPG IR 2.30.1.

30.0 Topic: Cost of Energy – NIA Forecast Increases

Reference: Exhibit B-6, Zone II RPG IR 1.5.1

In BC Hydro's response to Zone II RPG IR 1.5.1, BC Hydro states:

No assessment has been conducted of how much electricity generation from diesel resources could be displaced by existing and planned IPPs in the Non-Integrated Areas.

2.30.2 Confirm, or explain otherwise, if BC Hydro will establish targets on how much electricity generation from diesel resources will be displaced as part of the CleanBC plan.

RESPONSE:

BC Hydro has not made any decisions on whether targets will be established for any potential diesel reduction in NIA communities.

31.0 Topic: Cost of Energy – NIA Forecast Increases

Reference: Exhibit B-6, Zone II RPG IR 1.5.2, 1.5.2.1

In BC Hydro's response to Zone II RPG IR 1.5.2, BC Hydro states:

In areas where diesel is the stand-by electricity source, the diesel stations are required only to maintain reliable electrical service in the event there is a planned outage or forced outage of the clean or renewable energy source.

In BC Hydro's response to Zone II RPG 1.5.2.1, BC Hydro provides *a list of potential commercial technologies that could be deployed to displace the use of diesel generation in the Non-Integrated Areas (NIA).*

Options to reduce electricity consumption through deployment of demand-side management initiatives:

- **Weatherization upgrades (e.g., draftproofing, insulation, windows, doors, ventilation systems)**
- **Energy efficient appliances (e.g., fridges, freezers, heat pump dryers)**
- **Air source heat pumps**
- **Biomass boilers**
- **High efficiency faucets and aerators, low flow toilets**
- **Heat pump water heaters**
- **Solar water heaters**
- **Load management (e.g., water and space heating load shifting)**
- **Customer-sited energy storage (e.g., batteries)**

Options to increase clean or renewable energy generation by deployment of:

- **Hydro generators (run of river or storage hydro)**
- **Solar generators**
- **Wind generators**
- **Biomass generators:**
  - **Combustion – Organic Rankine Cycle (ORC) turbine generators**
  - **Gasification – Internal Combustion Engine (ICE) generators**

- ▶ **Combined heat and power biomass plants**
- **Battery storage and micro-grid controls**

2.31.1 Other than diesel, are there any other ways to maintain reliable electrical service that are less costly than the diesel stations?

RESPONSE:

The renewable energy supply options mentioned in the preamble to the question are typically more costly than diesel generation in off-grid communities. However, they can become competitive as a result of various factors, including the following:

- **Injections of funding from the Government of Canada and Government of B.C.;**
- **Reductions in the cost of renewable technologies over time; and**
- **Increases in the cost of diesel fuel due to one or more of increased underlying commodity costs and carbon taxes.**

31.0 Topic: Cost of Energy – NIA Forecast Increases

Reference: Exhibit B-6, Zone II RPG IR 1.5.2, 1.5.2.1

In BC Hydro's response to Zone II RPG IR 1.5.2, BC Hydro states:

In areas where diesel is the stand-by electricity source, the diesel stations are required only to maintain reliable electrical service in the event there is a planned outage or forced outage of the clean or renewable energy source.

In BC Hydro's response to Zone II RPG 1.5.2.1, BC Hydro provides *a list of potential commercial technologies that could be deployed to displace the use of diesel generation in the Non-Integrated Areas (NIA).*

Options to reduce electricity consumption through deployment of demand-side management initiatives:

- **Weatherization upgrades (e.g., draftproofing, insulation, windows, doors, ventilation systems)**
- **Energy efficient appliances (e.g., fridges, freezers, heat pump dryers)**
- **Air source heat pumps**
- **Biomass boilers**
- **High efficiency faucets and aerators, low flow toilets**
- **Heat pump water heaters**
- **Solar water heaters**
- **Load management (e.g., water and space heating load shifting)**
- **Customer-sited energy storage (e.g., batteries)**

Options to increase clean or renewable energy generation by deployment of:

- **Hydro generators (run of river or storage hydro)**
- **Solar generators**
- **Wind generators**
- **Biomass generators:**
  - ► **Combustion – Organic Rankine Cycle (ORC) turbine generators**
  - ► **Gasification – Internal Combustion Engine (ICE) generators**

- ▶ **Combined heat and power biomass plants**
- **Battery storage and micro-grid controls**

2.31.2 Confirm that the new NIA DSM program include all these options above to reduce electricity consumption through DSM initiatives.

RESPONSE:

The new Non-Integrated Area Demand Side Management program currently includes the following measures from the list provided in BC Hydro's response to ZONE II RPG IR 1.5.2.1:

- **Weatherization upgrades (e.g., draft proofing, insulation, windows, doors, ventilation);**
- **Energy efficient appliances (e.g., refrigerators and freezers);**
- **Air source heat pumps;**
- **High efficiency faucets and aerators; and**
- **Heat pump water heaters.**

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31.0 Topic: Cost of Energy – NIA Forecast Increases

Reference: Exhibit B-6, Zone II RPG IR 1.5.2, 1.5.2.1

In BC Hydro's response to Zone II RPG IR 1.5.2, BC Hydro states:

In areas where diesel is the stand-by electricity source, the diesel stations are required only to maintain reliable electrical service in the event there is a planned outage or forced outage of the clean or renewable energy source.

In BC Hydro's response to Zone II RPG 1.5.2.1, BC Hydro provides *a list of potential commercial technologies that could be deployed to displace the use of diesel generation in the Non-Integrated Areas (NIA).*

Options to reduce electricity consumption through deployment of demand-side management initiatives:

- **Weatherization upgrades (e.g., draftproofing, insulation, windows, doors, ventilation systems)**
- **Energy efficient appliances (e.g., fridges, freezers, heat pump dryers)**
- **Air source heat pumps**
- **Biomass boilers**
- **High efficiency faucets and aerators, low flow toilets**
- **Heat pump water heaters**
- **Solar water heaters**
- **Load management (e.g., water and space heating load shifting)**
- **Customer-sited energy storage (e.g., batteries)**

Options to increase clean or renewable energy generation by deployment of:

- **Hydro generators (run of river or storage hydro)**
- **Solar generators**
- **Wind generators**
- **Biomass generators:**
  - **Combustion – Organic Rankine Cycle (ORC) turbine generators**
  - **Gasification – Internal Combustion Engine (ICE) generators**
  - **Combined heat and power biomass plants**
- **Battery storage and micro-grid controls**

2.31.2 Confirm that the new NIA DSM program include all these options above to reduce electricity consumption through DSM initiatives.

2.31.2.1 If not, why not and explain plans for investigating these DSM initiatives.

RESPONSE:

BC Hydro did not include five of the options listed in BC Hydro's response to ZONE II RPG IR 1.5.2.1 under options to reduce electricity consumption.

Two of the options (load management and customer sited energy storage) are potential options for shifting loads and achieving capacity reductions but are not options for reducing electricity consumption.

The reasons for not including the remaining three options and any further plans for investigating them are listed below:

- **Solar water heaters - not included due to cost effectiveness and concerns related to maintenance challenges. At this time BC Hydro does not plan to further investigate this technology for application in the Non-Integrated Areas;**
- **Biomass boilers – not considered applicable for the residential market, but may be considered for commercial applications if suitable opportunities arise; and**
- **Low flow toilets – not included with the other water saving measures because they do not have the same electricity saving potential given the water is not heated. They do have some potential to reduce electricity related to water pumping infrastructure. BC Hydro plans to investigate the potential of the water pumping technologies as an energy saving measure.**

31.0 Topic: Cost of Energy – NIA Forecast Increases

Reference: Exhibit B-6, Zone II RPG IR 1.5.2, 1.5.2.1

In BC Hydro's response to Zone II RPG IR 1.5.2, BC Hydro states:

In areas where diesel is the stand-by electricity source, the diesel stations are required only to maintain reliable electrical service in the event there is a planned outage or forced outage of the clean or renewable energy source.

In BC Hydro's response to Zone II RPG 1.5.2.1, BC Hydro provides *a list of potential commercial technologies that could be deployed to displace the use of diesel generation in the Non-Integrated Areas (NIA).*

Options to reduce electricity consumption through deployment of demand-side management initiatives:

- **Weatherization upgrades (e.g., draftproofing, insulation, windows, doors, ventilation systems)**
- **Energy efficient appliances (e.g., fridges, freezers, heat pump dryers)**
- **Air source heat pumps**
- **Biomass boilers**
- **High efficiency faucets and aerators, low flow toilets**
- **Heat pump water heaters**
- **Solar water heaters**
- **Load management (e.g., water and space heating load shifting)**
- **Customer-sited energy storage (e.g., batteries)**

Options to increase clean or renewable energy generation by deployment of:

- **Hydro generators (run of river or storage hydro)**
- **Solar generators**
- **Wind generators**
- **Biomass generators:**
  - ▶ **Combustion – Organic Rankine Cycle (ORC) turbine generators**
  - ▶ **Gasification – Internal Combustion Engine (ICE) generators**

- ► **Combined heat and power biomass plants**
- **Battery storage and micro-grid controls**

2.31.3 Confirm CleanBC plan will include investigating the above options for increasing clean or renewable energy generation in the NIA.

RESPONSE:

This answer also responds to ZONE II RPG IR 2.31.3.1.

BC Hydro understands the "CleanBC plan" in the question refers to BC Hydro's actions in support of the Government of B.C.'s CleanBC report (i.e., the work described in BC Hydro's response to ZONE II RPG IR 1.4.1).

BC Hydro's diesel reduction approach in NIA communities is expected to consider some or all of the demand-side and supply-side options described in BC Hydro's response to ZONE II RPG IR 1.5.2.1. The extent to which these options are assessed in a specific NIA community is likely to vary as the potential for such projects to be successful tends to be dependent on both the community location and the NIA grid characteristics.

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31.0 Topic: Cost of Energy – NIA Forecast Increases

Reference: Exhibit B-6, Zone II RPG IR 1.5.2, 1.5.2.1

In BC Hydro’s response to Zone II RPG IR 1.5.2, BC Hydro states:

In areas where diesel is the stand-by electricity source, the diesel stations are required only to maintain reliable electrical service in the event there is a planned outage or forced outage of the clean or renewable energy source.

In BC Hydro’s response to Zone II RPG 1.5.2.1, BC Hydro provides *a list of potential commercial technologies that could be deployed to displace the use of diesel generation in the Non-Integrated Areas (NIA).*

Options to reduce electricity consumption through deployment of demand-side management initiatives:

- **Weatherization upgrades (e.g., draftproofing, insulation, windows, doors, ventilation systems)**
- **Energy efficient appliances (e.g., fridges, freezers, heat pump dryers)**
- **Air source heat pumps**
- **Biomass boilers**
- **High efficiency faucets and aerators, low flow toilets**
- **Heat pump water heaters**
- **Solar water heaters**
- **Load management (e.g., water and space heating load shifting)**
- **Customer-sited energy storage (e.g., batteries)**

Options to increase clean or renewable energy generation by deployment of:

- **Hydro generators (run of river or storage hydro)**
- **Solar generators**
- **Wind generators**
- **Biomass generators:**
  - ▶ **Combustion – Organic Rankine Cycle (ORC) turbine generators**
  - ▶ **Gasification – Internal Combustion Engine (ICE) generators**

- ► **Combined heat and power biomass plants**
- **Battery storage and micro-grid controls**

2.31.3 Confirm CleanBC plan will include investigating the above options for increasing clean or renewable energy generation in the NIA.

2.31.3.1 If not, explain the reasons why.

RESPONSE:

Please refer to BC Hydro’s response to ZONE II RPG IR 2.31.3.

32.0 Topic: Cost of Energy – NIA Forecast Increases
Reference: Exhibit B-1 Application, Exhibit B-6, Zone II RPG IR 1.5.4

On page 4-34 of Exhibit B-1 of its F2020-F2021 Application, BC Hydro provides the following:

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

In BC Hydro's response to Zone II RPG IR 1.5.4, BC Hydro provides the following:

The diesel price forecast used by BC Hydro for the test period is as follows (from the [redacted]:

- **F2020 Plan – [redacted]; and**
- **F2021 Plan – [redacted].**

2.32.1 Provide the actual diesel prices corresponding to Table 4-14 for F2017, F2018 and F2019. If actuals are not available for F2019, please provide the forecast prices.

RESPONSE:

The public version of this response has been redacted to maintain in confidence commercially sensitive information. The unredacted version of this response is being filed in confidence with the BCUC only as public disclosure could impact BC Hydro's commercial interests related to BC Hydro's supply agreements with diesel suppliers and negotiations of Electricity Purchase Agreements.

The public version of this response has been redacted to maintain in confidence commercially sensitive information. The un-redacted version of this response is being filed in confidence with the BCUC only as public disclosure could impact BC Hydro's commercial interests related to BC Hydro's supply agreements with diesel suppliers and negotiations of Electricity Purchase Agreements.

The table below provides the actual diesel unit costs for fiscal 2017 to fiscal 2019, as well as BC Hydro's forecast diesel unit costs for the Test Period in the Application and in the Evidentiary Update.

($/MMBtu)	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Plan	F2020 EU	F2021 Plan	F2021 EU
Unit Cost of Diesel, inclusive of transport and taxes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

BC Hydro notes the following:

- **The costs above are inclusive of diesel transportation costs and taxes (including the carbon tax); however, the forecast diesel prices (for F2020 Plan and F2021 Plan) provided in BC Hydro's response to ZONE II RPG IR 1.5.4 did not include these adjustments. To allow for comparability to BC Hydro's historical diesel unit costs, BC Hydro has also estimated the Test Period diesel unit costs inclusive of transportation costs and taxes; and**
- **The above costs represent the average unit cost for all of BC Hydro's NIA communities. However, the unit cost of diesel for a specific NIA community will vary from this average amount.**

32.0 Topic: Cost of Energy – NIA Forecast Increases
Reference: Exhibit B-1 Application, Exhibit B-6, Zone II RPG IR 1.5.4

On page 4-34 of Exhibit B-1 of its F2020-F2021 Application, BC Hydro provides the following:

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

In BC Hydro's response to Zone II RPG IR 1.5.4, BC Hydro provides the following:

The diesel price forecast used by BC Hydro for the test period is as follows (from the [redacted]:

- **F2020 Plan – [redacted]; and**
- **F2021 Plan – [redacted].**

2.32.2 Provide the actual, or forecast if actuals not available, total diesel expenditures in ($ million) for F2017, F2018, F2019.

RESPONSE:

This response includes confidential information that pertains to our August 2019 Cost of Energy Evidentiary Update, in accordance with Order No. G-146-19, which has been redacted in the public version of this response. The un-redacted version of the response is being made available to the BCUC only.

BC Hydro interprets the question to refer to total diesel expenditures for the NIA Cost of Energy forecast. Table 4-14 of the Application provides the NIA diesel expenditures inclusive of transportation cost and tax. The table below provides the Cost of Energy for diesel in the NIA for fiscal 2017 to fiscal 2019, as well as BC Hydro's forecast Cost of Energy for diesel in the NIA for the Test Period in the Application and in the Evidentiary Update.

$millions	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Plan	F2020 EU	F2021 Plan	F2021 EU
NIA – BC Hydro Diesel Generating Stations	**15.0**	**16.3**	**19.7**	**21.3**	[redacted]	**23.5**	[redacted]

While 100% diesel reduction is likely technically feasible in any community, the cost of reaching this level of diesel reduction may be prohibitive. An assessment of what level of 32.0 Topic: Cost of Energy – NIA Forecast Increases

Reference: Exhibit B-1 Application, Exhibit B-6, Zone II RPG IR 1.5.4

On page 4-34 of Exhibit B-1 of its F2020-F2021 Application, BC Hydro provides the following:

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

In BC Hydro's response to Zone II RPG IR 1.5.4, BC Hydro provides the following:

The diesel price forecast used by BC Hydro for the test period is as follows (from the [redacted]:

- **F2020 Plan – [redacted]; and**
- **F2021 Plan – [redacted].**

2.32.3 Provide the planned total diesel expenditures for the test period.

RESPONSE:

Please refer to BC Hydro's response to ZONE II RPG IR 2.32.2.

33.0 Topic: Cost of Energy – NIA Forecast Increases

Reference: Exhibit B-6, Zone II RPG IR 1.5.4.1

In its response to Zone II RPG IR 1.5.4.1, BC Hydro states:

BC Hydro uses a number of strategies to manage diesel price risk for diesel procurement in the Non-Integrated Areas.

…..

- *Securing rack rate (wholesale) prices instead of retail rates*

2.33.1 Does BC Hydro have a price risk management policy for diesel? If so, please provide. If not, please provide the reasons why not.

RESPONSE:

This answer also responds to ZONE II RPG IR 2.33.2.

No, BC Hydro does not have a price risk management policy for diesel.

The diesel volume purchased by BC Hydro is relatively small (approximately 20 to 25 million litres/year) and as such, BC Hydro does not have significant market purchasing power in comparison to other market customers purchasing bulk diesel.

To mitigate price risk, BC Hydro uses multiple non-committed and non-exclusive supplier contracts based on spot pricing. Diesel is a commodity product with prices linked to global supply and demand, and using multiple contracts allows BC Hydro to create price competition between suppliers, and provides the flexibility to move between suppliers without penalty. In general, the price variance between BC Hydro's best-priced suppliers is very low at approximately 1 to 2 cents per litre.

In addition, BC Hydro's diesel purchase contracts include both fuel supply and fuel delivery to the facilities. Reliable delivery is a critical component of these supplier contracts so that BC Hydro can mitigate customer power interruption risks given the remote locations of the Non-Integrated Areas.

33.0 Topic: Cost of Energy – NIA Forecast Increases

Reference: Exhibit B-6, Zone II RPG IR 1.5.4.1

In its response to Zone II RPG IR 1.5.4.1, BC Hydro states:

BC Hydro uses a number of strategies to manage diesel price risk for diesel procurement in the Non-Integrated Areas.

…..

- *Securing rack rate (wholesale) prices instead of retail rates*

2.33.1.1 Does Powerex manage diesel procurement for BC Hydro? If not, please provide the reasons why not and identify the department within BC Hydro that manages diesel procurement.

RESPONSE:

No, Powerex does not manage diesel procurement for BC Hydro given the relatively small volume of diesel purchased and given that the procurement is not just for the commodity but also for the full service of the supply and delivery of the product to remote locations via truck and barge.

Diesel procurement is managed by the Procurement Department within the Supply Chain KBU of the Finance, Technology, Supply Chain Business Group.

33.0 Topic: Cost of Energy – NIA Forecast Increases

Reference: Exhibit B-6, Zone II RPG IR 1.5.4.1

In its response to Zone II RPG IR 1.5.4.1, BC Hydro states:

BC Hydro uses a number of strategies to manage diesel price risk for diesel procurement in the Non-Integrated Areas.

…..

- *Securing rack rate (wholesale) prices instead of retail rates*

2.33.2 Does BC Hydro procure diesel based on fixed or spot pricing or a combination?

RESPONSE:

BC Hydro procures diesel based on spot pricing, which is benchmarked to rack rates that vary daily based on the global market. For further discussion on BC Hydro's approach to diesel procurement, please refer to BC Hydro's response to ZONE II RPG IR 2.33.1.

34.0 Topic: Cost of Energy – NIA Forecast Increases

Reference: Exhibit B-1 Application, Section 4.7.2 Table 4-14, page 4-34; Exhibit B-6, Zone II RPG IR 1.5.4.2

On page 4-34 of Exhibit B-1 of its F2020-F2021 Application, BC Hydro provides the following:

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

In BC Hydro's response to Zone II RPG 1.5.4.2, BC Hydro states:

The Non-Integrated Areas ten-year capital plan includes funding to implement projects that will reduce overall electrical consumption within the Non-Integrated Areas generating facilities. Upgrades include LED station lighting and non-electric station building and equipment heating, which help to increase overall station efficiencies and reduce costs.

BC Hydro is also modernizing its existing diesel generator fleet as part of long-term capital plans by retiring older end of life units and replacing them with modern, more fuel efficient units. Unit fuel efficiency is a key consideration when comparing equipment lifecycle costs during the new generating equipment selection process.

2.34.1 What are the costs in the Test Period, if any, for these projects to reduce overall electricity consumption within the NIA? If there are no anticipated costs, what is the timeline for these projects to be initiated?

RESPONSE:

BC Hydro has budgeted $0.2 million during the Test Period for upgrades directly aimed at reducing station service electrical loads within the NIA supplied by BC Hydro diesel generating stations.

Zone II Ratepayers Group Information Request No. **2.34.2** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 2
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34.0 Topic: Cost of Energy – NIA Forecast Increases

Reference: Exhibit B-1 Application, Section 4.7.2 Table 4-14, page 4-34; Exhibit B-6, Zone II RPG IR 1.5.4.2

On page 4-34 of Exhibit B-1 of its F2020-F2021 Application, BC Hydro provides the following:

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
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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

In BC Hydro's response to Zone II RPG 1.5.4.2, BC Hydro states:

The Non-Integrated Areas ten-year capital plan includes funding to implement projects that will reduce overall electrical consumption within the Non-Integrated Areas generating facilities. Upgrades include LED station lighting and non-electric station building and equipment heating, which help to increase overall station efficiencies and reduce costs.

BC Hydro is also modernizing its existing diesel generator fleet as part of long-term capital plans by retiring older end of life units and replacing them with modern, more fuel efficient units. Unit fuel efficiency is a key consideration when comparing equipment lifecycle costs during the new generating equipment selection process.

2.34.2 Given the high avoided cost of generation in the NIA, are these projects being prioritized to be implemented in the communities? If not, why not?

RESPONSE:

The ability to offset the high cost of generation in the NIA provides incremental benefits to projects in the NIA compared to similar projects located in other areas of the province. These incremental benefits include financial savings and environmental risk reduction and would be reflected in the project prioritizations which are performed in accordance with BC Hydro's capital planning process.

For further information on BC Hydro's capital planning process, please refer to section 6.3 of Chapter 6 of the Application.

34.0 Topic: Cost of Energy – NIA Forecast Increases

Reference: Exhibit B-1 Application, Section 4.7.2 Table 4-14, page 4-34; Exhibit B-6, Zone II RPG IR 1.5.4.2

On page 4-34 of Exhibit B-1 of its F2020-F2021 Application, BC Hydro provides the following:

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
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The Non-Integrated Areas ten-year capital plan includes funding to implement projects that will reduce overall electrical consumption within the Non-Integrated Areas generating facilities. Upgrades include LED station lighting and non-electric station building and equipment heating, which help to increase overall station efficiencies and reduce costs.

BC Hydro is also modernizing its existing diesel generator fleet as part of long-term capital plans by retiring older end of life units and replacing them with modern, more fuel efficient units. Unit fuel efficiency is a key consideration when comparing equipment lifecycle costs during the new generating equipment selection process.

2.34.3 What criteria/strategy has BC Hydro used in the past to make decisions as part of its capital planning process in the NIA?

RESPONSE:

Historical capital planning decisions in the Non-Integrated Areas (NIA) have been made using our capital investment planning criteria. Factors which may have increased relevance for projects within the NIA include financial savings and

environmental risk reduction. Details of our capital planning process can be found in section 6.3 of Chapter 6 of the Application.

Examples of recently completed projects resulting in a reduction in diesel consumption and therefore financial savings and reduced environmental risk include:

- **Replacement of a 41-year old 2.5 MW stationary diesel genset with two new smaller 1.3 MW mobile diesel gensets. These gensets are more fuel efficient, have less emissions and provide more flexibility required for integration of renewables across the fleet; and**
- **Upgrade of a powerhouse to improve ventilation and roof insulation resulting in energy savings.**

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35.0 Topic: Operating Costs – Total Rewards Program

Reference: Exhibit B-1 Application, Section 5.2, Table 5-1, page 5-7, Section 5.6.5.2 Application; Exhibit B-5, BCUC IR 1.42.1, Exhibit B-6, Zone II RPG IR 1.8.1

BC Hydro states that:

A 2017 assessment by Morneau Shepell concluded that, on average total cash basis, BC Hydro employees earn 11 per cent less than median market rates.

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

In BC Hydro's response to BCUC IR 1.42.1, it states that:

Planned salary increases for union employees over the test period are 2 per cent per year which is consistent with the bargaining mandate set by the Public Sector Employers Council.

……

Planned salary increases for management and professional employees over the test period are 2.5 per cent per year which is similar to forecast inflation and market salary increases. While there is discretion in determining management and professional salary increase budgets, it would be difficult to continue to attract and retain employees if salaries do not increase over time and remain competitive with the market.

…….

As discussed in Section 5.6.5.2 of Chapter 5 of the Application, a 2017 assessment by Morneau Shepell concluded that BC Hydro's compensation package is 2 per cent below median market rates.

2.35.1 Confirm that the Morneau Shepell assessment includes all employees within BC Hydro?

RESPONSE:

This answer also responds to ZONE II RPG IR 2.35.1.1.

Not confirmed.

The market compensation surveys that were used to collect market salary and incentive pay information, as described in BC Hydro's response to BCUC IR 1.52.1, collect and report information for a limited number of jobs. Market data is generally only available for jobs that are common in other organizations, such as Engineers. Jobs available in the survey that were a good match to BC Hydro jobs were used in the market assessment. The jobs used represent approximately half of all BC Hydro employees.

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British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit:** **B-13**

35.0 Topic: Operating Costs – Total Rewards Program

Reference: Exhibit B-1 Application, Section 5.2, Table 5-1, page 5-7, Section 5.6.5.2 Application; Exhibit B-5, BCUC IR 1.42.1, Exhibit B-6, Zone II RPG IR 1.8.1

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…….

As discussed in Section 5.6.5.2 of Chapter 5 of the Application, a 2017 assessment by Morneau Shepell concluded that BC Hydro's

compensation package is 2 per cent below median market rates.

2.35.1 Confirm that the Morneau Shepell assessment includes all employees within BC Hydro?

2.35.1.1 If not, please explain list the employee groups that were excluded and the reasons why they were not included.

RESPONSE:

Please refer to BC Hydro's response to ZONE II RPG IR 2.35.1 which explains that a selection of benchmark jobs available within the market compensation surveys was used for the assessment.

Zone II Ratepayers Group Information Request No. **2.35.1.1.1** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 2
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

35.0 Topic: Operating Costs – Total Rewards Program

Reference: Exhibit B-1 Application, Section 5.2, Table 5-1, page 5-7, Section 5.6.5.2 Application; Exhibit B-5, BCUC IR 1.42.1, Exhibit B-6, Zone II RPG IR 1.8.1

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…….

As discussed in Section 5.6.5.2 of Chapter 5 of the Application, a 2017 assessment by Morneau Shepell concluded that BC Hydro's compensation package is 2 per cent below median market rates.

2.35.1.1.1 Confirm that Table 5-15 includes labour costs for all BC Hydro employees. If not, please identify any group of employees not included and update Table 5-15 including these excluded groups of employees.

RESPONSE:

Confirmed.

35.0 Topic: Operating Costs – Total Rewards Program

Reference: Exhibit B-1 Application, Section 5.2, Table 5-1, page 5-7, Section 5.6.5.2 Application; Exhibit B-5, BCUC IR 1.42.1, Exhibit B-6, Zone II RPG IR 1.8.1

BC Hydro states that:

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In BC Hydro's response to BCUC IR 1.42.1, it states that:

Planned salary increases for union employees over the test period are 2 per cent per year which is consistent with the bargaining mandate set by the Public Sector Employers Council.

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Planned salary increases for management and professional employees over the test period are 2.5 per cent per year which is similar to forecast inflation and market salary increases. While there is discretion in determining management and professional salary increase budgets, it would be difficult to continue to attract and retain employees if salaries do not increase over time and remain competitive with the market.

…….

As discussed in Section 5.6.5.2 of Chapter 5 of the Application, a 2017 assessment by Morneau Shepell concluded that BC Hydro's compensation package is 2 per cent below median market rates.

2.35.2 Provide the justification for the 2.5% planned salary increase for management and professional employees as compared to the 2%

planned salary increase for union employees and the assessment by Morneau Shepell that BC Hydro's compensation package is 2% below median market rates.

RESPONSE:

As described in BC Hydro's response to BCUC IR 1.42.5, management and professional salaries did not keep pace with Union wage increases since 2012.

The 2.5 per cent salary increases planned for management and professional employees is intended to keep pace with market forecasted salary increases going forward. For example, the Conference Board of Canada forecasts the average pay increase for non-unionized Canadian employees is projected to be 2.6 per cent in 2019 (refer to: https://conferenceboard.ca/press/newsrelease/2018/10/31/slightly-higher-salary-increases-expected-for-canadian-workers-in-2019).

Keeping pace with market salaries will avoid our compensation from becoming less competitive over time, and will allow us to continue to attract and retain employees.

Union wage increases are limited to 2 per cent in accordance with the Public Sector Employers' Council collective bargaining mandate.

35.0 Topic: Operating Costs – Total Rewards Program

Reference: Exhibit B-1 Application, Section 5.2, Table 5-1, page 5-7, Section 5.6.5.2 Application; Exhibit B-5, BCUC IR 1.42.1, Exhibit B-6, Zone II RPG IR 1.8.1

BC Hydro states that:

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Management and Professionals	1,621	97.66	100.69	102.48

In BC Hydro's response to BCUC IR 1.42.1, it states that:

Planned salary increases for union employees over the test period are 2 per cent per year which is consistent with the bargaining mandate set by the Public Sector Employers Council.

……

Planned salary increases for management and professional employees over the test period are 2.5 per cent per year which is similar to forecast inflation and market salary increases. While there is discretion in determining management and professional salary increase budgets, it would be difficult to continue to attract and retain employees if salaries do not increase over time and remain competitive with the market.

…….

As discussed in Section 5.6.5.2 of Chapter 5 of the Application, a 2017 assessment by Morneau Shepell concluded that BC Hydro's compensation package is 2 per cent below median market rates.

2.35.2.1 If planned salary increase for management and professional employees were 2% vs. 2.5% during the test period, what would be the financial savings to BC Hydro.

RESPONSE:

If planned salary increases for management and professional employees were 2 per cent instead of 2.5 per cent, it would result in operating cost savings of approximately $0.8 million in fiscal 2020 and $1.7 million in fiscal 2021. Capital and deferred savings would be approximately $0.5 million in fiscal 2020 and $1.1 million in fiscal 2021.

35.0 Topic: Operating Costs – Total Rewards Program

Reference: Exhibit B-1 Application, Section 5.2, Table 5-1, page 5-7, Section 5.6.5.2 Application; Exhibit B-5, BCUC IR 1.42.1, Exhibit B-6, Zone II RPG IR 1.8.1

BC Hydro states that:

A 2017 assessment by Morneau Shepell concluded that, on average total cash basis, BC Hydro employees earn 11 per cent less than median market rates.

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Affiliation	Standard Labour Hours	F2019 Forecast ($)	F2020 Plan ($)	F2021 Plan ($)
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Management and Professionals	1,621	97.66	100.69	102.48

In BC Hydro's response to BCUC IR 1.42.1, it states that:

Planned salary increases for union employees over the test period are 2 per cent per year which is consistent with the bargaining mandate set by the Public Sector Employers Council.

……

Planned salary increases for management and professional employees over the test period are 2.5 per cent per year which is similar to forecast inflation and market salary increases. While there is discretion in determining management and professional salary increase budgets, it would be difficult to continue to attract and retain employees if salaries do not increase over time and remain competitive with the market.

…….

As discussed in Section 5.6.5.2 of Chapter 5 of the Application, a 2017 assessment by Morneau Shepell concluded that BC Hydro's compensation package is 2 per cent below median market rates.

2.35.3 Provide the reference for the bargaining mandate of 2% for the Public Sector Employers Council.

RESPONSE:

The reference for the bargaining mandate can be found at the following Public Sector Employers' Council web site at: https://www2.gov.bc.ca/gov/content/employment-business/employers/public-sector-employers/public-sector-bargaining/mandates-and-agreements.

36.0 Topic: Operating Costs – Total Rewards Program

Reference: Exhibit B-5, IR 1.52.2, Exhibit B-6, Zone II RPG IR 1.8.3, 1.8.7

In its response to Zone II RPG 1.8.3, BC Hydro states that:

BC Hydro aims to align its total rewards offer to median market rates, as required by the Public Sector Employers' Council.

Additionally, BC Hydro's response to Zone II RPG 1.8.7 states:

The Public Sector Employers' Council requires that BC public sector employers, including BC Hydro, compare to the median market rate.

In its response to BCUC IR 1.52.2, BC Hydro states:

There were 15 market comparators used in the Morneau Shepell survey to determine pension, benefit and time off values. This included five Canadian electric utilities, five B.C. public sector organizations and five private sector organizations.

2.36.1 Provide the reference to the Public Sector Employers' Council's requirement that BC public sector employers compare to the median market rates.

RESPONSE:

The Public Sector Employers' Council guidelines regarding benchmarking can be found within their Guide to B.C. Public Sector Compensation and Expense Policies on their website at the link below.

https://www2.gov.bc.ca/assets/gov/british-columbians-our-governments/services-policies-for-government/public-sector-management/psec/public-sector-compensation-expense-policies-guidelines.pdf.

The requirement to compare to median market rates is not referenced in this guide; however BC Hydro has confirmed, in discussion with the Public Sector Employers' Council, that employers are expected to generally benchmark to no higher than the median rate.

36.0 Topic: Operating Costs – Total Rewards Program

Reference: Exhibit B-5, IR 1.52.2, Exhibit B-6, Zone II RPG IR 1.8.3, 1.8.7

In its response to Zone II RPG 1.8.3, BC Hydro states that:

BC Hydro aims to align its total rewards offer to median market rates, as required by the Public Sector Employers' Council.

Additionally, BC Hydro's response to Zone II RPG 1.8.7 states:

The Public Sector Employers' Council requires that BC public sector employers, including BC Hydro, compare to the median market rate.

In its response to BCUC IR 1.52.2, BC Hydro states:

There were 15 market comparators used in the Morneau Shepell survey to determine pension, benefit and time off values. This included five Canadian electric utilities, five B.C. public sector organizations and five private sector organizations.

2.36.2 Confirm, or explain otherwise, that all Public Sector Employers in BC are mandated by this requirement

RESPONSE:

Confirmed. All employers subject to Public Sector Employers' Council guidelines are expected to generally benchmark to no higher than the median market rate.

36.0 Topic: Operating Costs – Total Rewards Program

Reference: Exhibit B-5, IR 1.52.2, Exhibit B-6, Zone II RPG IR 1.8.3, 1.8.7

In its response to Zone II RPG 1.8.3, BC Hydro states that:

BC Hydro aims to align its total rewards offer to median market rates, as required by the Public Sector Employers' Council.

Additionally, BC Hydro's response to Zone II RPG 1.8.7 states:

The Public Sector Employers' Council requires that BC public sector employers, including BC Hydro, compare to the median market rate.

In its response to BCUC IR 1.52.2, BC Hydro states:

There were 15 market comparators used in the Morneau Shepell survey to determine pension, benefit and time off values. This included five Canadian electric utilities, five B.C. public sector organizations and five private sector organizations.

2.36.3 Confirm, or explain otherwise, that the five BC public sector included in the Morneau Shepell assessment are subject to the Public Employers' Council requirement to compare to the median market rate.

RESPONSE:

Not confirmed.

The Public Sector Employers' Council requirements apply to employers defined within the *Public Sector Employer Act*. While BC Hydro can't confirm which employers are bound by the *Public Sector Employers Act*, it is our assessment that one of the five B.C. public sector employers included in the Morneau Shepell assessment does not meet the definition while the other four employers do.

37.0 Topic: Operating Costs – Non-Integrated Area

Reference: Exhibit B-6, Zone II RPG IR 1.9.3

BC Hydro states that:

To support the development of a locally trained workforce in these areas, BC Hydro offer training and/or work experience programs.

In addition, contracts with non-local contractors may include a clause requiring the contractor to use local or indigenous resources or services as appropriate.

2.37.1 Confirm that BC Hydro offers free training to the NIA communities?

RESPONSE:

BC Hydro does not provide free training to everyone who requests it in NIA communities.

37.0 Topic: Operating Costs – Non-Integrated Area

Reference: Exhibit B-6, Zone II RPG IR 1.9.3

BC Hydro states that:

To support the development of a locally trained workforce in these areas, BC Hydro offer training and/or work experience programs.

In addition, contracts with non-local contractors may include a clause requiring the contractor to use local or indigenous resources or services as appropriate.

2.37.1 Confirm that BC Hydro offers free training to the NIA communities?

2.37.1.1 Provide details on the type of training provided.

RESPONSE:

BC Hydro looks to support candidates who are seeking employment with BC Hydro across a variety of career paths – from technical and trades, to business and customer services. Specific for the NIA area, candidates may access BC Hydro's Career Energizers - Trades program, or our Try a Trade program.

37.0 Topic: Operating Costs – Non-Integrated Area

Reference: Exhibit B-6, Zone II RPG IR 1.9.3

BC Hydro states that:

To support the development of a locally trained workforce in these areas, BC Hydro offer training and/or work experience programs.

In addition, contracts with non-local contractors may include a clause requiring the contractor to use local or indigenous resources or services as appropriate.

2.37.1 Confirm that BC Hydro offers free training to the NIA communities?

2.37.1.2 If so, what budget does this training cost fall under?

RESPONSE:

The training described in BC Hydro's response to ZONE II RPG IR 2.37.1.1 is funded from the Indigenous Employment and Training Department of the Indigenous Relations KBU.

37.0 Topic: Operating Costs – Non-Integrated Area

Reference: Exhibit B-6, Zone II RPG IR 1.9.3

BC Hydro states that:

To support the development of a locally trained workforce in these areas, BC Hydro offer training and/or work experience programs.

In addition, contracts with non-local contractors may include a clause requiring the contractor to use local or indigenous resources or services as appropriate.

2.37.2 Provide an explanation why BC Hydro does not include a clause requiring all contractors in NIA to hire local or indigenous resources or services as appropriate in its standard procurement contracts.

RESPONSE:

BC Hydro does not require all contractors in the NIA to hire local or Indigenous resources or services as there are situations where such a requirement may be inconsistent with other business needs or objectives. For example, in some cases, a local or Indigenous contractor will not have reasonable access to a pool of qualified candidates or services to perform the scope of work.

38.0 Topic: Operating Costs – Common Costs Department

Reference: Exhibit B-6, Zone II RPG IR 1.11.1

BC Hydro states in its response to Zone II RPG IR 1.11.1 that:

BC Hydro pays school tax and grants-in-lieu of taxes to the provincial and local government, but not to First Nations. BC Hydro established the Community Development Fund in 2001 to address this for First Nations who has BC Hydro transmission and distribution lines on their reserve lands.

2.38.1 Confirm that the school tax and grants-in-lieu of taxes for comparable sized communities are the same as those paid to First Nations under the Community Development Fund.

RESPONSE:

This answer also responds to ZONE II RPG IR 2.38.1.1.

Not confirmed. In general, there is no direct correlation between the size of a community and the amounts paid for school taxes and grants-in-lieu of taxes to municipalities or the amounts paid for the Community Development Fund to First Nations.

The amounts paid are linked to the amount of BC Hydro infrastructure located within a community, which does not necessarily correlate with the size of the community. For example:

- **BC Hydro has large generation facilities located in small communities (e.g., the GM Shrum and Peace Canyon generating stations are located in Hudson's Hope); and**
- **Many of our largest substations and high-voltage transmission lines are located in or pass through small rural communities.**

Only the location of BC Hydro's distribution infrastructure is driven by the size of a community as the amount of distribution infrastructure is tied to the number of customers in the area.

While BC Hydro makes Community Development Fund payments for distribution lines to First Nations based on their on-reserve population, this represents the smaller component of the total payments. The largest component of the Community Development Fund payments is for transmission lines and is based on the length and voltage of the circuits that pass through the reserve lands. Some small First Nations communities receive large payments as there are long lengths of high-voltage transmission lines passing through their reserve lands.

38.0 Topic: Operating Costs – Common Costs Department

Reference: Exhibit B-6, Zone II RPG IR 1.11.1

BC Hydro states in its response to Zone II RPG IR 1.11.1 that:

BC Hydro pays school tax and grants-in-lieu of taxes to the provincial and local government, but not to First Nations. BC Hydro established the Community Development Fund in 2001 to address this for First Nations who has BC Hydro transmission and distribution lines on their reserve lands.

2.38.1 Confirm that the school tax and grants-in-lieu of taxes for comparable sized communities are the same as those paid to First Nations under the Community Development Fund.

2.38.1.1 If not, explain the reasons for the differences.

RESPONSE:

Please refer to BC Hydro’s response to ZONE II RPG IR 2.38.1 where we explain the reasons for the differences.

38.0 Topic: Operating Costs – Common Costs Department

Reference: Exhibit B-6, Zone II RPG IR 1.11.1

BC Hydro states in its response to Zone II RPG IR 1.11.1 that:

BC Hydro pays school tax and grants-in-lieu of taxes to the provincial and local government, but not to First Nations. BC Hydro established the Community Development Fund in 2001 to address this for First Nations who has BC Hydro transmission and distribution lines on their reserve lands.

2.38.1 Confirm that the school tax and grants-in-lieu of taxes for comparable sized communities are the same as those paid to First Nations under the Community Development Fund.

2.38.1.2 List the communities that receive the funds and the annual amounts they receive.

RESPONSE:

The public version of the attachment has been redacted to maintain confidentiality over the specific payment amounts. The un-redacted version of the response is being made available to the BCUC only.

Attachment 1 to this response provides a list of First Nations that received Community Development Fund payments in fiscal 2019 and the amount of those payments.

B.C. HYDRO

2019 - FIRST NATIONS COMMUNITY DEVELOPMENT FUND

LIST OF PAYMENTS ISSUED

First Nation	Also Known As	Payment for 2019 ($)
Adams Lake Band	Sexqultqin	[redacted]
Aitchelitz First Nation		
Akisq'nuk First Nation	Columbia Lake	
Alexis Creek Indian Band	Tsi Del Del	
Ashcroft Indian Band		
Beecher Bay First Nation	Scia'new First Nation	
Bonaparte Indian Band		
Boothroyd Indian Band		
Boston Bar First Nation		
Burns Lake Band		
Campbell River Band	Wei Wai Kum First Nation	
Canim Lake Band		
Chawathil First Nation	Hope	
Cheam First Nation		
Cook's Ferry Indian Band		
Cowichan Tribes		
Ditidaht First Nation	Nitinaht	
Douglas First Nation (Xa'xtsa)	Xa'xtsa	
Ehattesaht First Nation		
Esdilagh Indian Band	Alexandria ; Tsilhqot'in National Govt	
Esk'etemc First Nation	Alkali Lake	
Esquimalt Nation		
Fort Nelson First Nation		
Gitanmaax Band		

B.C. HYDRO
2019 - FIRST NATIONS COMMUNITY DEVELOPMENT FUND
LIST OF PAYMENTS ISSUED

First Nation	Also Known As	Payment for 2019 ($)
Gitanyow Band	Kitwancool	[redacted]
Gitga'at	Hartley Bay	
Gitsegukla First Nation		
Gwa'Sala-Nakwaxda'xw Nation	Tsulquate	
Hagwilget Village Council		
Haisla First Nation	Kitamaat	
Halalt First Nation		
Heiltsuk Nation	Bella Bella	
Iskut Band Council		
Kanaka Bar Indian Band		
Katzie First Nation		
Kispiox Band		
Kitselas First Nation		
Kitsumkalum Band Council		
K'omoks Nation	Comox	
Kwakiutl Band Council		
Kwantlen First Nation	Fort Langley	
Kwaw Kwaw Apilt First Nation		
Kwikwetlem First Nation	Coquitlam	
Lax Kw'alaams Band	Port Simpson	
Leq'a:mel First Nation	Lakahahmen	
Lheidli T'enneh Band	Lheit Lit'en/Fort George	
Lhtako Dene Nation	Red Bluff	
Lil'wat Nation	Mount Currie	
Little Shuswap Lake Indian Band		

B.C. HYDRO
2019 - FIRST NATIONS COMMUNITY DEVELOPMENT FUND
LIST OF PAYMENTS ISSUED

First Nation	Also Known As	Payment for 2019 ($)
Lower Kootenay Indian Band		[redacted]
Lower Nicola Indian Band		
Lytton First Nation		
Malahat First Nation		
McLeod Lake Indian Band		
Moricetown Band	Witset First Nation	
Mowachaht/Muchalaht First Nation		
Musqueam Indian Band		
Nadleh Whuten First Nation	Fraser Lake	
Nak'azdli Whut'en	Necoslie	
Namgis First Nation	Nimpkish	
Nanoose First Nation	Snaw-Naw-As	
Nazko First Nation		
Neskonlith Indian Band		
Nicomen Indian Band		
Nooaitch Indian Band		
N'Quatqua First Nation	Anderson Lake	
Nuchatlaht Indian Band		
Okanagan Indian Band		
Old Massett Village Council		
Oregon Jack Creek Band		
Osoyoos Indian Band		
Pauquachin First Nation		
Penelakut Tribe		

B.C. HYDRO
2019 - FIRST NATIONS COMMUNITY DEVELOPMENT FUND
LIST OF PAYMENTS ISSUED

First Nation	Also Known As	Payment for 2019 ($)
Penticton Indian Band		[redacted]
Peters Band		[redacted]
Popkum Band		[redacted]
Prophet River Band	Dene Tsaa Tse K'Nai	[redacted]
Qualicum First Nation		[redacted]
Quatsino First Nation		[redacted]
Samahquam First Nation		[redacted]
Seabird Island Band		[redacted]
Sekw'elw'as First Nation	Cayoose Creek	[redacted]
Shackan Indian Band		[redacted]
Shuswap Indian Band		[redacted]
Shxwha:y Village	Skway	[redacted]
Shxw'ow'hamel First Nation	Ohamil	[redacted]
Sik-e-dakh (Glen Vowell Band)	Sikokoak	[redacted]
Simpcw First Nation	North Thompson	[redacted]
Siska Indian Band		[redacted]
Skatin Nations	Skookumchuk	[redacted]
Skawahlook First Nation		[redacted]
Skeetchestn Indian Band	Deadman's Creek	[redacted]
Skidegate Band Council		[redacted]
Skin Tyee Nation		[redacted]
Skowkale First Nation		[redacted]
Skuppah Indian Band		[redacted]
Skwah First Nation		[redacted]

B.C. HYDRO
2019 - FIRST NATIONS COMMUNITY DEVELOPMENT FUND
LIST OF PAYMENTS ISSUED

First Nation	Also Known As	Payment for 2019 ($)
Snuneymuxw First Nation	Nanaimo	[redacted]
Songhees First Nation		
Soowahlie First Nation		
Splatsin First Nation	Spallumcheen	
Spuzzum First Nation		
Squamish Nation		
Squiala First Nation		
St. Mary's Indian Band	?aqam	
Stellat'en First Nation	Stellaquo	
Sts'ailes	Chehalis	
Stswecem'c Xgat'tem First Nation	Canoe Creek	
Stz'uminus First Nation	Chemainus First Nation	
Sumas First Nation		
Tahltan Indian Band		
Taku River Tlingit First Nation	Atlin	
T'it'q'et	Lillooet	
Tk'emlúps te Secwèpemc	Kamloops	
Tl'azt'en Nation	Stuart-Trembleur	
Tl'etinqox-t'in Government Office	Anahim	
Tobacco Plains Indian Band		
Toosey Indian Band		
Tsal'alh	Seton Lake	
Tsartlip First Nation		
Tsawout First Nation		

B.C. HYDRO
2019 - FIRST NATIONS COMMUNITY DEVELOPMENT FUND
LIST OF PAYMENTS ISSUED

First Nation	Also Known As	Payment for 2019 ($)
Tseshaht First Nation		[redacted]
Tseycum First Nation		
Ts'kw'aylaxw First Nation	Pavilion	
Tsleil-Waututh First Nation	Burrard	
T'Sou-ke First Nation	Sooke	
Tzeachten First Nation		
We Wai Kai First Nation	Cape Mudge	
West Moberly First Nations		
Westbank First Nation		
Wet'suwet'en First Nation	Broman Lake	
Williams Lake Indian Band	Sugar Cane	
Xaxli'p First Nations	Fountain	
Xwisten (Bridge River)	Bridge River Indian Band	
Yale First Nation		
Yekooche First Nation		
Yunesit'in Government	Stone Band	
TOTAL		

39.0 Topic: Operating Costs – Indigenous Relations

Reference: Exhibit B-6, Zone II RPG IR 1.12.1

In response to Zone II RPG IR 1.12.1, BC Hydro provided its Statement of Indigenous Principles which contains the following statement: "To support our move towards true and lasting reconciliation with Indigenous Peoples, BC Hydro will acknowledge past wrongs, listen to Indigenous perspectives and seek shared understanding with First Nations communities and governments."

2.39.1 Please indicate how BC Hydro's commitment to reconciliation to the Zone II RPG communities (Kwadacha/Fort Ware and Tsay Keh Dene) was taken into account in this revenue requirements application.

RESPONSE:

BC Hydro believes that reconciliation is an ongoing commitment with no pre-defined end point. Our understanding of the steps we will take to advance reconciliation is developed jointly with First Nations.

Specific ongoing activities that will demonstrate BC Hydro's commitment to reconciliation with Kwadacha and Tsay Keh Dene include:

- **Employee continuity for key roles – The Indigenous Relations KBU has taken steps to avoid turn-over of employees who work directly with the Nations. An important example of this is that the Relationship Lead for these communities has remained consistent for the past four years. The continuity in employees supports the development of a deeper understanding of the Nations interests and ensures that we are incorporating their interests into our business activities;**
- **Developing cultural awareness – There are frequent opportunities for BC Hydro to improve employee awareness across the company including:**
  - **"Kwadacha by the River" is a documentary produced by the Kwadacha Nation and funded by BC Hydro. All new BC Hydro employees view the film trailer as part of their onboarding and are encouraged to view the full film. The film supports the ongoing dialogue about the impacts of BC Hydro's infrastructure on First Nation communities and it provides an opportunity for new employees to discuss and explore what reconciliation means to them through supportive facilitation; and**

- ▶ **BC Hydro has developed two levels of Indigenous Awareness training based on the various needs of employees across the company. Due to their role in the company, some employees complete an online training module. Other employees require a more in depth level of training which is achieved through a half-day session that is delivered by an Indigenous employee. Indigenous Awareness training is available to all employees;**

- **Clean energy development – Please refer to BC Hydro's response to ZONE II RPG IR 2.39.2 for a discussion of how our commitment to reconciliation is being pursued in relation to clean energy development; and**

- **Demand Side Management – Please refer to BC Hydro's response to ZONE II RPG IR 2.40.1 for a discussion of how our commitment to reconciliation is being supported through our Demand Side Management program.**

For a high-level summary of the terms of reference related to reconciliation with Indigenous Peoples, as part of the Phase Two of the Comprehensive Review of BC Hydro, please refer to BC Hydro's response to INCE IR 2.30.0.

Zone II Ratepayers Group Information Request No. **2.39.2** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

39.0 Topic: Operating Costs – Indigenous Relations

Reference: Exhibit B-6, Zone II RPG IR 1.12.1

In response to Zone II RPG IR 1.12.1, BC Hydro provided its Statement of Indigenous Principles which contains the following statement: “To support our move towards true and lasting reconciliation with Indigenous Peoples, BC Hydro will acknowledge past wrongs, listen to Indigenous perspectives and seek shared understanding with First Nations communities and governments.”

2.39.2 Please indicate how BC Hydro’s commitment to reconciliation is being administered or pursued in relation to clean energy development, especially in Zone II RPG.

RESPONSE:

In keeping with BC Hydro’s commitment to reconciliation, we recognize the importance of clean energy development to First Nation communities. BC Hydro is working closely with Zone II RPG communities to respond to their interests. An example of this includes BC Hydro’s work with the Kwadacha First Nation to enter into an Electricity Purchase Agreement (EPA) for a biomass project that provides clean energy to Fort Ware and reduces reliance on diesel generation in the community. By Order No. E-5-16, the BCUC accepted the EPA and the project commenced operations in April 2017. BC Hydro continues to work with Kwadacha to identify and address challenges with project implementation.

40.0 Topic: Operating Costs – Indigenous Relations

Reference: Exhibit B-6, Zone II RPG IR 1.12.1

In response to Zone II RPG IR 1.12.1, BC Hydro provided its Statement of Indigenous Principles which contains the following statement: "To support our move towards true and lasting reconciliation with Indigenous Peoples, BC Hydro will acknowledge past wrongs, listen to Indigenous perspectives and seek shared understanding with First Nations communities and governments."

Section 44.2 of the *Utilities Commission Act* requires the BCUC to accept a DSM expenditure schedule if it considers that making expenditures would be in the public interest. According to s. 44.2(5), considerations include "the interests of persons in British Columbia who receive or may receive service from the public utility."

2.40.1 Please indicate how BC Hydro considers its DSM plan to be in the interests of Zone II RPG residents, and specifically Indigenous communities like Kwadacha/Fort Ware and Tsay Keh Dene, including how BC Hydro's DSM plan takes into account BC Hydro's commitment to pursuing reconciliation?

RESPONSE:

BC Hydro believes that reconciliation is an ongoing commitment with no pre-defined end point. Our understanding of the steps we will take to advance reconciliation is developed jointly with First Nations. BC Hydro considers its DSM plan and activities to be in the interests of Zone II customers in the Kwadacha / Fort Ware and Tsay Keh Dene communities, because:

- **BC Hydro's new Non-Integrated Area (NIA) DSM program supports Indigenous communities in undertaking home energy upgrades that reduce electricity consumption and costs, while improving home comfort. This work supports reductions in greenhouse gas emissions from diesel-generated electricity, which benefits air quality and climate;**
- **A new program delivery model provides training and salary support to enable Indigenous communities to lead their own home energy upgrades, an approach which we feel supports Indigenous rights to autonomy and self-determination; and**
- **Support for training and capacity development through our DSM Codes and Standards initiative further contributes to BC Hydro's efforts to advance**

reconciliation with First Nation communities, including Kwadacha and Tsay Keh Dene.

For more information about the new and enhanced DSM measures available through the NIA DSM program, please refer to BC Hydro's response to ZONE II RPG IR 2.47.4.

41.0 Topic: Operating Costs – People, Customer, Corporate Affairs Business Group

Reference: Exhibit B-6, Zone II RPG IR 1.15.1

BC Hydro states in its response to Zone II RPG IR 1.15.1:

Depending on the community, barriers to providing effective customer service to Non-Integrated Area communities may include:

- availability of internet to view and pay bills online;
- timeliness of Canada Post services; and
- lack of access to local banks or other payment providers.

2.41.1 What actions, if any, is BC Hydro undertaking to remove or mitigate these barriers for NIA communities in F2020 – F2021?

RESPONSE:

BC Hydro's response to ZONE II RPG IR 1.15.1.1 described examples of actions BC Hydro has taken to address or remove barriers that impact low income customers and those in Non-Integrated Area communities. In addition to those examples:

- **In Fiscal 2019, BC Hydro worked with its third-party payment provider (Paymentus) to offer Visa Debit and Debit Mastercard as additional payment methods. Customers are charged a flat fee of $0.75 for a debit payment (up to $1,000) as compared to a transaction charge of 1.75 per cent for a credit card payment. As a result, adding debit payment options can reduce the transaction cost for customers in all regions that choose not to make payments through their banks (in-person, online or telephone banking) or mail cheques to BC Hydro; and**

- **In 2017, BC Hydro made iPads available in the Kwadacha Nation and Tsay Keh Dene Nation band offices to enable community members to access online bills and make payments.**

BC Hydro does not currently have plans in Fiscal 2020 or Fiscal 2021 to provide further internet access to facilitate online billing in Non-Integrated Area communities, or to further expand payment options generally.

42.0 Topic: Capital Expenditures – Non-Integrated Areas

Reference: Exhibit B-6, Zone II RPG IR 1.17.1

BC Hydro states that:

No capital expenditures for the non-integrated areas were deferred or reduced in the Capital Plan in the Application as the CleanBC Remote Community Clean Energy Strategy was announced after the currency date of the Capital Plan. BC Hydro monitors its capital plan on an ongoing basis and adjustments can be made to re-direct the capital budget, as new information becomes available. Some capital expenditures in the non-integrated areas may be deferred as new renewable energy projects are realized in the non-integrated communities, through the CleanBC Remote Community Clean Energy Strategy.

2.42.1 Provide details on the CleanBC Remote Community Clean Strategy, including BC Hydro's involvement and forecast expenditures.

RESPONSE:

Please refer to section 2.2.3 of Government of B.C.'s CleanBC plan[1] for a description of the Government's Remote Community Clean Energy Strategy (RCCES).

BC Hydro's involvement with RCCES is expected to primarily be through diesel reduction activities in our Non-Integrated Areas. Please refer to BC Hydro's response to ZONE II RPG IR 1.4.1 for a discussion of the status of BC Hydro's approach to these diesel reduction activities.

BC Hydro does not currently have any forecast expenditures associated with RCCES. Ongoing coordination with Government on RCCES is provided by existing BC Hydro resources. Implementation of any potential future projects directly associated with RCCES would likely be funded via BC Hydro's DSM program, BC Hydro capital projects, or Electricity Purchase Agreements.

[1] **https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/cleanbc_2018-bc-climate-strategy.pdf**

43.0 Topic: Demand-Side Management – DSM Program Spend by Sector

Reference: Exhibit B-6, Zone II RPG IR 1.19.2

In BC Hydro's response to Zone II RPG IR 1.19.2, BC Hydro states:

BC Hydro did not target a specific level of DSM Program spending for the residential sector relative to other sectors. Rather, BC Hydro created enhanced program offers to address affordability in the residential sector and then estimated the budget that would be required to deliver these programs. The outcome of this process was to increase the level of DSM expenditures for the residential sector to 30 per cent of the total DSM Program spending.

2.43.1 Provide a list and details on all the new enhanced DSM program offers for the test period.

RESPONSE:

The table below summarizes the changes made to the Home Renovation Rebate Program beginning in fiscal 2019.

Measure	Offer Prior to Q3 F2019	Offer Starting in Q3 F2019
Ductless air source heat pump	$800	$1,000
Central air source heat pump (new measure)	n/a	$2,000
Windows Tier 1 (new measure)	n/a	$50
Windows Tier 2	$50	$100
Ventilation Fan	$25	$25
Smart Thermostat (new measure)	n/a	$50
Heat Pump Water Heater (new measure)	n/a	$1,000
Attic Insulation	$.02 x R-Value added x sq ft ($600 max)	$.02 x R-Value added x sq ft ($900 max)
Exterior Wall Insulation	$.08 x R-Value added x sq ft ($1,200 max)	$.09 x R-Value added x sq ft ($1,200 max)
Basement/Crawl Insulation	$.08 x R-Value added x sq ft ($1,000 max)	$.09 x R-Value added x sq ft ($1,200 max)
Insulation Other	$.05 x R-Value added x sq ft ($450 max)	$.07 x R-Value added x sq ft ($1,000 max)

The table below summarizes the changes made to the Low Income Program beginning in fiscal 2019.

Measure	Offer Prior to test period	Offer Starting in test period
Refrigerator Replacement	Only offered in ECAP Basic	Expanded offer to Apartments
Attic Insulation	Existing insulation must be very low	Existing insulation must be moderate
Insulation for Manufactured Homes	Not offered	Offered via ECAP Weatherization
Window Film	Offered once every 5 years via ESK	Offered annually
Programmable Thermostat	Not offered	Offered via ECAP Weatherization
Drying Racks/Clothesline	Not offered	Offered via ECAP Basic
LED Specialty Bulbs	Not offered	Offered via ECAP Basic

BC Hydro also launched a new Non-Integrated Areas program in fiscal 2019 and allocated additional budget to our Low Income Program to support Indigenous communities in the integrated area with the same offer and process.

Details on the Non-Integrated Areas program offer can be found in BC Hydro's response to ZONE II RPG IR 2.47.4.1.

43.0 Topic: Demand-Side Management – DSM Program Spend by Sector

Reference: Exhibit B-6, Zone II RPG IR 1.19.2

In BC Hydro's response to Zone II RPG IR 1.19.2, BC Hydro states:

BC Hydro did not target a specific level of DSM Program spending for the residential sector relative to other sectors. Rather, BC Hydro created enhanced program offers to address affordability in the residential sector and then estimated the budget that would be required to deliver these programs. The outcome of this process was to increase the level of DSM expenditures for the residential sector to 30 per cent of the total DSM Program spending.

2.43.1 Provide a list and details on all the new enhanced DSM program offers for the test period.

2.43.1.1 Confirm or explain otherwise if these program offerings will be permanent and continuing DSM offerings for the residential sector.

RESPONSE:

BC Hydro has included these offers in its longer-term DSM Plan and expects that they will continue. BC Hydro's DSM Plan may be adjusted in response to factors such as changing market conditions, participation or resource planning decisions.

43.0 Topic: Demand-Side Management – DSM Program Spend by Sector

Reference: Exhibit B-6, Zone II RPG IR 1.19.2

In BC Hydro's response to Zone II RPG IR 1.19.2, BC Hydro states:

BC Hydro did not target a specific level of DSM Program spending for the residential sector relative to other sectors. Rather, BC Hydro created enhanced program offers to address affordability in the residential sector and then estimated the budget that would be required to deliver these programs. The outcome of this process was to increase the level of DSM expenditures for the residential sector to 30 per cent of the total DSM Program spending.

2.43.2 Provide details on why BC Hydro chose these specific programs to address affordability in the residential sector.

RESPONSE:

The residential programs chosen for enhanced offers were the Home Renovation Rebate Program and the Low Income Program. In addition, the Non-Integrated Areas program was launched. BC Hydro chose these programs to address affordability because:

- **The Home Renovation Rebate Program focuses on customers that have electric heat, who can make their electricity bills more affordable by reducing their space heating load. Customers with electric heating typically have higher electricity consumption and higher bills, with heating normally accounting for 50 per cent of their energy consumption;**
- **The Low Income Program's purpose is to help BC Hydro's lower income customers reduce their energy consumption and their BC Hydro bills. The program has a target market defined as customers that have a household income that is less than the federal Low Income Cut-Off measure plus 30 per cent; and**
- **The new Non-Integrated Areas (NIA) program combines elements from the Low Income Program and the Home Renovation Rebate Program, and adapts them for customers living in non-integrated areas of BC Hydro's service territory. The program aims to improve affordability for customers in these remote areas.**

43.0 Topic: Demand-Side Management – DSM Program Spend by Sector

Reference: Exhibit B-6, Zone II RPG IR 1.19.2

In BC Hydro's response to Zone II RPG IR 1.19.2, BC Hydro states:

BC Hydro did not target a specific level of DSM Program spending for the residential sector relative to other sectors. Rather, BC Hydro created enhanced program offers to address affordability in the residential sector and then estimated the budget that would be required to deliver these programs. The outcome of this process was to increase the level of DSM expenditures for the residential sector to 30 per cent of the total DSM Program spending.

2.43.2 Provide details on why BC Hydro chose these specific programs to address affordability in the residential sector.

2.43.2.1 Provide details on why BC Hydro did not offer these programs previously.

RESPONSE:

The primary factors that led BC Hydro to explore enhancements to its Low Income Program and Home Renovation Rebate Program, and to introduce the Non-Integrated Areas Program, were:

- **Directive 21 of the BCUC's Decision on the Previous Application, which asked BC Hydro to consider more targeted DSM programs directed at residential customers;**
- **BC Hydro's Mandate Letter from the Government of B.C. which directed BC Hydro to implement affordability measures, such as expanded demand-side management programs targeted to low income ratepayers;**
- **Directive 23 of the BCUC's Decision on the Previous Application, which asked BC Hydro to provide an update of how BC Hydro has addressed concerns raised by non-integrated area customer groups; and**
- **With respect to the Non-integrated Areas Program, information from pilot activities was needed to inform the full-scale program.**

44.0 Topic: Demand-Side Management – Low Income Advisory Council

Reference: Exhibit B-6, Zone II RPG IR 1.20.1.1

In its response to Zone II RPG IR 1.20.1.2, BC Hydro lists the groups represented on the Low Income Advisory Council including the Zone II Ratepayers Group.

2.44.1 Provide details on how BC Hydro is engaging with Zone II RPG within the Low Income Advisory Council as well as within the individual communities.

RESPONSE:

BC Hydro utilizes the Low Income Advisory Council as a way to engage in ongoing dialogue with low income advocacy groups and stakeholders. Low Income Advisory Council meetings are generally scheduled quarterly.

Prior to each meeting, BC Hydro solicits the Low Income Advisory Council members for topics that they would like to discuss at Low Income Advisory Council meetings. BC Hydro then identifies a representative from the responsible Department to attend the meeting and respond to the members' request. In addition, members of BC Hydro's Executive Team may attend the meetings. For example, BC Hydro's President and Chief Operating Officer has attended one of the quarterly meetings in each of the last two years. BC Hydro also proposes topics for discussion to obtain feedback on specific issues, or to create awareness of new or modified programs and business practices.

Materials are distributed to members prior to each meeting. BC Hydro's response to ZONE II RPG IR 1.20.1.2 included examples of topics discussed with the Low Income Advisory Council.

BC Hydro engages with the Low Income Advisory Council to improve its understanding of issues faced by low income customers. As Low Income Advisory Council members represent diverse groups of stakeholders that may have differing viewpoints and opinions, the group does not always achieve consensus on topics being discussed.

Action items and summary of discussions are recorded. BC Hydro assesses the feedback from Low Income Advisory Council members and evaluates whether suggestions are aligned with BC Hydro's objectives and priorities as well as cost and implementation requirements.

BC Hydro implements some suggestions immediately (e.g., improvements to the Customer Crisis Fund grant application form) while other feedback and suggestions are taken into consideration as BC Hydro develops its annual work plans.

44.0 Topic: Demand-Side Management – Low Income Advisory Council

Reference: Exhibit B-6, Zone II RPG IR 1.20.1.1

In its response to Zone II RPG IR 1.20.1.2, BC Hydro lists the groups represented on the Low Income Advisory Council including the Zone II Ratepayers Group.

2.44.2 Provide details on the process whereby specific issues brought forward at the LIAC are followed up for further review and implementation by BC Hydro.

RESPONSE:

Please refer to BC Hydro's response to ZONE II RPG IR 2.44.1 where we discuss how BC Hydro considers specific issues brought forward at the Low Income Advisory Council.

45.0 Topic: Demand-Side Management – Low Income Advisory Council

Reference: Exhibit B-6, Zone II RPG 1.20.3, 1.20.3.2

In BC Hydro's response to Zone II RPG IR 1.20.3, BC Hydro describes the potential barriers in the design of the DSM programs and the actions BC Hydro is taking to help address or mitigate these barriers.

BC Hydro also states that:

Providing rebates for home energy upgrade measures so that Bands can combine funding from other agencies and deliver energy efficiency improvements concurrent with other home renovations. These rebates are higher than those available through our existing Home Renovation Rebate program in order to support affordability for Indigenous communities.

We believe the activities we are undertaking are helping to reduce these barriers. In some cases, our activities may be able to reduce barriers more easily or quickly, such as providing free energy saving products in order to overcome affordability barriers. In other cases, overcoming barriers will require sustained effort over time, such as building awareness of conservation and energy management through education and training.

2.45.1 Confirm, or explain otherwise, that rebates are higher for the Indigenous Customer Offer in recognition that costs are higher to deliver DSM in remote communities.

RESPONSE:

Rebates are higher for certain measures in the Indigenous Customer Offer, recognizing that costs to deliver DSM are higher in remote communities. Please refer to BC Hydro's response to ZONE II RPG IR 2.47.4 for details on the measures and rebates.

45.0 Topic: Demand-Side Management – Low Income Advisory Council

Reference: Exhibit B-6, Zone II RPG 1.20.3, 1.20.3.2

In BC Hydro's response to Zone II RPG IR 1.20.3, BC Hydro describes the potential barriers in the design of the DSM programs and the actions BC Hydro is taking to help address or mitigate these barriers.

BC Hydro also states that:

Providing rebates for home energy upgrade measures so that Bands can combine funding from other agencies and deliver energy efficiency improvements concurrent with other home renovations. These rebates are higher than those available through our existing Home Renovation Rebate program in order to support affordability for Indigenous communities.

We believe the activities we are undertaking are helping to reduce these barriers. In some cases, our activities may be able to reduce barriers more easily or quickly, such as providing free energy saving products in order to overcome affordability barriers. In other cases, overcoming barriers will require sustained effort over time, such as building awareness of conservation and energy management through education and training.

2.45.2 Identify any potential barriers that BC Hydro has identified specifically for Zone II RPG communities.

RESPONSE:

BC Hydro's response to ZONE II RPG IR 1.20.3 identifies the barriers that we considered in the design of our new Demand-Side Management (DSM) program for Indigenous communities on both the integrated system and in the Non-Integrated Area (NIA). While the magnitude of these barriers may vary from community to community, BC Hydro believes these barriers are applicable to the Zone II Ratepayers Group communities. If there are other potential barriers that the Zone II Ratepayers Group would like us to consider, we are always open to learning about these and working with our customers and partners to try and find ways to address them.

45.0 Topic: Demand-Side Management – Low Income Advisory Council

Reference: Exhibit B-6, Zone II RPG 1.20.3, 1.20.3.2

In BC Hydro's response to Zone II RPG IR 1.20.3, BC Hydro describes the potential barriers in the design of the DSM programs and the actions BC Hydro is taking to help address or mitigate these barriers.

BC Hydro also states that:

Providing rebates for home energy upgrade measures so that Bands can combine funding from other agencies and deliver energy efficiency improvements concurrent with other home renovations. These rebates are higher than those available through our existing Home Renovation Rebate program in order to support affordability for Indigenous communities.

We believe the activities we are undertaking are helping to reduce these barriers. In some cases, our activities may be able to reduce barriers more easily or quickly, such as providing free energy saving products in order to overcome affordability barriers. In other cases, overcoming barriers will require sustained effort over time, such as building awareness of conservation and energy management through education and training.

2.45.2 Identify any potential barriers that BC Hydro has identified specifically for Zone II RPG communities.

2.45.2.1 How are BC Hydro's actions and activities reducing those barriers?

RESPONSE:

As stated in BC Hydro's response to ZONE II RPG IR 2.45.2, we believe the barriers for Zone II Ratepayers Group communities are similar to the barriers for Indigenous Communities on both the integrated system and the Non-Integrated Areas. BC Hydro believes the activities we are undertaking are helping to reduce these barriers. If there are other potential activities that the Zone II Ratepayers Group would like us to consider, we are always open to working with our customers and partners to try and find ways to further address barriers.

46.0 Topic: Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Chapter 10, Table 10-5, Appendix X, Appendix A, Table A-8; Exhibit B-5, BCUC IR 1.185.2, Exhibit B-6, Zone II RPG IR 1.21.1, IR 1.26.8

On page 1-12 of Chapter 10 of its F2020 – F2021 Application, BC Hydro provides the following table and Table A-8 on page 8 of 8 in Appendix A of Appendix X of the Application:

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

BC Hydro's response to BCUC IR 1.185.2 provides the following correction:

In preparing its response to this IR, BC Hydro discovered an error in its calculation of the Total Resource Cost (TRC) test for the Non-Integrated Areas program for the fiscal 2020 to fiscal 2022 period. The benefit-cost ratios in Table 10-5 of Chapter 10 of the Application are corrected in the table below.

	Net Levelized Cost (non-integrated areas) ($/MWh)	Benefit-Cost Ratio (non-integrated areas)
Total Resource Cost	159	1.9

In its response to Zone II RPG 1.21.1, BC Hydro clarifies that:

The cost effectiveness comparison information in Table 10-5 of Chapter 10 of the Application is for fiscal 2020 to fiscal 2022.

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	**$40**	**$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**

In its response to Zone II RPG IR 1.26.8, BC Hydro provides details on the Community Support to *provide financial and technical resources to support them in pursuing energy upgrades*. *This includes:*

- **Salary support to Indigenous Bands to hire community members who will visit homes in the community to review energy upgrade opportunities and install basic energy saving products.**
- **Training for these community members on how to review energy upgrade opportunities and install basic energy saving measures in homes.**
- **Training to Indigenous Bands that are planning to lead their own home renovation work and participate in our residential rebates. This training will be based on the Best Practice Guide: Air Sealing and Insulation Retrofits for Single Family Homes (2018 Second Edition).**
- **Other support as necessary to encourage energy upgrades and conservation behaviours in the community (e.g., presentations at community meetings, Elder and youth engagement, engagement with facility managers, etc.).**

2.46.1 Calculate Table 10-5 for the test period (F2020 – F2021).

RESPONSE:

The table below revises the comparison provided in Table 10-5 of Chapter 10 of the Application, based on fiscal 2020 to fiscal 2021 results. The calculations have been updated to remove the Thermo-Mechanical Pulp program activities in fiscal 2021, consistent with the updated DSM expenditure request provided in BC Hydro's Evidentiary Update.

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	**180**	**1.8**	**10**	**1.8**
Total Resource Cost	**163**	**1.9**	**-20**	**3.8**

46.0 Topic: Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Chapter 10, Table 10-5, Appendix X, Appendix A, Table A-8; Exhibit B-5, BCUC IR 1.185.2, Exhibit B-6, Zone II RPG IR 1.21.1, IR 1.26.8

On page 1-12 of Chapter 10 of its F2020 – F2021 Application, BC Hydro provides the following table and Table A-8 on page 8 of 8 in Appendix A of Appendix X of the Application:

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

BC Hydro's response to BCUC IR 1.185.2 provides the following correction:

In preparing its response to this IR, BC Hydro discovered an error in its calculation of the Total Resource Cost (TRC) test for the Non-Integrated Areas program for the fiscal 2020 to fiscal 2022 period. The benefit-cost ratios in Table 10-5 of Chapter 10 of the Application are corrected in the table below.

	Net Levelized Cost (non-integrated areas) ($/MWh)	Benefit-Cost Ratio (non-integrated areas)
Total Resource Cost	**159**	**1.9**

In its response to Zone II RPG 1.21.1, BC Hydro clarifies that:

The cost effectiveness comparison information in Table 10-5 of Chapter 10 of the Application is for fiscal 2020 to fiscal 2022.

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	$66	-$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	**$40**	**$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**

In its response to Zone II RPG IR 1.26.8, BC Hydro provides details on the Community Support to *provide financial and technical resources to support them in pursuing energy upgrades*. *This includes:*

- **Salary support to Indigenous Bands to hire community members who will visit homes in the community to review energy upgrade opportunities and install basic energy saving products.**
- **Training for these community members on how to review energy upgrade opportunities and install basic energy saving measures in homes.**
- **Training to Indigenous Bands that are planning to lead their own home renovation work and participate in our residential rebates. This training will be based on the Best Practice Guide: Air Sealing and Insulation Retrofits for Single Family Homes (2018 Second Edition).**
- **Other support as necessary to encourage energy upgrades and conservation behaviours in the community (e.g., presentations at community meetings, Elder and youth engagement, engagement with facility managers, etc.).**

2.46.2 Revise Table A-8 to reflect the error noted in BC Hydro's response to BCUC IR 1.185.2.

RESPONSE:

A revised Table A-8 that corrects for the error noted in BC Hydro's response to BCUC IR 1.185.2 and removes the Thermo-Mechanical Pulp program activities in fiscal 2021, consistent with the updated DSM expenditure request provided in BC Hydro's Evidentiary Update is provided below.

Zone II Ratepayers Group Information Request No. **2.46.2** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 4 of 4
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit: B-13**

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	-$15	$0	$0	$0	$0	$0	$0	$0	$159	$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*	*-$22*	*$0*	*-$4*	*$0*	*-$28*	*-$28*	*-$5*	*-$5*	*$13*	*$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	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Industrial Sector Total	*$38*	*$23*	*-$49*	*$0*	*$0*	*$0*	*-$8*	*-$8*	*-$2*	*-$2*	-$22	$12
Total Programs	**$50**	**$26**	**-$49**	**$0**	**-$3**	**$0**	**-$14**	**-$14**	**-$2**	**-$2**	**-$18**	**$10**
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]	**$71**	**$43**	**-$42**	**$0**	**-$2**	**$0**	**-$13**	**-$13**	**-$2**	**-$2**	**$11**	**$27**

Notes:

1. Levelized costs are based on expenditures and energy savings from fiscal 2020 – 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.

46.0 Topic: Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Chapter 10, Table 10-5, Appendix X, Appendix A, Table A-8; Exhibit B-5, BCUC IR 1.185.2, Exhibit B-6, Zone II RPG IR 1.21.1, IR 1.26.8

On page 1-12 of Chapter 10 of its F2020 – F2021 Application, BC Hydro provides the following table and Table A-8 on page 8 of 8 in Appendix A of Appendix X of the Application:

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

BC Hydro's response to BCUC IR 1.185.2 provides the following correction:

In preparing its response to this IR, BC Hydro discovered an error in its calculation of the Total Resource Cost (TRC) test for the Non-Integrated Areas program for the fiscal 2020 to fiscal 2022 period. The benefit-cost ratios in Table 10-5 of Chapter 10 of the Application are corrected in the table below.

	Net Levelized Cost (non-integrated areas) ($/MWh)	Benefit-Cost Ratio (non-integrated areas)
Total Resource Cost	**159**	**1.9**

In its response to Zone II RPG 1.21.1, BC Hydro clarifies that:

The cost effectiveness comparison information in Table 10-5 of Chapter 10 of the Application is for fiscal 2020 to fiscal 2022.

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
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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	**$40**	**$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**

In its response to Zone II RPG IR 1.26.8, BC Hydro provides details on the Community Support to *provide financial and technical resources to support them in pursuing energy upgrades. This includes:*

- **Salary support to Indigenous Bands to hire community members who will visit homes in the community to review energy upgrade opportunities and install basic energy saving products.**
- **Training for these community members on how to review energy upgrade opportunities and install basic energy saving measures in homes.**
- **Training to Indigenous Bands that are planning to lead their own home renovation work and participate in our residential rebates. This training will be based on the Best Practice Guide: Air Sealing and Insulation Retrofits for Single Family Homes (2018 Second Edition).**
- **Other support as necessary to encourage energy upgrades and conservation behaviours in the community (e.g., presentations at community meetings, Elder and youth engagement, engagement with facility managers, etc.).**

2.46.3 Confirm, or explain otherwise, that the Net Levelized Cost and Benefit-Cost Ratio for the integrated system programs in Table 10-5 refers to DSM residential sector programs in the integrated system.

RESPONSE:

Not confirmed. The net levelized cost and benefit-cost ratios for the integrated system programs in Table 10-5 of Chapter 10 of the Application include residential, commercial and industrial integrated system programs.

46.0 Topic: Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Chapter 10, Table 10-5, Appendix X, Appendix A, Table A-8; Exhibit B-5, BCUC IR 1.185.2, Exhibit B-6, Zone II RPG IR 1.21.1, IR 1.26.8

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Total Resource Cost	117	2.2	-11	3.6

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In preparing its response to this IR, BC Hydro discovered an error in its calculation of the Total Resource Cost (TRC) test for the Non-Integrated Areas program for the fiscal 2020 to fiscal 2022 period. The benefit-cost ratios in Table 10-5 of Chapter 10 of the Application are corrected in the table below.

	Net Levelized Cost (non-integrated areas) ($/MWh)	Benefit-Cost Ratio (non-integrated areas)
Total Resource Cost	159	1.9

In its response to Zone II RPG 1.21.1, BC Hydro clarifies that:

The cost effectiveness comparison information in Table 10-5 of Chapter 10 of the Application is for fiscal 2020 to fiscal 2022.

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	**$40**	**$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**

In its response to Zone II RPG IR 1.26.8, BC Hydro provides details on the Community Support to *provide financial and technical resources to support them in pursuing energy upgrades. This includes:*

- **Salary support to Indigenous Bands to hire community members who will visit homes in the community to review energy upgrade opportunities and install basic energy saving products.**
- **Training for these community members on how to review energy upgrade opportunities and install basic energy saving measures in homes.**
- **Training to Indigenous Bands that are planning to lead their own home renovation work and participate in our residential rebates. This training will be based on the Best Practice Guide: Air Sealing and Insulation Retrofits for Single Family Homes (2018 Second Edition).**
- **Other support as necessary to encourage energy upgrades and conservation behaviours in the community (e.g., presentations at community meetings, Elder and youth engagement, engagement with facility managers, etc.).**

2.46.3 Confirm, or explain otherwise, that the Net Levelized Cost and Benefit-Cost Ratio for the integrated system programs in Table 10-5 refers to DSM residential sector programs in the integrated system.

2.46.3.1 If not, re-calculate Table 10-5 using only DSM residential sector programs in the integrated system for F2020 – F2022 and the test period (F2020 – F2021).

RESPONSE:

The table below revises the comparison shown in Table 10-5, based on fiscal 2020 to fiscal 2022 results using residential integrated system programs as a comparison.

Table 10-5: Cost Effectiveness Comparison of Non-Integrated Areas and Residential Integrated System Programs

	Net Levelized Cost (non-integrated areas) ($/MWh)	Benefit-Cost Ratio (non-integrated areas)	Net Levelized Cost (integrated system residential programs) ($/MWh)	Benefit-Cost Ratio (integrated system residential programs)
Utility Cost	175	1.8	9	1.6
Total Resource Cost	159	1.9	10	2.6

The table below revises the comparison provided in Table 10-5, based on fiscal 2020 to fiscal 2021 results, using residential integrated system programs as a comparison.

Table 10-5: Cost Effectiveness Comparison of Non-Integrated Areas and Residential Integrated System Programs

	Net Levelized Cost (non-integrated areas) ($/MWh)	Benefit-Cost Ratio (non-integrated areas)	Net Levelized Cost (integrated system residential programs) ($/MWh)	Benefit-Cost Ratio (integrated system residential programs)
Utility Cost	180	1.8	9	1.6
Total Resource Cost	163	1.9	9	2.6

46.0 Topic: Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Chapter 10, Table 10-5, Appendix X, Appendix A, Table A-8; Exhibit B-5, BCUC IR 1.185.2, Exhibit B-6, Zone II RPG IR 1.21.1, IR 1.26.8

On page 1-12 of Chapter 10 of its F2020 – F2021 Application, BC Hydro provides the following table and Table A-8 on page 8 of 8 in Appendix A of Appendix X of the Application:

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

BC Hydro's response to BCUC IR 1.185.2 provides the following correction:

In preparing its response to this IR, BC Hydro discovered an error in its calculation of the Total Resource Cost (TRC) test for the Non-Integrated Areas program for the fiscal 2020 to fiscal 2022 period. The benefit-cost ratios in Table 10-5 of Chapter 10 of the Application are corrected in the table below.

	Net Levelized Cost (non-integrated areas) ($/MWh)	Benefit-Cost Ratio (non-integrated areas)
Total Resource Cost	**159**	**1.9**

In its response to Zone II RPG 1.21.1, BC Hydro clarifies that:

The cost effectiveness comparison information in Table 10-5 of Chapter 10 of the Application is for fiscal 2020 to fiscal 2022.

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**

In its response to Zone II RPG IR 1.26.8, BC Hydro provides details on the Community Support to *provide financial and technical resources to support them in pursuing energy upgrades. This includes:*

- **Salary support to Indigenous Bands to hire community members who will visit homes in the community to review energy upgrade opportunities and install basic energy saving products.**
- **Training for these community members on how to review energy upgrade opportunities and install basic energy saving measures in homes.**
- **Training to Indigenous Bands that are planning to lead their own home renovation work and participate in our residential rebates. This training will be based on the Best Practice Guide: Air Sealing and Insulation Retrofits for Single Family Homes (2018 Second Edition).**
- **Other support as necessary to encourage energy upgrades and conservation behaviours in the community (e.g., presentations at community meetings, Elder and youth engagement, engagement with facility managers, etc.).**

2.46.4 Using the data in Table A-8, show how the Utility Cost and Total Resource Cost in Table 10-5 are calculated for the integrated system and non-integrated areas programs.

RESPONSE:

This answer also responds to ZONE II RPG IR 2.46.6.

Attachment 1 to the response to CEABC IR 1.16.2 is a working Excel spreadsheet that shows the derivation of the values in Tables A-7, 10-5 (Benefit/Cost Ratios) and A-8 (Levelized Costs) of the Application. The present value of the associated variables used to derive Tables A-7 and A-8 can be seen in the "SUMMARY DATA" worksheet of the Excel file. Please note that in the SUMMARY DATA worksheet the Non-Integrated Area Program values are calculated in their own row (row 14), which in turn contribute to residential sector, program and portfolio totals which also include integrated system initiatives. To see a purely integrated system view at the residential sector, total programs and portfolio level (i.e., excluding the non-integrated areas program), please enter zeros in all variables (columns B to Q) for the "Non-Integrated Areas" line item (row 14) of the SUMMARY DATA worksheet to Attachment 1 of our response to CEABC IR 1.16.2.

The formula for Net Levelized Cost, which is the same for both integrated system programs and the Non-Integrated Areas Program, using data from Table A-8 is as follows (note all values are in units of $/MWh):

Net Levelized Costs = Gross Levelized Costs + Non-Electricity Benefits + Natural Gas Benefits + Capacity Benefits (Generation) + Capacity Benefits (Transmission and Distribution)

The Benefit-Cost Ratios for the Utility Cost and Total Resource Cost in Table 10-5 are calculated via the sum of present value benefits (in dollars), divided by the sum of present value costs (in dollars), drawing on the associated variables from the SUMMARY DATA worksheet. The formulas, which are the same for both the integrated system programs and the Non-Integrated Areas Program, are as follows:

Utility Cost:

Benefits = Energy Benefits (Market) + Capacity Benefits (T&D) + Capacity Benefits (Gen) + Utility NEBs

Costs = Utility Non-Incentive Costs + Utility Incentives

Total Resource Cost (Modified):

Benefits = Energy Benefits (LRMC) + Capacity Benefits (T&D) + Capacity Benefits (Gen) + Customer NEBs + Gas Benefits (Modified)

Costs = Utility Non-Incentive Costs + Customer Costs + Partner Costs

46.0 Topic: Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Chapter 10, Table 10-5, Appendix X, Appendix A, Table A-8; Exhibit B-5, BCUC IR 1.185.2, Exhibit B-6, Zone II RPG IR 1.21.1, IR 1.26.8

On page 1-12 of Chapter 10 of its F2020 – F2021 Application, BC Hydro provides the following table and Table A-8 on page 8 of 8 in Appendix A of Appendix X of the Application:

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

BC Hydro's response to BCUC IR 1.185.2 provides the following correction:

In preparing its response to this IR, BC Hydro discovered an error in its calculation of the Total Resource Cost (TRC) test for the Non-Integrated Areas program for the fiscal 2020 to fiscal 2022 period. The benefit-cost ratios in Table 10-5 of Chapter 10 of the Application are corrected in the table below.

	Net Levelized Cost (non-integrated areas) ($/MWh)	Benefit-Cost Ratio (non-integrated areas)
Total Resource Cost	159	1.9

In its response to Zone II RPG 1.21.1, BC Hydro clarifies that:

The cost effectiveness comparison information in Table 10-5 of Chapter 10 of the Application is for fiscal 2020 to fiscal 2022.

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	**$40**	**$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**

In its response to Zone II RPG IR 1.26.8, BC Hydro provides details on the Community Support to *provide financial and technical resources to support them in pursuing energy upgrades. This includes:*

- **Salary support to Indigenous Bands to hire community members who will visit homes in the community to review energy upgrade opportunities and install basic energy saving products.**
- **Training for these community members on how to review energy upgrade opportunities and install basic energy saving measures in homes.**
- **Training to Indigenous Bands that are planning to lead their own home renovation work and participate in our residential rebates. This training will be based on the Best Practice Guide: Air Sealing and Insulation Retrofits for Single Family Homes (2018 Second Edition).**
- **Other support as necessary to encourage energy upgrades and conservation behaviours in the community (e.g., presentations at community meetings, Elder and youth engagement, engagement with facility managers, etc.).**

2.46.5 In Table A-8, the Total Programs (integrated and non-integrated DSM Programs) Net Levelized Costs are -$11/MWh and $12/MWh for Total Resource Cost Test and Utility Cost Test, accordingly. Confirm, or explain otherwise, that the Net Levelized Cost and Benefit-Cost Ratio for the integrated system programs in Table 10-5 remove the Non-Integrated DSM costs. If not, recalculate the values in Table 10-5.

RESPONSE:

Confirmed.

46.0 Topic: Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Chapter 10, Table 10-5, Appendix X, Appendix A, Table A-8; Exhibit B-5, BCUC IR 1.185.2, Exhibit B-6, Zone II RPG IR 1.21.1, IR 1.26.8

On page 1-12 of Chapter 10 of its F2020 – F2021 Application, BC Hydro provides the following table and Table A-8 on page 8 of 8 in Appendix A of Appendix X of the Application:

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

BC Hydro's response to BCUC IR 1.185.2 provides the following correction:

In preparing its response to this IR, BC Hydro discovered an error in its calculation of the Total Resource Cost (TRC) test for the Non-Integrated Areas program for the fiscal 2020 to fiscal 2022 period. The benefit-cost ratios in Table 10-5 of Chapter 10 of the Application are corrected in the table below.

	Net Levelized Cost (non-integrated areas) ($/MWh)	Benefit-Cost Ratio (non-integrated areas)
Total Resource Cost	**159**	**1.9**

In its response to Zone II RPG 1.21.1, BC Hydro clarifies that:

The cost effectiveness comparison information in Table 10-5 of Chapter 10 of the Application is for fiscal 2020 to fiscal 2022.

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	**$40**	**$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**

In its response to Zone II RPG IR 1.26.8, BC Hydro provides details on the Community Support to *provide financial and technical resources to support them in pursuing energy upgrades. This includes:*

- **Salary support to Indigenous Bands to hire community members who will visit homes in the community to review energy upgrade opportunities and install basic energy saving products.**
- **Training for these community members on how to review energy upgrade opportunities and install basic energy saving measures in homes.**
- **Training to Indigenous Bands that are planning to lead their own home renovation work and participate in our residential rebates. This training will be based on the Best Practice Guide: Air Sealing and Insulation Retrofits for Single Family Homes (2018 Second Edition).**
- **Other support as necessary to encourage energy upgrades and conservation behaviours in the community (e.g., presentations at community meetings, Elder and youth engagement, engagement with facility managers, etc.).**

2.46.6 Using the data in Table A-8, show how the Benefit-Cost Ratios for Utility Cost and Total Resource Cost in Table 10-5 are calculated for the integrated and non-integrated system programs.

RESPONSE:

Please refer to BC Hydro's response to ZONE II RPG IR 2.46.4 for an explanation of how the Benefit-Cost Ratios for the Utility Cost and the Total Resource Cost in Table 10-5 are calculated for the integrated system programs and the Non-Integrated Area Program.

46.0 Topic: Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Chapter 10, Table 10-5, Appendix X, Appendix A, Table A-8; Exhibit B-5, BCUC IR 1.185.2, Exhibit B-6, Zone II RPG IR 1.21.1, IR 1.26.8

On page 1-12 of Chapter 10 of its F2020 – F2021 Application, BC Hydro provides the following table and Table A-8 on page 8 of 8 in Appendix A of Appendix X of the Application:

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

BC Hydro's response to BCUC IR 1.185.2 provides the following correction:

In preparing its response to this IR, BC Hydro discovered an error in its calculation of the Total Resource Cost (TRC) test for the Non-Integrated Areas program for the fiscal 2020 to fiscal 2022 period. The benefit-cost ratios in Table 10-5 of Chapter 10 of the Application are corrected in the table below.

	Net Levelized Cost (non-integrated areas) ($/MWh)	Benefit-Cost Ratio (non-integrated areas)
Total Resource Cost	159	1.9

In its response to Zone II RPG 1.21.1, BC Hydro clarifies that:

The cost effectiveness comparison information in Table 10-5 of Chapter 10 of the Application is for fiscal 2020 to fiscal 2022.

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	**$40**	**$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**

In its response to Zone II RPG IR 1.26.8, BC Hydro provides details on the Community Support to *provide financial and technical resources to support them in pursuing energy upgrades. This includes:*

- **Salary support to Indigenous Bands to hire community members who will visit homes in the community to review energy upgrade opportunities and install basic energy saving products.**
- **Training for these community members on how to review energy upgrade opportunities and install basic energy saving measures in homes.**
- **Training to Indigenous Bands that are planning to lead their own home renovation work and participate in our residential rebates. This training will be based on the Best Practice Guide: Air Sealing and Insulation Retrofits for Single Family Homes (2018 Second Edition).**
- **Other support as necessary to encourage energy upgrades and conservation behaviours in the community (e.g., presentations at community meetings, Elder and youth engagement, engagement with facility managers, etc.).**

2.46.7 Provide an explanation for each benefit category (non-electricity, natural gas, generation capacity and transmission and distribution capacity) listed in Table A-8 and how they are calculated for the integrated and non-integrated areas for DSM programs.

RESPONSE:

Explanations for each benefit category are provided below, along with how they are currently modelled for the integrated system and the Non-Integrated Areas (NIA).

Non-electricity benefits are benefits (or costs) that result from implementing the DSM initiative but are not directly captured by the reduction in electricity usage. These could include changes in maintenance costs, changes to equipment life, and changes to equipment productivity. Non-electricity benefits for integrated system programs differ based on the specific end use technologies targeted by the program. The Low Income Program is unique in that non-electricity benefits of 40 per cent are prescribed by the Demand-Side Measures Regulation. For the NIA Program, the non-electricity benefits modelled within the program relate to carbon tax savings resulting from the reduction in diesel fuel consumption. However, in responding to this IR, we discovered a double-counting of this benefit, which was already embedded within the avoided cost of diesel fuel used to value the energy savings. The carbon tax benefit represents about 5 per cent of the diesel fuel cost. Removing the benefit as a non-electricity benefit would result in a negligible impact on the cost-effectiveness of the NIA Program.

Natural gas benefits (or costs) are impacts on customers' natural gas consumption as a result of implementing the DSM initiative. For example, installing efficient insulation in an electrically heated home may also reduce gas consumption if that household has secondary heating equipment that uses gas (e.g., a fireplace). Natural gas benefits are included within integrated system programs depending on the specific end use level technologies targeted by the program. BC Hydro has not assumed any natural gas benefits in the NIA Program.

Capacity benefits are based on the deferral values for marginal generation resources (e.g., Revelstoke 6) for the integrated system and growth-related transmission and distribution infrastructure. For the NIA, the focus of DSM activities is to displace the need of fuel for incremental diesel generation, as the growth-related infrastructure investments are not significant. Infrastructure investments in the NIA are mostly to sustain existing assets. As such, for the purpose of DSM cost-effectiveness, generation and transmission and distribution capacity benefits for the NIA are assumed to be zero. However, there may be localized growth-related opportunities in some NIA communities where DSM may be part of the solution.

With respect to non-electricity benefits, BC Hydro recognizes that there are likely other non-electricity benefits that apply to the NIA, which have not yet been included in our modelling given the early stages of the NIA Program. For example, the 40 per cent adder for Low Income programs may apply to some components of the program. Likewise, there may be benefits associated with reducing consumption of secondary heating fuels (propane, oil, wood), similar to the natural gas benefits modelled for integrated system programs. BC Hydro expects to gather more information about some of these benefits. While the program is cost-effective without them, going forward BC Hydro will look to incorporate these types of benefits into the program model, as appropriate.

46.0 Topic: Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Chapter 10, Table 10-5, Appendix X, Appendix A, Table A-8; Exhibit B-5, BCUC IR 1.185.2, Exhibit B-6, Zone II RPG IR 1.21.1, IR 1.26.8

On page 1-12 of Chapter 10 of its F2020 – F2021 Application, BC Hydro provides the following table and Table A-8 on page 8 of 8 in Appendix A of Appendix X of the Application:

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

BC Hydro's response to BCUC IR 1.185.2 provides the following correction:

In preparing its response to this IR, BC Hydro discovered an error in its calculation of the Total Resource Cost (TRC) test for the Non-Integrated Areas program for the fiscal 2020 to fiscal 2022 period. The benefit-cost ratios in Table 10-5 of Chapter 10 of the Application are corrected in the table below.

	Net Levelized Cost (non-integrated areas) ($/MWh)	Benefit-Cost Ratio (non-integrated areas)
Total Resource Cost	**159**	**1.9**

In its response to Zone II RPG 1.21.1, BC Hydro clarifies that:

The cost effectiveness comparison information in Table 10-5 of Chapter 10 of the Application is for fiscal 2020 to fiscal 2022.

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**

In its response to Zone II RPG IR 1.26.8, BC Hydro provides details on the Community Support to *provide financial and technical resources to support them in pursuing energy upgrades*. *This includes:*

- **Salary support to Indigenous Bands to hire community members who will visit homes in the community to review energy upgrade opportunities and install basic energy saving products.**
- **Training for these community members on how to review energy upgrade opportunities and install basic energy saving measures in homes.**
- **Training to Indigenous Bands that are planning to lead their own home renovation work and participate in our residential rebates. This training will be based on the Best Practice Guide: Air Sealing and Insulation Retrofits for Single Family Homes (2018 Second Edition).**
- **Other support as necessary to encourage energy upgrades and conservation behaviours in the community (e.g., presentations at community meetings, Elder and youth engagement, engagement with facility managers, etc.).**

2.46.8 Explain the reasons why the Utility Cost for NIA is greater than the integrated system?

RESPONSE:

This answer also responds to ZONE II RPG IR 2.46.9.

In reference to the updated Table 10-5 in the response to ZONE II IR 2.46.3.1, the Net Levelized Utility Cost and the Total Resource Cost for NIA are greater than the integrated system Residential sector programs for several reasons, including:

- **The composition of the NIA program relies more heavily on higher cost measures related to weatherization and heat pumps, with a much smaller contribution from lower cost measures such as lighting;**
- **The incentive offer for NIA weatherization measures is higher than the integrated system which impacts the Net Levelized Utility Cost;**
- **Higher non-incentive costs are required for NIA to overcome market and logistical barriers, and there are less economies of scale in operating the NIA program compared to similar integrated system programs; and**
- **There are no capacity benefits related to the NIA program, which has the effect of making the NIA program's Net Levelized Utility Cost and Total Resource Cost more expensive relative to programs in the integrated system.**

46.0 Topic: Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Chapter 10, Table 10-5, Appendix X, Appendix A, Table A-8; Exhibit B-5, BCUC IR 1.185.2, Exhibit B-6, Zone II RPG IR 1.21.1, IR 1.26.8

On page 1-12 of Chapter 10 of its F2020 – F2021 Application, BC Hydro provides the following table and Table A-8 on page 8 of 8 in Appendix A of Appendix X of the Application:

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

BC Hydro's response to BCUC IR 1.185.2 provides the following correction:

In preparing its response to this IR, BC Hydro discovered an error in its calculation of the Total Resource Cost (TRC) test for the Non-Integrated Areas program for the fiscal 2020 to fiscal 2022 period. The benefit-cost ratios in Table 10-5 of Chapter 10 of the Application are corrected in the table below.

	Net Levelized Cost (non-integrated areas) ($/MWh)	Benefit-Cost Ratio (non-integrated areas)
Total Resource Cost	159	1.9

In its response to Zone II RPG 1.21.1, BC Hydro clarifies that:

The cost effectiveness comparison information in Table 10-5 of Chapter 10 of the Application is for fiscal 2020 to fiscal 2022.

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	-$8	$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	**$40**	**$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**

In its response to Zone II RPG IR 1.26.8, BC Hydro provides details on the Community Support to *provide financial and technical resources to support them in pursuing energy upgrades*. *This includes:*

- **Salary support to Indigenous Bands to hire community members who will visit homes in the community to review energy upgrade opportunities and install basic energy saving products.**
- **Training for these community members on how to review energy upgrade opportunities and install basic energy saving measures in homes.**
- **Training to Indigenous Bands that are planning to lead their own home renovation work and participate in our residential rebates. This training will be based on the Best Practice Guide: Air Sealing and Insulation Retrofits for Single Family Homes (2018 Second Edition).**
- **Other support as necessary to encourage energy upgrades and conservation behaviours in the community (e.g., presentations at community meetings, Elder and youth engagement, engagement with facility managers, etc.).**

2.46.8 Explain the reasons why the Utility Cost for NIA is greater than the integrated system?

2.46.8.1 Confirm, or explain otherwise, whether BC Hydro would expect the Utility Cost for NIA to decline over the years after start-up, training, support/education and program delivery, etc. are established.

RESPONSE:

We do not anticipate the Non-Integrated Area (NIA) program Net Levelized Utility Cost and Total Resource Cost declining after start up. This is because the non-incentive costs are forecast to stay relatively constant as explained in our response to ZONE II RPG IR 2.47.5.1, and because our plans assume a similar mix of measures and incentives going forward.

46.0 Topic: Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Chapter 10, Table 10-5, Appendix X, Appendix A, Table A-8; Exhibit B-5, BCUC IR 1.185.2, Exhibit B-6, Zone II RPG IR 1.21.1, IR 1.26.8

On page 1-12 of Chapter 10 of its F2020 – F2021 Application, BC Hydro provides the following table and Table A-8 on page 8 of 8 in Appendix A of Appendix X of the Application:

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	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

BC Hydro's response to BCUC IR 1.185.2 provides the following correction:

In preparing its response to this IR, BC Hydro discovered an error in its calculation of the Total Resource Cost (TRC) test for the Non-Integrated Areas program for the fiscal 2020 to fiscal 2022 period. The benefit-cost ratios in Table 10-5 of Chapter 10 of the Application are corrected in the table below.

	Net Levelized Cost (non-integrated areas) ($/MWh)	Benefit-Cost Ratio (non-integrated areas)
Total Resource Cost	**159**	**1.9**

In its response to Zone II RPG 1.21.1, BC Hydro clarifies that:

The cost effectiveness comparison information in Table 10-5 of Chapter 10 of the Application is for fiscal 2020 to fiscal 2022.

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
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Commercial Sector												
LEM-C	$51	$19	-$72	$0	-$3	$0	-$12	-$12	-$2	-$2	-$39	$4
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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	**$40**	**$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**

In its response to Zone II RPG IR 1.26.8, BC Hydro provides details on the Community Support to *provide financial and technical resources to support them in pursuing energy upgrades*. *This includes:*

- **Salary support to Indigenous Bands to hire community members who will visit homes in the community to review energy upgrade opportunities and install basic energy saving products.**
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- **Other support as necessary to encourage energy upgrades and conservation behaviours in the community (e.g., presentations at community meetings, Elder and youth engagement, engagement with facility managers, etc.).**

2.46.9 Explain the reasons why is the Total Resource Cost for NIA is greater than the integrated system?

RESPONSE:

The reasons outlined in BC Hydro’s response to ZONE II RPG IR 2.46.8 also explain why the Total Resource Cost for NIA is greater than the integrated system.

46.0 Topic: Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Chapter 10, Table 10-5, Appendix X, Appendix A, Table A-8; Exhibit B-5, BCUC IR 1.185.2, Exhibit B-6, Zone II RPG IR 1.21.1, IR 1.26.8

On page 1-12 of Chapter 10 of its F2020 – F2021 Application, BC Hydro provides the following table and Table A-8 on page 8 of 8 in Appendix A of Appendix X of the Application:

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

BC Hydro's response to BCUC IR 1.185.2 provides the following correction:

In preparing its response to this IR, BC Hydro discovered an error in its calculation of the Total Resource Cost (TRC) test for the Non-Integrated Areas program for the fiscal 2020 to fiscal 2022 period. The benefit-cost ratios in Table 10-5 of Chapter 10 of the Application are corrected in the table below.

	Net Levelized Cost (non-integrated areas) ($/MWh)	Benefit-Cost Ratio (non-integrated areas)
Total Resource Cost	**159**	**1.9**

In its response to Zone II RPG 1.21.1, BC Hydro clarifies that:

The cost effectiveness comparison information in Table 10-5 of Chapter 10 of the Application is for fiscal 2020 to fiscal 2022.

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	**$40**	**$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**

In its response to Zone II RPG IR 1.26.8, BC Hydro provides details on the Community Support to *provide financial and technical resources to support them in pursuing energy upgrades*. *This includes:*

- **Salary support to Indigenous Bands to hire community members who will visit homes in the community to review energy upgrade opportunities and install basic energy saving products.**
- **Training for these community members on how to review energy upgrade opportunities and install basic energy saving measures in homes.**
- **Training to Indigenous Bands that are planning to lead their own home renovation work and participate in our residential rebates. This training will be based on the Best Practice Guide: Air Sealing and Insulation Retrofits for Single Family Homes (2018 Second Edition).**
- **Other support as necessary to encourage energy upgrades and conservation behaviours in the community (e.g., presentations at community meetings, Elder and youth engagement, engagement with facility managers, etc.).**

2.46.9 Explain the reasons why is the Total Resource Cost for NIA is greater than the integrated system?

2.46.9.1 Confirm, or explain otherwise, whether BC Hydro would expect the Total Resource Cost for NIA to decline over the years after start-up, training and program delivery, etc. are established.

RESPONSE:

Not confirmed. Please refer to BC Hydro's response to ZONE II RPG IR 2.46.8.1 for a discussion of cost expectations for the Non-Integrated Areas program.

47.0 Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Appendix X Table A-1; Exhibit B-6, Zone II RPG IR 1.21.1.1

In its response to Zone II RPG IR 1.21.1.1, BC Hydro provide the following table for the previous fiscal years 2013 - 2017:

	Expenditures	New Incremental Electricity Savings	Benefit Cost Ratios				Net Levelized
	Actual $	Actual kWh/yr	Utility Test	Total Resource Cost Test	Total Resource Cost Test as modified by DSM Regulation	Ratepayer Impact Measure Test	Utility Cost ($/MWh)
DSM Program Activity	$349,837	1,724,288	7.2	2.6	3.0	1.6	45
Pilot Project Initiatives	$280,414	n/a	n/a	n/a	n/a	n/a	n/a

Note 1: **Includes all DSM program incentives and pilot project expenditures tracked separately as well as an allocation of Low Income Program incentives.**

Note 2: **Includes all new incremental electricity savings for DSM programs tracked separately.**

Note 3: **Long Run Marginal Cost (LRMC) is based on generation costs in the Non-Integrated Areas.**

Note 4: **Not all components required to calculate cost effectiveness are tracked separately. Therefore, assumptions were developed for utility costs and customer cost in order to calculate cost effectiveness.**

Note 5: **For the low income components included within DSM Non-Integrated Area 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.**

……..

The new standalone NIA program offers a wider breadth of measures, many of them with higher costs than those reflected in fiscal 2018, which lowers the cost-effectiveness.

In addition the Non-Integrated Areas program carries with it all of the non-incentive costs associated with administering, marketing and delivering a standalone program, which contributes to the lower UC benefit-cost ratio.

From Appendix X of its F2020 – F2021 Application, BC Hydro provides the following tables:

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-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**

2.47.1 In the past, how did BC Hydro determine the spending budget on DSM Program Activities and Pilot Project Initiatives in the NIA?

RESPONSE:

BC Hydro's DSM programs are designed and managed as province-wide initiatives, with expenditures forecast for our entire service territory, rather than by any subset (e.g., Integrated versus Non-Integrated Area). No specific budget was established for Non-Integrated Area participants within these DSM program activities. The expenditures for DSM program activities shown in BC Hydro's response to ZONE II RPG IR 1.21.1.1 reflect the expenditures that related to Non-Integrated Area participants.

For pilot project initiatives, we determined the pilot activities needed to better understand and address barriers to DSM for customers. We then estimated how many participants would be involved in these pilot activities and set a budget based on our estimate of what it would require to deliver the pilot activities to the participants.

47.0 Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Appendix X Table A-1; Exhibit B-6, Zone II RPG IR 1.21.1.1

In its response to Zone II RPG IR 1.21.1.1, BC Hydro provide the following table for the previous fiscal years 2013 - 2017:

	Expenditures	New Incremental Electricity Savings	Benefit Cost Ratios				Net Levelized
	Actual $	Actual kWh/yr	Utility Test	Total Resource Cost Test	Total Resource Cost Test as modified by DSM Regulation	Ratepayer Impact Measure Test	Utility Cost ($/MWh)
DSM Program Activity	$349,837	1,724,288	7.2	2.6	3.0	1.6	45
Pilot Project Initiatives	$280,414	n/a	n/a	n/a	n/a	n/a	n/a

Note 1: **Includes all DSM program incentives and pilot project expenditures tracked separately as well as an allocation of Low Income Program incentives.**

Note 2: **Includes all new incremental electricity savings for DSM programs tracked separately.**

Note 3: **Long Run Marginal Cost (LRMC) is based on generation costs in the Non-Integrated Areas.**

Note 4: **Not all components required to calculate cost effectiveness are tracked separately. Therefore, assumptions were developed for utility costs and customer cost in order to calculate cost effectiveness.**

Note 5: **For the low income components included within DSM Non-Integrated Area 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.**

……..

The new standalone NIA program offers a wider breadth of measures, many of them with higher costs than those reflected in fiscal 2018, which lowers the cost-effectiveness.

In addition the Non-Integrated Areas program carries with it all of the non-incentive costs associated with administering, marketing and delivering a standalone program, which contributes to the lower UC benefit-cost ratio.

From Appendix X of its F2020 – F2021 Application, BC Hydro provides the following tables:

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-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*
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Supporting Initiatives				
Public Awareness	7.4	7.5	7.6	22.5
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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**

2.47.2 What LRMC did BC Hydro use according to Note 3 and how was this determined?

RESPONSE:

As discussed in BC Hydro's response to BCUC IR 1.185.1, a value of $300/MWh (Fiscal 2015$) was used as the long-run marginal cost of avoided energy for NIA DSM cost-effectiveness purposes. This is a high level proxy for the diesel generation fuel cost across the NIA.

47.0 Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Appendix X Table A-1; Exhibit B-6, Zone II RPG IR 1.21.1.1

In its response to Zone II RPG IR 1.21.1.1, BC Hydro provide the following table for the previous fiscal years 2013 - 2017:

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Pilot Project Initiatives	$280,414	n/a	n/a	n/a	n/a	n/a	n/a

Note 1: **Includes all DSM program incentives and pilot project expenditures tracked separately as well as an allocation of Low Income Program incentives.**

Note 2: **Includes all new incremental electricity savings for DSM programs tracked separately.**

Note 3: **Long Run Marginal Cost (LRMC) is based on generation costs in the Non-Integrated Areas.**

Note 4: **Not all components required to calculate cost effectiveness are tracked separately. Therefore, assumptions were developed for utility costs and customer cost in order to calculate cost effectiveness.**

Note 5: **For the low income components included within DSM Non-Integrated Area 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.**

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The new standalone NIA program offers a wider breadth of measures, many of them with higher costs than those reflected in fiscal 2018, which lowers the cost-effectiveness.

In addition the Non-Integrated Areas program carries with it all of the non-incentive costs associated with administering, marketing and delivering a standalone program, which contributes to the lower UC benefit-cost ratio.

From Appendix X of its F2020 – F2021 Application, BC Hydro provides the following tables:

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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-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**

2.47.3 Per Note 4, please describe the assumptions developed in order to calculate cost effectiveness.

RESPONSE:

In BC Hydro's response to ZONE II RPG IR 1.21.1.1 we stated that not all components required to calculate cost effectiveness are tracked separately, and therefore assumptions were developed for utility costs and customer costs in order to calculate cost effectiveness. This was the case for three components of the cost-effectiveness calculation for the DSM Program Activity row where the program activity occurred in the Non-Integrated Areas through participation in the province-wide DSM programs.

Non-Incentive Costs

Non-incentive costs were derived based on the Non-Integrated Area savings as a percentage of the associated province-wide program's total energy savings multiplied by the associated province-wide program's total non-incentive cost. For example, if the Non-Integrated Area savings from the Home Renovation Rebate program participation were 1 GWh/year and the total Home Renovation Rebate program savings were 20 GWh/year, then the Non-Integrated Area would have 5 per cent of the total savings, and accordingly, 5 per cent of the total Home Renovation Rebate program non-incentive costs would be assumed for Non-Integrated Area.

Non-incentive costs for the participants in the Non-Integrated Areas were based on the non-incentive costs for the integrated areas. In addition, a scalar was applied for some programs to reflect the higher cost to deliver the program in the Non-Integrated Areas.

Incentive Costs

Incentive costs were based on the incentives for the integrated areas. In addition, a scalar was applied for some programs to reflect higher costs to implement a project in the Non-Integrated Areas. For example, programs with a direct install component would have higher cost in the Non-Integrated Areas.

Customer Costs

Customer costs used were based on customer costs for the integrated areas. In addition, a scalar was applied for some programs to reflect the higher cost of implementing projects in the Non-Integrated Areas. In these situations the scalar was the same as that used for the incentive costs.

47.0 Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Appendix X Table A-1; Exhibit B-6, Zone II RPG IR 1.21.1.1

In its response to Zone II RPG IR 1.21.1.1, BC Hydro provide the following table for the previous fiscal years 2013 - 2017:

	Expenditures	New Incremental Electricity Savings	Benefit Cost Ratios				Net Levelized
	Actual $	Actual kWh/yr	Utility Test	Total Resource Cost Test	Total Resource Cost Test as modified by DSM Regulation	Ratepayer Impact Measure Test	Utility Cost ($/MWh)
DSM Program Activity	$349,837	1,724,288	7.2	2.6	3.0	1.6	45
Pilot Project Initiatives	$280,414	n/a	n/a	n/a	n/a	n/a	n/a

Note 1: **Includes all DSM program incentives and pilot project expenditures tracked separately as well as an allocation of Low Income Program incentives.**

Note 2: **Includes all new incremental electricity savings for DSM programs tracked separately.**

Note 3: **Long Run Marginal Cost (LRMC) is based on generation costs in the Non-Integrated Areas.**

Note 4: **Not all components required to calculate cost effectiveness are tracked separately. Therefore, assumptions were developed for utility costs and customer cost in order to calculate cost effectiveness.**

Note 5: **For the low income components included within DSM Non-Integrated Area 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.**

……..

The new standalone NIA program offers a wider breadth of measures, many of them with higher costs than those reflected in fiscal 2018, which lowers the cost-effectiveness.

In addition the Non-Integrated Areas program carries with it all of the non-incentive costs associated with administering, marketing and delivering a standalone program, which contributes to the lower UC benefit-cost ratio.

From Appendix X of its F2020 – F2021 Application, BC Hydro provides the following tables:

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-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**

2.47.4 Compared to fiscal 2018, list the new measures being added as part of the new Non-Integrated Areas program.

RESPONSE:

This answer also responds to ZONE II RPG IR 2.47.4.1.

In fiscal 2018, residential customers in the Non-Integrated Areas (NIA) had access to incentives for home energy upgrades through existing residential programs (Low Income Program and the Home Renovation Rebate Program). Starting in fiscal 2020, BC Hydro is offering a dedicated program for NIA customers. The table below outlines the new and enhanced measures and incentives through the new program that are available to residential customers and Indigenous Bands in the NIA during the test period and compares them to offers in fiscal 2018 that were available through the existing residential programs.

Measures	Offer in fiscal 2018	Offer in test period
Free basic energy savings measures for residential households		
Energy Savings Kit (ESK)	Free to income-qualified households	Free to all homes
Free basic energy savings measures for Indigenous Bands, including:		
LED light bulbs	15 light bulbs	25 light bulbs per home
LED specialty bulbs	Not offered	
Caulking	Not offered	Offered
Window film	Offered every 5 years via ESK	Offered annually
Dryer rack or clothesline	Not offered	Offered
Combination carbon monoxide / smoke detector	Not offered	Offered
Advanced power strips	Not offered	Offered
Rebates for home energy upgrades led by Indigenous Bands:		
Health and Safety Upgrades	Not offered	Up to $1,000 per home
Attic Insulation	$.02 x R-Value added x sq ft ($600 max)	$.05 x R-Value added x sq ft ($1,800 max)
Exterior Wall Insulation	$.08 x R-Value added x sq ft ($1,200 max)	$.20 x R-Value added x sq ft ($2,000 max)
Basement/Crawl Insulation	$.08 x R-Value added x sq ft ($1,000 max)	$.20 x R-Value added x sq ft ($2,000 max)
Insulation Other	$.05 x R-Value added x sq ft ($450 max)	$.125 x R-Value added x sq ft ($1,500 max)
Ventilation (fully ducted bathroom fan system)	Not offered	$1,200
Windows and doors (Tier 1)	Not offered	$100
Windows and doors (Tier 2)	$50	$200

Measures	Offer in fiscal 2018	Offer in test period
Ductless air source heat pump	**$800**	**$1,000**
Central air source heat pump	**Not offered**	**$2,000**
Heat pump water heater	**Not offered**	**$1,000**
Smart Thermostat	**Not offered**	**$100**
Refrigerator	**Offered via ECAP Basic to eligible homes**	**$1,000**
Chest freezer	**Not offered**	**$400**

Program offers to support commercial customers in the NIA are currently in development and will be launched in the third quarter of fiscal 2020.

47.0 Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Appendix X Table A-1; Exhibit B-6, Zone II RPG IR 1.21.1.1

In its response to Zone II RPG IR 1.21.1.1, BC Hydro provide the following table for the previous fiscal years 2013 - 2017:

	Expenditures	New Incremental Electricity Savings	Benefit Cost Ratios				Net Levelized
	Actual $	Actual kWh/yr	Utility Test	Total Resource Cost Test	Total Resource Cost Test as modified by DSM Regulation	Ratepayer Impact Measure Test	Utility Cost ($/MWh)
DSM Program Activity	$349,837	1,724,288	7.2	2.6	3.0	1.6	45
Pilot Project Initiatives	$280,414	n/a	n/a	n/a	n/a	n/a	n/a

Note 1: **Includes all DSM program incentives and pilot project expenditures tracked separately as well as an allocation of Low Income Program incentives.**

Note 2: **Includes all new incremental electricity savings for DSM programs tracked separately.**

Note 3: **Long Run Marginal Cost (LRMC) is based on generation costs in the Non-Integrated Areas.**

Note 4: **Not all components required to calculate cost effectiveness are tracked separately. Therefore, assumptions were developed for utility costs and customer cost in order to calculate cost effectiveness.**

Note 5: **For the low income components included within DSM Non-Integrated Area 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.**

……..

The new standalone NIA program offers a wider breadth of measures, many of them with higher costs than those reflected in fiscal 2018, which lowers the cost-effectiveness.

In addition the Non-Integrated Areas program carries with it all of the non-incentive costs associated with administering, marketing and delivering a standalone program, which contributes to the lower UC benefit-cost ratio.

From Appendix X of its F2020 – F2021 Application, BC Hydro provides the following tables:

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-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**

2.47.4 Compared to fiscal 2018, list the new measures being added as part of the new Non-Integrated Areas program.

2.47.4.1 Identify those measures which come with higher costs compared to those reflected in fiscal 2018?

RESPONSE:

Please refer to BC Hydro's response to ZONE II RPG IR 2.47.4.

47.0 Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Appendix X Table A-1; Exhibit B-6, Zone II RPG IR 1.21.1.1

In its response to Zone II RPG IR 1.21.1.1, BC Hydro provide the following table for the previous fiscal years 2013 - 2017:

	Expenditures	New Incremental Electricity Savings	Benefit Cost Ratios				Net Levelized
	Actual $	Actual kWh/yr	Utility Test	Total Resource Cost Test	Total Resource Cost Test as modified by DSM Regulation	Ratepayer Impact Measure Test	Utility Cost ($/MWh)
DSM Program Activity	$349,837	1,724,288	7.2	2.6	3.0	1.6	45
Pilot Project Initiatives	$280,414	n/a	n/a	n/a	n/a	n/a	n/a

Note 1: **Includes all DSM program incentives and pilot project expenditures tracked separately as well as an allocation of Low Income Program incentives.**

Note 2: **Includes all new incremental electricity savings for DSM programs tracked separately.**

Note 3: **Long Run Marginal Cost (LRMC) is based on generation costs in the Non-Integrated Areas.**

Note 4: **Not all components required to calculate cost effectiveness are tracked separately. Therefore, assumptions were developed for utility costs and customer cost in order to calculate cost effectiveness.**

Note 5: **For the low income components included within DSM Non-Integrated Area 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.**

……..

The new standalone NIA program offers a wider breadth of measures, many of them with higher costs than those reflected in fiscal 2018, which lowers the cost-effectiveness.

In addition the Non-Integrated Areas program carries with it all of the non-incentive costs associated with administering, marketing and delivering a standalone program, which contributes to the lower UC benefit-cost ratio.

From Appendix X of its F2020 – F2021 Application, BC Hydro provides the following tables:

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-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
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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**

2.47.4 Compared to fiscal 2018, list the new measures being added as part of the new Non-Integrated Areas program.

2.47.4.2 Explain rational for including the measures that it did in its new NIA DSM program.

RESPONSE:

Please refer to BC Hydro's response to ZONE II RPG IR 2.52.1, where we explain the rationale for including the measures in the NIA program.

47.0 Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Appendix X Table A-1; Exhibit B-6, Zone II RPG IR 1.21.1.1

In its response to Zone II RPG IR 1.21.1.1, BC Hydro provide the following table for the previous fiscal years 2013 - 2017:

	Expenditures	New Incremental Electricity Savings	Benefit Cost Ratios				Net Levelized
	Actual $	Actual kWh/yr	Utility Test	Total Resource Cost Test	Total Resource Cost Test as modified by DSM Regulation	Ratepayer Impact Measure Test	Utility Cost ($/MWh)
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Pilot Project Initiatives	$280,414	n/a	n/a	n/a	n/a	n/a	n/a

Note 1: **Includes all DSM program incentives and pilot project expenditures tracked separately as well as an allocation of Low Income Program incentives.**

Note 2: **Includes all new incremental electricity savings for DSM programs tracked separately.**

Note 3: **Long Run Marginal Cost (LRMC) is based on generation costs in the Non-Integrated Areas.**

Note 4: **Not all components required to calculate cost effectiveness are tracked separately. Therefore, assumptions were developed for utility costs and customer cost in order to calculate cost effectiveness.**

Note 5: **For the low income components included within DSM Non-Integrated Area 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.**

……..

The new standalone NIA program offers a wider breadth of measures, many of them with higher costs than those reflected in fiscal 2018, which lowers the cost-effectiveness.

In addition the Non-Integrated Areas program carries with it all of the non-incentive costs associated with administering, marketing and delivering a standalone program, which contributes to the lower UC benefit-cost ratio.

From Appendix X of its F2020 – F2021 Application, BC Hydro provides the following tables:

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-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**

2.47.5 Please confirm, or explain otherwise, that the highlighted Non-Incentive costs in Table A-3 are the costs of administering, marketing and delivering the standalone NIA DSM program.

RESPONSE:

The non-incentive costs for the Non-Integrated Areas Program in Table A-3 are comprised of a variety of activities, including:

- **Training and salary support for Indigenous Bands to hire community members who will visit homes in the community to review energy upgrade opportunities and install basic energy saving products;**
- **Training for Indigenous Bands (and their contractors) that are planning to lead their own home renovation work and participate in our residential rebates;**
- **Other support to encourage energy upgrades and conservation behaviours in the community (e.g. presentations at community meetings, elder and youth engagement, and engagement with facility managers); and**
- **Program management, program delivery, operations, marketing, advertising and evaluation.**

47.0 Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Appendix X Table A-1; Exhibit B-6, Zone II RPG IR 1.21.1.1

In its response to Zone II RPG IR 1.21.1.1, BC Hydro provide the following table for the previous fiscal years 2013 - 2017:

	Expenditures	New Incremental Electricity Savings	Benefit Cost Ratios				Net Levelized
	Actual $	Actual kWh/yr	Utility Test	Total Resource Cost Test	Total Resource Cost Test as modified by DSM Regulation	Ratepayer Impact Measure Test	Utility Cost ($/MWh)
DSM Program Activity	$349,837	1,724,288	7.2	2.6	3.0	1.6	45
Pilot Project Initiatives	$280,414	n/a	n/a	n/a	n/a	n/a	n/a

Note 1: **Includes all DSM program incentives and pilot project expenditures tracked separately as well as an allocation of Low Income Program incentives.**

Note 2: **Includes all new incremental electricity savings for DSM programs tracked separately.**

Note 3: **Long Run Marginal Cost (LRMC) is based on generation costs in the Non-Integrated Areas.**

Note 4: **Not all components required to calculate cost effectiveness are tracked separately. Therefore, assumptions were developed for utility costs and customer cost in order to calculate cost effectiveness.**

Note 5: **For the low income components included within DSM Non-Integrated Area 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.**

……..

The new standalone NIA program offers a wider breadth of measures, many of them with higher costs than those reflected in fiscal 2018, which lowers the cost-effectiveness.

In addition the Non-Integrated Areas program carries with it all of the non-incentive costs associated with administering, marketing and delivering a standalone program, which contributes to the lower UC benefit-cost ratio.

From Appendix X of its F2020 – F2021 Application, BC Hydro provides the following tables:

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-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**

2.47.5 Please confirm, or explain otherwise, that the highlighted Non-Incentive costs in Table A-3 are the costs of administering, marketing and delivering the standalone NIA DSM program.

2.47.5.1 Confirm, or explain otherwise, if BC Hydro expects these costs to decline in future years as the program becomes more established.

RESPONSE:

Not confirmed. BC Hydro has modelled non-incentive costs based on the current expectation that they will stay relatively constant over a ten year period. We may find some efficiencies in these costs as the program becomes more established in the market; however, we also anticipate that new training and support needs may arise as the program evolves to address barriers and opportunities in these communities over time.

47.0 Demand-Side Management – Cost Effectiveness Comparison

Reference: Exhibit B-1, Application, Appendix X Table A-1; Exhibit B-6, Zone II RPG IR 1.21.1.1

In its response to Zone II RPG IR 1.21.1.1, BC Hydro provide the following table for the previous fiscal years 2013 - 2017:

	Expenditures	New Incremental Electricity Savings	Benefit Cost Ratios				Net Levelized
	Actual $	Actual kWh/yr	Utility Test	Total Resource Cost Test	Total Resource Cost Test as modified by DSM Regulation	Ratepayer Impact Measure Test	Utility Cost ($/MWh)
DSM Program Activity	$349,837	1,724,288	7.2	2.6	3.0	1.6	45
Pilot Project Initiatives	$280,414	n/a	n/a	n/a	n/a	n/a	n/a

Note 1: **Includes all DSM program incentives and pilot project expenditures tracked separately as well as an allocation of Low Income Program incentives.**

Note 2: **Includes all new incremental electricity savings for DSM programs tracked separately.**

Note 3: **Long Run Marginal Cost (LRMC) is based on generation costs in the Non-Integrated Areas.**

Note 4: **Not all components required to calculate cost effectiveness are tracked separately. Therefore, assumptions were developed for utility costs and customer cost in order to calculate cost effectiveness.**

Note 5: **For the low income components included within DSM Non-Integrated Area 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.**

……..

The new standalone NIA program offers a wider breadth of measures, many of them with higher costs than those reflected in fiscal 2018, which lowers the cost-effectiveness.

In addition the Non-Integrated Areas program carries with it all of the non-incentive costs associated with administering, marketing and delivering a standalone program, which contributes to the lower UC benefit-cost ratio.

From Appendix X of its F2020 – F2021 Application, BC Hydro provides the following tables:

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-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**

2.47.5 Please confirm, or explain otherwise, that the highlighted Non-Incentive costs in Table A-3 are the costs of administering, marketing and delivering the standalone NIA DSM program.

2.47.5.2 On a % and gross amount basis ($), list the costs of administering, marketing and delivering programs for other DSM programs in Table A-1 that BC Hydro provides.

RESPONSE:

Non-incentive costs are provided in Table A-3 of Appendix A to Appendix X of the Application. Non-incentive costs include a range of items such as program management, program delivery, operations, marketing, advertising, evaluation and measurement and verification. The specific activities contained in non-incentive costs, and their magnitude depends in part on the specific barriers being addressed within a program. This results in a variation of activities across programs and in turn a variation of non-incentive costs related to those activities.

The non-incentive cost as a per cent of the total program cost is shown below.

	Forecast F2020 (%)	**Forecast F2021 (%)**	**Forecast F2022 (%)**
DSM Programs			
Residential Sector			
Low Income	36	31	27
Non Integrated Areas	54	47	47
Retail	69	68	67
Home Renovation Rebate	25	21	23
Residential Energy Management Activities	87	88	90
Residential Sector Total	*52*	*48*	*47*
Commercial Sector			
LEM-C	39	41	41
New Construction	22	29	27
Commercial Energy Management Activities	40	42	43
Commercial Sector Total	*36*	*40*	*40*
Industrial Sector			
LEM-I	22	22	22
Thermo-Mechanical Pulp[1]	n/a	n/a	n/a
Industrial Energy Management Activities	33	33	33
Industrial Sector Total	*25*	*25*	*26*
Total Programs	**36**	**36**	**36**

[1] **Thermo-Mechanical Pulp Program activities originally planned for fiscal 2021 have been removed from the forecast in this response, consistent with the Evidentiary Update.**

48.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan

Reference: Exhibit B-6, Zone II RPG IR 1.23.2, 1.23.4, 1.26.1.1, I.26.9.1

In its response to Zone II RPG IR 1.23.2 and 1.23.4, BC Hydro provided the following tables:

DSM activities in the last five years have reduced the bills for participating Non-Integrated Areas customers, as shown in the table below.

	Fiscal 2014 Actual	Fiscal 2015 Actual	Fiscal 2016 Actual	Fiscal 2017 Actual	Fiscal 2018 Actual
Cumulative Savings (GWh/year)	0.09	0.36	1.60	1.64	1.80
Bill Savings associated with Cumulative Savings ($ 000)	8	37	162	166	186

Forecast bill savings during the test period for customers participating in the new Non-Integrated Areas program are shown in the table below.

	Fiscal 2020 Plan	Fiscal 2021 Plan
New Incremental Savings (GWh/year)	0.45	0.61
Estimated Bill Savings ($ 000)	52	72

In its response to Zone II RPG IR 1.6.1.1, BC Hydro provided the following response:

BC Hydro is in the process of assessing the pilot work conducted between

fiscal 2017 and fiscal 2019 in the Non-Integrated Areas and expects to complete a report towards the end of fiscal 2020.

In its response to Zone II RPG IR 1.26.9.1, BC Hydro stated:

Ramping up participating levels and achieving expected savings will be a challenge. BC Hydro is addressing these challenges by:

- *Minimizing BC Hydro's program requirements, where possible. BC Hydro is in the process of hiring a new Relationship Lead to assist the communities and local contractors.*

- *Designing the program to enable Indigenous communities to lead implementation of the offer within their communities.*
- *Continuing to utilize communication channels in NIA communities that were established during pilot initiatives, increasing awareness of BC Hydro's energy conservation efforts with customers, Indigenous bands and trade allies.*
- *Using proven technologies and processes and implementing projects similar to those that BC Hydro has analyzed for savings potential in the past.*
- *Applying learnings from pilot initiatives with Indigenous and remote communities. For example, BC Hydro found that weatherization upgrades were at times limited by health and safety issues in the home such as mould/moisture, presence of pests, asbestos, radon, etc. To deal with this, we've incorporated a rebate for health and safety upgrades to enable additional weatherization upgrades and energy savings to occur.*

2.48.1 Explain the reasons for the significant increase in energy and bill savings in fiscal 2016 vs. fiscal 2015 for DSM activities in NIA?

RESPONSE:

The Non-Integrated Areas energy and bill savings increased in fiscal 2016 due to one project processed through the Home Renovation Rebate program that amalgamated a high volume of individual heat pumps.

48.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan

Reference: Exhibit B-6, Zone II RPG IR 1.23.2, 1.23.4, 1.26.1.1, I.26.9.1

In its response to Zone II RPG IR 1.23.2 and 1.23.4, BC Hydro provided the following tables:

DSM activities in the last five years have reduced the bills for participating Non-Integrated Areas customers, as shown in the table below.

	Fiscal 2014 Actual	Fiscal 2015 Actual	Fiscal 2016 Actual	Fiscal 2017 Actual	Fiscal 2018 Actual
Cumulative Savings (GWh/year)	0.09	0.36	1.60	1.64	1.80
Bill Savings associated with Cumulative Savings ($ 000)	8	37	162	166	186

Forecast bill savings during the test period for customers participating in the new Non-Integrated Areas program are shown in the table below.

	Fiscal 2020 Plan	Fiscal 2021 Plan
New Incremental Savings (GWh/year)	0.45	0.61
Estimated Bill Savings ($ 000)	52	72

In its response to Zone II RPG IR 1.6.1.1, BC Hydro provided the following response:

BC Hydro is in the process of assessing the pilot work conducted between

fiscal 2017 and fiscal 2019 in the Non-Integrated Areas and expects to complete a report towards the end of fiscal 2020.

In its response to Zone II RPG IR 1.26.9.1, BC Hydro stated:

Ramping up participating levels and achieving expected savings will be a challenge. BC Hydro is addressing these challenges by:

- *Minimizing BC Hydro's program requirements, where possible. BC Hydro is in the process of hiring a new Relationship Lead to assist the communities and local contractors.*

- *Designing the program to enable Indigenous communities to lead implementation of the offer within their communities.*
- *Continuing to utilize communication channels in NIA communities that were established during pilot initiatives, increasing awareness of BC Hydro's energy conservation efforts with customers, Indigenous bands and trade allies.*
- *Using proven technologies and processes and implementing projects similar to those that BC Hydro has analyzed for savings potential in the past.*
- *Applying learnings from pilot initiatives with Indigenous and remote communities. For example, BC Hydro found that weatherization upgrades were at times limited by health and safety issues in the home such as mould/moisture, presence of pests, asbestos, radon, etc. To deal with this, we've incorporated a rebate for health and safety upgrades to enable additional weatherization upgrades and energy savings to occur.*

2.48.1 Explain the reasons for the significant increase in energy and bill savings in fiscal 2016 vs. fiscal 2015 for DSM activities in NIA?

2.48.1.1 Provide reasons why this yearly increase in both bill savings and energy savings was not sustainable into future years.

RESPONSE:

The increase in energy and bill savings did not continue after fiscal 2016 because the project that was processed through the Home Renovation Rebate program in fiscal 2016, which amalgamated a high volume of individual heat pumps was unique. Similar large bulk applications were not processed in subsequent years and we do not anticipate another large application in the test period.

48.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan

Reference: Exhibit B-6, Zone II RPG IR 1.23.2, 1.23.4, 1.26.1.1, I.26.9.1

In its response to Zone II RPG IR 1.23.2 and 1.23.4, BC Hydro provided the following tables:

DSM activities in the last five years have reduced the bills for participating Non-Integrated Areas customers, as shown in the table below.

	Fiscal 2014 Actual	Fiscal 2015 Actual	Fiscal 2016 Actual	Fiscal 2017 Actual	Fiscal 2018 Actual
Cumulative Savings (GWh/year)	0.09	0.36	1.60	1.64	1.80
Bill Savings associated with Cumulative Savings ($ 000)	8	37	162	166	186

Forecast bill savings during the test period for customers participating in the new Non-Integrated Areas program are shown in the table below.

	Fiscal 2020 Plan	Fiscal 2021 Plan
New Incremental Savings (GWh/year)	0.45	0.61
Estimated Bill Savings ($ 000)	52	72

In its response to Zone II RPG IR 1.6.1.1, BC Hydro provided the following response:

BC Hydro is in the process of assessing the pilot work conducted between

fiscal 2017 and fiscal 2019 in the Non-Integrated Areas and expects to complete a report towards the end of fiscal 2020.

In its response to Zone II RPG IR 1.26.9.1, BC Hydro stated:

Ramping up participating levels and achieving expected savings will be a challenge. BC Hydro is addressing these challenges by:

- *Minimizing BC Hydro's program requirements, where possible. BC Hydro is in the process of hiring a new Relationship Lead to assist the communities and local contractors.*
- *Designing the program to enable Indigenous communities to lead implementation of the offer within their communities.*

- *Continuing to utilize communication channels in NIA communities that were established during pilot initiatives, increasing awareness of BC Hydro's energy conservation efforts with customers, Indigenous bands and trade allies.*
- *Using proven technologies and processes and implementing projects similar to those that BC Hydro has analyzed for savings potential in the past.*
- *Applying learnings from pilot initiatives with Indigenous and remote communities. For example, BC Hydro found that weatherization upgrades were at times limited by health and safety issues in the home such as mould/moisture, presence of pests, asbestos, radon, etc. To deal with this, we've incorporated a rebate for health and safety upgrades to enable additional weatherization upgrades and energy savings to occur.*

2.48.2 In its response to Zone II RPG IR 1.26.9.1, BC Hydro has provided a list of actions to address the challenges of ramping up participating levels and achieving expected savings. If the new incremental savings (GWh/year) and estimated bill savings ($000) in BC Hydro's response to Zone II RPG IR 1.23.4 do not occur during the test period, what actions will BC Hydro undertake to respond? Please explain.

RESPONSE:

BC Hydro's approach to the management of DSM initiatives is informed by the identification and assessment of delivery challenges and the development of mitigation measures at various stages of DSM implementation. BC Hydro's response to ZONE II RPG IR 1.26.9.1 provides a summary of these challenges and mitigation measures as we have formulated them prior to program launch.

During program implementation over the test period, BC Hydro will track program electricity savings and expenditures. If these results are not tracking to plan, BC Hydro can take a number of actions, such as:

- **Modifying program communication and awareness;**
- **Modifying the program application process or eligibility criteria;**
- **Modifying program incentives;**
- **Modifying the program approach, and**
- **Revising the list of qualifying products.**

In this way, BC Hydro's management activities monitor and assess performance results on an ongoing basis, to keep initiatives on track.

Zone II Ratepayers Group Information Request No. **2.48.3** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 2
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit:** **B-13**

48.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan

Reference: Exhibit B-6, Zone II RPG IR 1.23.2, 1.23.4, 1.26.1.1, I.26.9.1

In its response to Zone II RPG IR 1.23.2 and 1.23.4, BC Hydro provided the following tables:

DSM activities in the last five years have reduced the bills for participating Non-Integrated Areas customers, as shown in the table below.

	Fiscal 2014 Actual	Fiscal 2015 Actual	Fiscal 2016 Actual	Fiscal 2017 Actual	Fiscal 2018 Actual
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Forecast bill savings during the test period for customers participating in the new Non-Integrated Areas program are shown in the table below.

	Fiscal 2020 Plan	Fiscal 2021 Plan
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Estimated Bill Savings ($ 000)	52	72

In its response to Zone II RPG IR 1.6.1.1, BC Hydro provided the following response:

BC Hydro is in the process of assessing the pilot work conducted between

fiscal 2017 and fiscal 2019 in the Non-Integrated Areas and expects to complete a report towards the end of fiscal 2020.

In its response to Zone II RPG IR 1.26.9.1, BC Hydro stated:

Ramping up participating levels and achieving expected savings will be a challenge. BC Hydro is addressing these challenges by:

- *Minimizing BC Hydro's program requirements, where possible. BC Hydro is in the process of hiring a new Relationship Lead to assist the communities and local contractors.*

- *Designing the program to enable Indigenous communities to lead implementation of the offer within their communities.*
- *Continuing to utilize communication channels in NIA communities that were established during pilot initiatives, increasing awareness of BC Hydro's energy conservation efforts with customers, Indigenous bands and trade allies.*
- *Using proven technologies and processes and implementing projects similar to those that BC Hydro has analyzed for savings potential in the past.*
- *Applying learnings from pilot initiatives with Indigenous and remote communities. For example, BC Hydro found that weatherization upgrades were at times limited by health and safety issues in the home such as mould/moisture, presence of pests, asbestos, radon, etc. To deal with this, we've incorporated a rebate for health and safety upgrades to enable additional weatherization upgrades and energy savings to occur.*

2.48.3 Confirm, or explain otherwise, if BC Hydro plans to make the report on the assessment of the pilot work in the NIA available to the public or file this report with the BCUC.

RESPONSE:

BC Hydro will make this report available to interested parties such as communities that participated in the pilot, the inter-agency network facilitated by MEMPR and the Low Income Advisory Council. The report will also be available to the BCUC on request.

49.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan (Low Income Program)

Reference: Exhibit B-6, Zone II RPG IR 1.25.4

In BC Hydro's response to Zone II RPG IR 1.25.4, BC Hydro states:

BC Hydro's accounting system is not set up to track actual expenditures by program sub-category; therefore actual expenditures are only available at the program level.

	F2015	F2016	F2017	F2018	F2019 Forecast
Actuals					
Program Expenditures ($ million)[1]					
• Energy Savings Kits	n/a	n/a	n/a	n/a	0.5
• Energy Conservation Savings Program	n/a	n/a	n/a	n/a	2.2
• Fixed Program Expenditures[2]	n/a	n/a	n/a	n/a	1.1
Total	1.9	2.4	2.9	3.5	3.8
Plan					
Program Expenditures ($ million)[1]					
• Energy Savings Kits	0.5	0.5	0.5	0.5	0.5
• Energy Conservation Savings Program	1.0	1.0	1.0	1.1	1.1
• Fixed Program Expenditures[2]	1.0	1.0	1.0	1.1	1.1
Total	2.5	2.5	2.5	2.6	2.7
Variance					
Program Expenditures ($ million)[1]					
• Energy Savings Kits	n/a	n/a	n/a	n/a	0.0
• Energy Conservation Savings Program	n/a	n/a	n/a	n/a	1.1
• Fixed Program Expenditures[2]	n/a	n/a	n/a	n/a	0.0
Total	-0.6	-0.1	0.4	0.9	1.2

Notes:
1. BC Hydro's accounting system was not setup to track by sub-category; therefore actual expenditures are only available at the program level.
2. Fixed Program Expenditures are not allocated to individual Program components.

2.49.1 Confirm, or explain otherwise, that BC Hydro will track actual expenditures by program sub-category for the test period.

RESPONSE:

Confirmed. BC Hydro will track actual incentive expenditures for the Low Income Program at the offer sub-category level for the test period.

50.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan (Low Income Program)

Reference: Exhibit B-6, Zone II RPG IR 1.25.6, 1.26.6.1; Exhibit B-23, 2015 RDA, Zone II RPG IR 2.26.3

In BC Hydro's responses to Zone II RPG IR 1.25.6, BC Hydro provides the following table on how many ECAP applications were submitted, approved and rejected:

Applications Approved and Declined By Fiscal 2014 to Fiscal 2018

	Participant Category	Approved and Declined Applications	Approved	Declined
F14	Integrated non-Indigenous	1,533	1,369	164
	Integrated Indigenous	813	764	49
	Non-Integrated non-Indigenous	1	1	0
	Non-Integrated Indigenous	1	1	0
	Total	2,348	2,135	213
F15	Integrated non-Indigenous	1,231	1,119	112
	Integrated Indigenous	147	138	9
	Non-Integrated non-Indigenous	0	0	0
	Non-Integrated Indigenous	0	0	0
	Total	1,378	1,257	121
F16	Integrated non-Indigenous	1,599	1,485	114
	Integrated Indigenous	382	380	2
	Non-Integrated non-Indigenous	0	0	0
	Non-Integrated Indigenous	0	0	0
	Total	1,981	1,865	116
F17	Integrated non-Indigenous	1,657	1,560	97
	Integrated Indigenous	277	277	0
	Non-Integrated non-Indigenous	8	8	0
	Non-Integrated Indigenous	0	0	0
	Total	1,942	1,845	97
F18	Integrated non-Indigenous	2,389	2,324	65

Participant Category	Approved and Declined Applications	Approved	Declined
Integrated Indigenous	481	452	29
Non-integrated non-Indigenous	10	10	0
Non-integrated Indigenous	5	5	0
Total	2,885	2,791	94

In response to IR 25.6.1, BC Hydro provided the following table to provide reasons for applications being rejected.

	Participant Category	Already Received ECAP	Did not Meet Consumption Criteria	Apartment Dwelling	Income Exceeds Qualification Criteria	Other	Total Declined
	Integrated	19	87	4	53	1	164
F14	Integrated Indigenous	0	49	0	0	0	49
	Total	19	136	4	53	1	213
	Integrated	37	0	10	64	1	112
F15	Integrated Indigenous	9	0	0	0	0	9
	Total	46	0	10	64	1	121
	Integrated	45	0	33	32	4	114
F16	Integrated Indigenous	2	0	0	0	0	2
	Total	47	0	33	32	4	116
	Integrated	41	0	28	28		97
F17	Integrated Indigenous	0	0	0	0	0	0
	Total	41	0	28	28	0	97
	Integrated	29	0	6	29	1	65
F18	Integrated Indigenous	29	0	0	0	0	29
	Total	58	0	6	29	1	94

In BC Hydro's response to ZoneIIRPG 2.26.3 in the 2015 RDA:

Out of the 111 homes that participated, only 26 were in housing types that would have been potentially eligible for ECAP Advanced offering from BC Hydro (i.e., electrically heated in a single family, townhome or duplex). The majority of the 85 remaining participants were gas heated. Some of those homes may have received advanced measures from FortisBC (insulation or furnace replacement).

Of the 26, one did receive upgrades in F2016 (along with 11 other electrically heated First Nation homes that received insulation upgrades in F2016.)

The 25 homes that did not receive additional upgrades under ECAP Advanced did not meet program criteria for further measures. Eligibility criteria for measures include: existing low levels of insulation, sufficient access, no significant existing health and safety issues that would prevent further work (e.g., no vermiculite present), as well, the customer must consent to the upgrades.

2.50.1 Provide the breakdown of the ECAP category into Basic and Advanced ECAP for the tables BC Hydro provided.

RESPONSE

No breakdown of the table can be provided because the ECAP offer of the Low Income Program accepts or declines applications at the beginning of the ECAP process and it is not specific to the basic or weatherization (advanced) streams.

ECAP operates as a single offer with two streams: basic and weatherization (or Advanced) stream. The tables provided in BC Hydro's response to ZONE II RPG IRs 1.25.6 and 1.25.6.1 show the number of approved and declined ECAP applications and the reasons for being declined. The approval of the application happens at the time the customer applies for ECAP. All customers who are approved for ECAP are considered for measures offered in the weatherization stream (or Advanced stream). No separate application is required.

More details on the two streams are provided in BC Hydro's response to ZONE II RPG IR 2.50.1.1 and information on ECAP participants that did not move forward to ECAP weatherization is provided in BC Hydro's response to ZONE II RPG IR 2.50.1.5.1.

50.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan (Low Income Program)

Reference: Exhibit B-6, Zone II RPG IR 1.25.6, 1.26.6.1; Exhibit B-23, 2015 RDA, Zone II RPG IR 2.26.3

In BC Hydro's responses to Zone II RPG IR 1.25.6, BC Hydro provides the following table on how many ECAP applications were submitted, approved and rejected:

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	Total	1,378	1,257	121
F16	Integrated non-Indigenous	1,599	1,485	114
	Integrated Indigenous	382	380	2
	Non-Integrated non-Indigenous	0	0	0
	Non-Integrated Indigenous	0	0	0
	Total	1,981	1,865	116
F17	Integrated non-Indigenous	1,657	1,560	97
	Integrated Indigenous	277	277	0
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	Non-Integrated Indigenous	0	0	0
	Total	1,942	1,845	97
F18	Integrated non-Indigenous	2,389	2,324	65

	Participant Category	Approved and Declined Applications	Approved	Declined
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	Non-integrated Indigenous	5	5	0
	Total	2,885	2,791	94

In response to IR 25.6.1, BC Hydro provided the following table to provide reasons for applications being rejected.

	Participant Category	Already Received ECAP	Did not Meet Consumption Criteria	Apartment Dwelling	Income Exceeds Qualification Criteria	Other	Total Declined
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	Integrated Indigenous	0	0	0	0	0	0
	Total	41	0	28	28	0	97
F18	Integrated	29	0	6	29	1	65
	Integrated Indigenous	29	0	0	0	0	29
	Total	58	0	6	29	1	94

In BC Hydro's response to ZoneIIRPG 2.26.3 in the 2015 RDA:

Out of the 111 homes that participated, only 26 were in housing types that would have been potentially eligible for ECAP Advanced offering from BC Hydro (i.e., electrically heated in a single family, townhome or duplex). The majority of the 85 remaining participants were gas heated. Some of those homes may have received advanced measures from FortisBC (insulation or furnace replacement).

Of the 26, one did receive upgrades in F2016 (along with 11 other electrically heated First Nation homes that received insulation upgrades in F2016.)

The 25 homes that did not receive additional upgrades under ECAP Advanced did not meet program criteria for further measures. Eligibility criteria for measures include: existing low levels of insulation, sufficient access, no significant existing health and safety issues that would prevent further work (e.g., no vermiculite present), as well, the customer must consent to the upgrades.

2.50.1 Provide the breakdown of the ECAP category into Basic and Advanced ECAP for the tables BC Hydro provided.

2.50.1.1 Describe the Basic and Advanced ECAP programs and the measures they offer

RESPONSE:

ECAP operates as a single offer with two streams: basic and weatherization (or Advanced) streams.

Basic Stream Overview

All applicants who are approved for ECAP begin in the basic stream. This involves:

- **A home visit by a program energy coach;**
- **Review and data collection of how the home uses energy (including an estimate of insulation levels, heating fuel sources etc.);**
- **Installation of eligible energy saving measures; and**
- **Personalized energy saving tips.**

Measures eligible for installation as part of the basic stream are:

- **LED bulbs (A-lamps, globes, specialty bulbs);**
- **Showerheads, faucet aerators;**
- **Door weather stripping, draft proofing;**
- **Pipe Wrap;**
- **Carbon Monoxide Detector(s);**
- **Dryer Rack or Clothes line;**

- **Fridge Thermometer; and**
- **Energy Star Refrigerator.**

Weatherization (Advanced) Stream Overview

Based on the home's needs assessment at the basic visit, electrically space heated homes[1] with moderate insulation levels may qualify for a weatherization assessment to determine if weatherization measures can be installed. Further home visits will be booked to install the eligible measures.

Measures eligible for installation during the weatherization phase include:

- **Insulation;**
- **Draft proofing;**
- **Programmable Thermostats; and**
- **Ventilation System.**

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[1] **ECAP operates in partnership with FortisBC Energy Inc. FortisBC gas heated homes may be eligible for insulation upgrades and high-efficiency natural gas furnace replacement funded by Fortis through the program using the same process described for electrically heated homes.**

50.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan (Low Income Program)

Reference: Exhibit B-6, Zone II RPG IR 1.25.6, 1.26.6.1; Exhibit B-23, 2015 RDA, Zone II RPG IR 2.26.3

In BC Hydro's responses to Zone II RPG IR 1.25.6, BC Hydro provides the following table on how many ECAP applications were submitted, approved and rejected:

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	Total	1,981	1,865	116
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	Integrated Indigenous	277	277	0
	Non-Integrated non-Indigenous	8	8	0
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	Total	1,942	1,845	97
F18	Integrated non-Indigenous	2,389	2,324	65

	Participant Category	Approved and Declined Applications	Approved	Declined
	Integrated Indigenous	481	452	29
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	Total	2,885	2,791	94

In response to IR 25.6.1, BC Hydro provided the following table to provide reasons for applications being rejected.

	Participant Category	Already Received ECAP	Did not Meet Consumption Criteria	Apartment Dwelling	Income Exceeds Qualification Criteria	Other	Total Declined
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In BC Hydro's response to ZoneIIRPG 2.26.3 in the 2015 RDA:

Out of the 111 homes that participated, only 26 were in housing types that would have been potentially eligible for ECAP Advanced offering from BC Hydro (i.e., electrically heated in a single family, townhome or duplex). The majority of the 85 remaining participants were gas heated. Some of those homes may have received advanced measures from FortisBC (insulation or furnace replacement).

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2.50.1 Provide the breakdown of the ECAP category into Basic and Advanced ECAP for the tables BC Hydro provided.

2.50.1.2 Confirm or explain otherwise if there has been changes to the Basic and Advanced ECAP program measures for the test period.

RESPONSE:

Please refer to BC Hydro's response to ZONE II RPG IR 2.43.1 for a list of measure changes and offer enhancements for the test period.

50.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan (Low Income Program)

Reference: Exhibit B-6, Zone II RPG IR 1.25.6, 1.26.6.1; Exhibit B-23, 2015 RDA, Zone II RPG IR 2.26.3

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2.50.1 Provide the breakdown of the ECAP category into Basic and Advanced ECAP for the tables BC Hydro provided.

2.50.1.3 Confirm, or explain otherwise, whether the data provided includes any pilot activities in the NIA.

RESPONSE:

The data does not include any pilot activities in the NIA.

50.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan (Low Income Program)

Reference: Exhibit B-6, Zone II RPG IR 1.25.6, 1.26.6.1; Exhibit B-23, 2015 RDA, Zone II RPG IR 2.26.3

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	Non-integrated Indigenous	0	0	0
	Total	1,942	1,845	97
F18	Integrated non-Indigenous	2,389	2,324	65

	Participant Category	Approved and Declined Applications	Approved	Declined
	Integrated Indigenous	481	452	29
	Non-integrated non-Indigenous	10	10	0
	Non-integrated Indigenous	5	5	0
	Total	2,885	2,791	94

In response to IR 25.6.1, BC Hydro provided the following table to provide reasons for applications being rejected.

	Participant Category	Already Received ECAP	Did not Meet Consumption Criteria	Apartment Dwelling	Income Exceeds Qualification Criteria	Other	Total Declined
F14	Integrated	19	87	4	53	1	164
	Integrated Indigenous	0	49	0	0	0	49
	Total	19	136	4	53	1	213
F15	Integrated	37	0	10	64	1	112
	Integrated Indigenous	9	0	0	0	0	9
	Total	46	0	10	64	1	121
F16	Integrated	45	0	33	32	4	114
	Integrated Indigenous	2	0	0	0	0	2
	Total	47	0	33	32	4	116
F17	Integrated	41	0	28	28		97
	Integrated Indigenous	0	0	0	0	0	0
	Total	41	0	28	28	0	97
F18	Integrated	29	0	6	29	1	65
	Integrated Indigenous	29	0	0	0	0	29
	Total	58	0	6	29	1	94

In BC Hydro's response to ZoneIIRPG 2.26.3 in the 2015 RDA:

Out of the 111 homes that participated, only 26 were in housing types that would have been potentially eligible for ECAP Advanced offering from BC Hydro (i.e., electrically heated in a single family, townhome or duplex). The majority of the 85 remaining participants were gas heated. Some of those homes may have received advanced measures from FortisBC (insulation or furnace replacement).

Of the 26, one did receive upgrades in F2016 (along with 11 other electrically heated First Nation homes that received insulation upgrades in F2016.)

The 25 homes that did not receive additional upgrades under ECAP Advanced did not meet program criteria for further measures. Eligibility criteria for measures include: existing low levels of insulation, sufficient access, no significant existing health and safety issues that would prevent further work (e.g., no vermiculite present), as well, the customer must consent to the upgrades.

2.50.1 Provide the breakdown of the ECAP category into Basic and Advanced ECAP for the tables BC Hydro provided.

2.50.1.4 Confirm, or explain otherwise, that customers can only receive ECAP one-time.

RESPONSE:

A dwelling is eligible for the ECAP program once every 10 years. An account holder who has previously participated in ECAP (less than 10 years ago) but has moved is eligible to apply to participate at their new address.

50.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan (Low Income Program)

Reference: Exhibit B-6, Zone II RPG IR 1.25.6, 1.26.6.1; Exhibit B-23, 2015 RDA, Zone II RPG IR 2.26.3

In BC Hydro's responses to Zone II RPG IR 1.25.6, BC Hydro provides the following table on how many ECAP applications were submitted, approved and rejected:

Applications Approved and Declined By Fiscal 2014 to Fiscal 2018

	Participant Category	Approved and Declined Applications	Approved	Declined
F14	Integrated non-Indigenous	1,533	1,369	164
	Integrated Indigenous	813	764	49
	Non-integrated non-Indigenous	1	1	0
	Non-integrated Indigenous	1	1	0
	Total	2,348	2,135	213
F15	Integrated non-Indigenous	1,231	1,119	112
	Integrated Indigenous	147	138	9
	Non-integrated non-Indigenous	0	0	0
	Non-integrated Indigenous	0	0	0
	Total	1,378	1,257	121
F16	Integrated non-Indigenous	1,599	1,485	114
	Integrated Indigenous	382	380	2
	Non-integrated non-Indigenous	0	0	0
	Non-integrated Indigenous	0	0	0
	Total	1,981	1,865	116
F17	Integrated non-Indigenous	1,657	1,560	97
	Integrated Indigenous	277	277	0
	Non-integrated non-Indigenous	8	8	0
	Non-integrated Indigenous	0	0	0
	Total	1,942	1,845	97
F18	Integrated non-Indigenous	2,389	2,324	65

Participant Category	Approved and Declined Applications	Approved	Declined
Integrated Indigenous	481	452	29
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	Total	41	0	28	28	0	97
F18	Integrated	29	0	6	29	1	65
	Integrated Indigenous	29	0	0	0	0	29
	Total	58	0	6	29	1	94

In BC Hydro's response to ZoneIIRPG 2.26.3 in the 2015 RDA:

Out of the 111 homes that participated, only 26 were in housing types that would have been potentially eligible for ECAP Advanced offering from BC Hydro (i.e., electrically heated in a single family, townhome or duplex). The majority of the 85 remaining participants were gas heated. Some of those homes may have received advanced measures from FortisBC (insulation or furnace replacement).

Of the 26, one did receive upgrades in F2016 (along with 11 other electrically heated First Nation homes that received insulation upgrades in F2016.)

The 25 homes that did not receive additional upgrades under ECAP Advanced did not meet program criteria for further measures. Eligibility criteria for measures include: existing low levels of insulation, sufficient access, no significant existing health and safety issues that would prevent further work (e.g., no vermiculite present), as well, the customer must consent to the upgrades.

2.50.1.4 Confirm, or explain otherwise, that customers can only receive ECAP one-time.

2.50.1.4.1 If this requirement is based on the dwelling or the account holder?

RESPONSE:

The requirement is based on the dwelling as explained in BC Hydro's response to ZONE II RPG IR 2.50.1.4.1.

50.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan (Low Income Program)

Reference: Exhibit B-6, Zone II RPG IR 1.25.6, 1.26.6.1; Exhibit B-23, 2015 RDA, Zone II RPG IR 2.26.3

In BC Hydro's responses to Zone II RPG IR 1.25.6, BC Hydro provides the following table on how many ECAP applications were submitted, approved and rejected:

Applications Approved and Declined By Fiscal 2014 to Fiscal 2018

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	Non-Integrated non-Indigenous	0	0	0
	Non-Integrated Indigenous	0	0	0
	Total	1,378	1,257	121
F16	Integrated non-Indigenous	1,599	1,485	114
	Integrated Indigenous	382	380	2
	Non-Integrated non-Indigenous	0	0	0
	Non-Integrated Indigenous	0	0	0
	Total	1,981	1,865	116
F17	Integrated non-Indigenous	1,657	1,560	97
	Integrated Indigenous	277	277	0
	Non-Integrated non-Indigenous	8	8	0
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	Integrated Indigenous	29	0	0	0	0	29
	Total	58	0	6	29	1	94

In BC Hydro’s response to ZoneIIRPG 2.26.3 in the 2015 RDA:

Out of the 111 homes that participated, only 26 were in housing types that would have been potentially eligible for ECAP Advanced offering from BC Hydro (i.e., electrically heated in a single family, townhome or duplex). The majority of the 85 remaining participants were gas heated. Some of those homes may have received advanced measures from FortisBC (insulation or furnace replacement).

Of the 26, one did receive upgrades in F2016 (along with 11 other electrically heated First Nation homes that received insulation upgrades in F2016.)

The 25 homes that did not receive additional upgrades under ECAP Advanced did not meet program criteria for further measures. Eligibility criteria for measures include: existing low levels of insulation, sufficient access, no significant existing health and safety issues that would prevent further work (e.g., no vermiculite present), as well, the customer must consent to the upgrades.

2.50.1 Provide the breakdown of the ECAP category into Basic and Advanced ECAP for the tables BC Hydro provided.

2.50.1.5 Confirm, or explain otherwise, if declined applications include any for further ECAP Advanced measures beyond the Basic ECAP.

RESPONSE:

A declined ECAP application would not receive any measures through the ECAP offer. Please refer to BC Hydro's response to ZONE II RPG IR 2.50.1 for information about declined ECAP applications.

50.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan (Low Income Program)

Reference: Exhibit B-6, Zone II RPG IR 1.25.6, 1.26.6.1; Exhibit B-23, 2015 RDA, Zone II RPG IR 2.26.3

In BC Hydro's responses to Zone II RPG IR 1.25.6, BC Hydro provides the following table on how many ECAP applications were submitted, approved and rejected:

Applications Approved and Declined By Fiscal 2014 to Fiscal 2018

	Participant Category	Approved and Declined Applications	Approved	Declined
F14	Integrated non-Indigenous	1,533	1,369	164
	Integrated Indigenous	813	764	49
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	Non-Integrated Indigenous	1	1	0
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	Integrated Indigenous	147	138	9
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	Non-Integrated Indigenous	0	0	0
	Total	1,378	1,257	121
F16	Integrated non-Indigenous	1,599	1,485	114
	Integrated Indigenous	382	380	2
	Non-Integrated non-Indigenous	0	0	0
	Non-Integrated Indigenous	0	0	0
	Total	1,981	1,865	116
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	Participant Category	Already Received ECAP	Did not Meet Consumption Criteria	Apartment Dwelling	Income Exceeds Qualification Criteria	Other	Total Declined
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	Total	47	0	33	32	4	116
F17	Integrated	41	0	28	28		97
	Integrated Indigenous	0	0	0	0	0	0
	Total	41	0	28	28	0	97
F18	Integrated	29	0	6	29	1	65
	Integrated Indigenous	29	0	0	0	0	29
	Total	58	0	6	29	1	94

In BC Hydro's response to ZoneIIRPG 2.26.3 in the 2015 RDA:

Out of the 111 homes that participated, only 26 were in housing types that would have been potentially eligible for ECAP Advanced offering from BC Hydro (i.e., electrically heated in a single family, townhome or duplex). The majority of the 85 remaining participants were gas heated. Some of those homes may have received advanced measures from FortisBC (insulation or furnace replacement).

Of the 26, one did receive upgrades in F2016 (along with 11 other electrically heated First Nation homes that received insulation upgrades in F2016.)

The 25 homes that did not receive additional upgrades under ECAP Advanced did not meet program criteria for further measures. Eligibility criteria for measures include: existing low levels of insulation, sufficient access, no significant existing health and safety issues that would prevent further work (e.g., no vermiculite present), as well, the customer must consent to the upgrades.

2.50.1.5 Confirm, or explain otherwise, if declined applications include any for further ECAP Advanced measures beyond the Basic ECAP.

2.50.1.5.1 Provide data for the ECAP participants that were declined for further measures under the ECAP Advanced; including the reasons for being declined.

RESPONSE:

The ECAP stream of the Low Income Program accepts or declines applications at the beginning of the ECAP process. Once a customer is accepted into ECAP, a home visit is conducted and a needs assessment is performed to determine what products can be installed by the on-site crew at the time of this initial visit. The need's assessment of the home may show that additional insulation is not needed. In those cases, no further measures are offered to the participant. In cases where the participant's needs assessment shows that there may be potential for additional measures, a weatherization assessment is scheduled and completed. In some cases, the weatherization assessment shows that the home does meet program criteria for further measures beyond what was installed at the initial visit. Approximately 30 per cent of homes receiving weatherization assessments are not eligible for additional measures and these customers are then advised that their ECAP participation is now complete.

In the past, the most common reason for a home not qualifying for additional insulation following a weatherization assessment was because existing insulation levels were higher than the program criteria. To address this issue, in fiscal 2019 ECAP began installing insulation in homes with higher existing insulation levels on an exception basis. Program policy has now changed to enable insulation to be installed in homes with modest rather than just low levels of insulation.

These changes resulted in a substantial increase in the percentage of homes receiving insulation upgrades. This increase is shown in the table below.

Electrically Heated ECAP homes receiving weatherization upgrades

Fiscal Year	%
2017	9.4
2018	11.7
2019	22.0

With the change in insulation levels, the highest single reason for insulation work not moving forward after a weatherization assessment is now failure of the combustion spillage test, which measures the unwanted flow of combustion gases into a home. Investigation is planned to determine if there are feasible options for addressing this complex issue.

51.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan (Non-Integrated Areas)

Reference: Exhibit B-6, Zone II RPG IR 1.26.3.2

In BC Hydro's response to Zone II RPG IR 1.26.3.2, BC Hydro stated the following:

We did not look to other jurisdictions/utilities to determine the appropriate level of funding for Demand-Side Management (DSM) in the new Non-Integrated Area program. We do not have information on funding levels for DSM in other jurisdictions that have non-integrated loads.

2.51.1 Provide reasons why BC Hydro did not look to other jurisdictions/utilities to determine and inform the appropriate level of funding and types of programs for the new NIA program.

RESPONSE:

The level of funding and types of programs were determined by the specific needs in B.C. and not the needs in other jurisdictions.

51.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan (Non-Integrated Areas)

Reference: Exhibit B-6, Zone II RPG IR 1.26.3.2

In BC Hydro's response to Zone II RPG IR 1.26.3.2, BC Hydro stated the following:

We did not look to other jurisdictions/utilities to determine the appropriate level of funding for Demand-Side Management (DSM) in the new Non-Integrated Area program. We do not have information on funding levels for DSM in other jurisdictions that have non-integrated loads.

2.51.2 Since this is the first year of the new NIA program, is there flexibility within BC Hydro's DSM budget to increase spending on this program should there be more DSM spending than budgeted during the test period?

RESPONSE:

As described in BC Hydro's response to BCUC IR 1.174.1, managing programs and the overall DSM portfolio can result in adjustments and the reallocation of costs during the Test Period. BC Hydro would assess changes to a DSM program's budget on a case-by-case basis and increases to program budgets would depend on whether other initiatives in the portfolio are underspent relative to their budget.

BC Hydro manages its DSM portfolio as circumstances occur, so it is not possible to speculate on what specific impacts any potential increased spending by the Non-Integrated Areas program would have on other DSM components.

51.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan (Non-Integrated Areas)

Reference: Exhibit B-6, Zone II RPG IR 1.26.3.2

In BC Hydro's response to Zone II RPG IR 1.26.3.2, BC Hydro stated the following:

We did not look to other jurisdictions/utilities to determine the appropriate level of funding for Demand-Side Management (DSM) in the new Non-Integrated Area program. We do not have information on funding levels for DSM in other jurisdictions that have non-integrated loads.

2.51.2 Since this is the first year of the new NIA program, is there flexibility within BC Hydro's DSM budget to increase spending on this program should there be more DSM spending than budgeted during the test period?

2.51.2.1 If yes, please explain including the impact to other components of BC Hydro's DSM budget.

RESPONSE:

Please refer to BC Hydro's response to ZONE II RPG IR 2.51.2 where we explain that BC Hydro cannot speculate on the potential impact to other components of the DSM portfolio.

52.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan (Non-Integrated Areas)

Reference: Exhibit B-6, Zone II RPG IR 1.26.3.1, BCUC IR 1.185.2.1.

In BC Hydro's response to BCUC IR 1.185.2.1, BC Hydro provided Attachment 1.

Non-Integrated Areas Program-level Assumptions Summary

Customer Segment/offer: Residential Weatherization (Direct Install)

Assumption	Fiscal 2020 Plan	Fiscal 2021 Plan	Fiscal 2022 Plan
Participation	60	80	80
Savings/participant (kWh/yr)	2,945	2,945	2,945
Incentive $/participant	$5,941	$6,060	$6,181
Variable Program Cost $/participant	$255	$260	$265
Customer Cost $/participant	$5,941	$6,060	$6,181
Net-to-Gross Ratio	0.846	0.846	0.846

Customer Segment/offer: Residential Energy Savings Kit (Direct Install)

Assumption	Fiscal 2020 Plan	Fiscal 2021 Plan	Fiscal 2022 Plan
Participation	160	200	200
Savings/participant (kWh/yr)	1,325	1,185	1,185
Incentive $/participant	$422	$431	$439
Variable Program Cost $/participant	$51	$52	$53
Customer Cost $/participant*	$160	$162	$166
Net-to-Gross Ratio	0.465	0.465	0.465

* customer costs are less than incentive costs because the lighting component of the offer has negative customer costs

Customer Segment/offer: Residential Fridge & Freezer offer

Assumption	Fiscal 2020 Plan	Fiscal 2021 Plan	Fiscal 2022 Plan
Participation	50	60	60
Savings/participant (kWh/yr)	814	814	814
Incentive $/participant	$1,350	$1,377	$1,405
Variable Program Cost $/participant	$0	$0	$0
Customer Cost $/participant	$1,350	$1,377	$1,405
Net-to-Gross Ratio	0.884	0.884	0.884

Customer Segment/offer: Residential Heat Pump

Assumption	Fiscal 2020 Plan	Fiscal 2021 Plan	Fiscal 2022 Plan
Participation	20	25	30
Savings/participant (kWh/yr)	2,820	2,820	2,820
Incentive $/participant	$1,020	$1,040	$1,061
Variable Program Cost $/participant	$128	$130	$133
Customer Cost $/participant	$5,916	$6,034	$6,155
Net-to-Gross Ratio	0.893	0.893	0.893

Customer Segment/offer: Commercial Small/Medium Business Lighting

Assumption	Fiscal 2020 Plan	Fiscal 2021 Plan	Fiscal 2022 Plan
Participation	10	20	20
Savings/participant (kWh/yr)	10,368	10,368	10,368
Incentive $/participant	$3,556	$3,627	$3,700
Variable Program Cost $/participant	$0	$0	$0
Customer Cost $/participant	$3,556	$3,627	$3,700
Net-to-Gross Ratio	0.806	0.806	0.806

Program Fixed Costs:

Assumption	Fiscal 2020 Plan	Fiscal 2021 Plan	Fiscal 2022 Plan
Community Support ($ millions)	$0.35	$0.36	$0.37
Fixed Program Costs ($ millions)	$0.27	$0.28	$0.28

2.52.1 Confirm, or explain otherwise, that these DSM measures are the most cost-effective for NIA communities.

RESPONSE:

This answer also responds to ZONE II RPG IR 2.52.2.

During our pilot initiative from fiscal 2017 through fiscal 2019, we worked with communities to explore program delivery approaches and Demand Side Management (DSM) measures in an effort to address the barriers that these communities face and better serve their needs from a DSM perspective. The emphasis of this pilot work was largely around program delivery approaches but also covered DSM measures. Working closely with these communities afforded us the opportunity to solicit feedback on the DSM measures provided through our existing programs and to explore the potential for other measures. As a result, we have added measures to our new program and increased incentives on certain measures to further encourage home energy upgrades. These measures have been modelled and determined to be cost-effective. As a result of this work, we believe that the DSM measures currently included in our new program are both needed and cost-effective.

We will continue to monitor the DSM measures and program delivery approaches to understand their cost effectiveness and how they are meeting the needs of communities.

Zone II Ratepayers Group Information Request No. **2.52.2** Dated: **August 1, 2019** British Columbia Hydro & Power Authority Response issued **September 3, 2019**	Page 1 of 2
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit:** **B-13**

52.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan (Non-Integrated Areas)

Reference: Exhibit B-6, Zone II RPG IR 1.26.3.1, BCUC IR 1.185.2.1.

In BC Hydro's response to BCUC IR 1.185.2.1, BC Hydro provided Attachment 1.

Non-Integrated Areas Program-level Assumptions Summary

Customer Segment/offer: Residential Weatherization (Direct Install)

Assumption	Fiscal 2020 Plan	Fiscal 2021 Plan	Fiscal 2022 Plan
Participation	60	80	80
Savings/participant (kWh/yr)	2,945	2,945	2,945
Incentive $/participant	$5,941	$6,060	$6,181
Variable Program Cost $/participant	$255	$260	$265
Customer Cost $/participant	$5,941	$6,060	$6,181
Net-to-Gross Ratio	0.846	0.846	0.846

Customer Segment/offer: Residential Energy Savings Kit (Direct Install)

Assumption	Fiscal 2020 Plan	Fiscal 2021 Plan	Fiscal 2022 Plan
Participation	160	200	200
Savings/participant (kWh/yr)	1,325	1,185	1,185
Incentive $/participant	$422	$431	$439
Variable Program Cost $/participant	$51	$52	$53
Customer Cost $/participant*	$160	$162	$168
Net-to-Gross Ratio	0.465	0.465	0.465

* customer costs are less than incentive costs because the lighting component of the offer has negative customer costs

Customer Segment/offer: Residential Fridge & Freezer offer

Assumption	Fiscal 2020 Plan	Fiscal 2021 Plan	Fiscal 2022 Plan
Participation	50	60	60
Savings/participant (kWh/yr)	814	814	814
Incentive $/participant	$1,350	$1,377	$1,405
Variable Program Cost $/participant	$0	$0	$0
Customer Cost $/participant	$1,350	$1,377	$1,405
Net-to-Gross Ratio	0.884	0.884	0.884

Customer Segment/offer: Residential Heat Pump

Assumption	Fiscal 2020 Plan	Fiscal 2021 Plan	Fiscal 2022 Plan
Participation	20	25	30
Savings/participant (kWh/yr)	2,820	2,820	2,820
Incentive $/participant	$1,020	$1,040	$1,061
Variable Program Cost $/participant	$128	$130	$133
Customer Cost $/participant	$5,916	$6,034	$6,155
Net-to-Gross Ratio	0.893	0.893	0.893

Customer Segment/offer: Commercial Small/Medium Business Lighting

Assumption	Fiscal 2020 Plan	Fiscal 2021 Plan	Fiscal 2022 Plan
Participation	10	20	20
Savings/participant (kWh/yr)	10,368	10,368	10,368
Incentive $/participant	$3,556	$3,627	$3,700
Variable Program Cost $/participant	$0	$0	$0
Customer Cost $/participant	$3,556	$3,627	$3,700
Net-to-Gross Ratio	0.806	0.806	0.806

Program Fixed Costs:

Assumption	Fiscal 2020 Plan	Fiscal 2021 Plan	Fiscal 2022 Plan
Community Support ($ millions)	$0.35	$0.36	$0.37
Fixed Program Costs ($ millions)	$0.27	$0.28	$0.28

2.52.2 Explain how BC Hydro determined that these DSM measures are the most needed in NIA communities.

RESPONSE:

Please refer to BC Hydro’s response to ZONE II RPG IR 2.52.1.

53.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan (Non-Integrated Areas)

Reference: Exhibit B-6, Zone II RPG IR 1.26.6

In its response to Zone II RPG IR 1.26.6, BC Hydro provided the following:

We recognize that there are barriers to implementing Demand-Side Management (DSM) in Non-Integrated Areas and understand that our DSM efforts may need to be sustained over several years in order to support customers in the Non-Integrated Areas with overcoming barriers and realizing energy saving opportunities. Accordingly, BC Hydro has included a multi-year Non-Integrated Areas program in our longer-term DSM planning.

2.53.1 Provide details, including funding, timing, program, etc. on BC Hydro's multi-year NIA program in its longer-term DSM planning.

RESPONSE:

Future activity beyond the Test Period will be updated in our next Integrated Resource Plan, but current high level estimates for energy saving and program costs are presented in the table below. These estimates assume a similar program offer remains in place.

Non-Integrated Areas Program Forecast

	New Incremental Energy Savings at Customer Meter (GWh/yr)	Total NIA Costs ($ million)
F2020	**0.5**	**1.2**
F2021	**0.6**	**1.4**
F2022	**0.6**	**1.5**
F2023	**0.8**	**1.6**
F2024	**0.8**	**1.8**
F2025	**0.8**	**1.8**
F2026	**0.7**	**1.8**
F2027	**0.7**	**1.7**
F2028	**0.7**	**1.7**
F2029	**0.6**	**1.5**

54.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan (Non-Integrated Areas)

Reference: Exhibit B-6, Zone II RPG IR 1.26.9.1

In its response to Zone II RPG IR 1.26.9.1, BC Hydro acknowledges that "*Ramping up participation levels and achieving expected savings will be a challenge".…There can be unique logistical challenges for the NIA program. Based on the knowledge gained through the pilot initiatives, BC Hydro has developed the following components for the NIA program to help mitigate the logistics challenges:*

……

• BC Hydro is working with other agencies to combine funding in order to support Indigenous Bands leading home renovation projects for their community, and encourage them to pursue energy efficiency upgrades during these renovation projects.

2.54.1 Please identify the "other agencies" that BC Hydro is working with to combine funding in order to support Indigenous Bands.

RESPONSE:

In BC Hydro's response to ZONE II RPG IR 1.26.8.3, we mentioned our participation in a network of federal, provincial and regional agencies that is convened and facilitated by the Ministry of Energy, Mines and Petroleum Resources. The agencies within this network are the ones we are working with to combine funding in order to support Indigenous Bands, including:

- **Canada Mortgage and Housing Corporation;**
- **Climate Action Secretariat;**
- **Columbia Basin Trust;**
- **FortisBC;**
- **Fraser Basin Council;**
- **Indigenous Services Canada;**
- **Ministry of Forests, Lands, Natural Resource Operations & Rural Development;**

- **Ministry of Energy, Mines and Petroleum Resources;**
- **Ministry of Municipal Affairs and Housing;**
- **Ministry of Indigenous Relations and Reconciliation;**
- **New Relationship Trust;**
- **Natural Resources Canada; and**
- **Western Economic Diversification Canada.**

54.0 Topic: Fiscal 2020 to Fiscal 2022 Demand-Side Management Business Plan (Non-Integrated Areas)

Reference: Exhibit B-6, Zone II RPG IR 1.26.9.1

In its response to Zone II RPG IR 1.26.9.1, BC Hydro acknowledges that "*Ramping up participation levels and achieving expected savings will be a challenge".…There can be unique logistical challenges for the NIA program. Based on the knowledge gained through the pilot initiatives, BC Hydro has developed the following components for the NIA program to help mitigate the logistics challenges:*

……

• *BC Hydro is working with other agencies to combine funding in order to support Indigenous Bands leading home renovation projects for their community, and encourage them to pursue energy efficiency upgrades during these renovation projects.*

2.54.1 Please identify the "other agencies" that BC Hydro is working with to combine funding in order to support Indigenous Bands.

2.54.1.1 Provide details on funding sources and coordinated actions plans.

RESPONSE:

The agencies listed in BC Hydro's response to ZONE II RPG IR 2.54.1 have various programs and resources aimed at supporting Indigenous communities (and local governments) in the areas of housing, infrastructure, energy efficiency and clean energy projects. The Ministry of Energy, Mines and Petroleum Resources maintains a funding guide outlining the funding programs available from these agencies (and others), which can be accessed at:

https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/community-energy-solutions/funding_opportunities_clean_community_energy_bc.pdf

As outlined in BC Hydro's response to ZONE II RPG IR 1.26.8.3.2 we are not aware of any action plans that have been developed by the inter-agency group led by the Ministry of Energy, Mines and Petroleum Resources.

55.0 Topic: Low Carbon Electrification Program

Reference: Exhibit B-6, Zone II RPG IR 1.27.1.1

In its response to Zone II RPG IR 1.27.1.1, BC Hydro confirmed that:

BC Hydro did not issue expressions of interest or an RFP for the Initial LCE projects. Opportunities for initial LCE Projects were solicited broadly through BC Hydro's Key Account Managers and Community Relations Managers, and through our existing commercial and industrial energy manager networks. This approach allowed us to build an understanding of the level of customer

knowledge and interest in LCE.

2.55.1 Please list the steps taken by BC Hydro to select these Initial LCE projects.

RESPONSE:

Please refer to BC Hydro's response to ZONE II IR 1.27.1 which explains the criteria that BC Hydro used for the initial LCE projects.

Once a project is submitted to BC Hydro, the following steps occur:

- **Customers submit some key information that includes current energy consumption, current peak demand, incremental electricity consumption from project, estimated GHG reduction and a high level estimate of project cost. The information is then assessed by BC Hydro staff. Considerations include: is the project technically feasible, is the customer in a constrained supply location, does the project reduce GHG emissions, does the project provide a positive NPV, and timing of project completion;**
- **A more detailed engineering study may be requested to provide more information on the project, its benefits and costs. Results from the study provide revised information that is reviewed by BC Hydro; and**
- **Should the project pass the above review steps, discussions are held with the customer, potentially leading to a funding agreement.**

55.0 Topic: Low Carbon Electrification Program

Reference: Exhibit B-6, Zone II RPG IR 1.27.1.1

In its response to Zone II RPG IR 1.27.1.1, BC Hydro confirmed that:

BC Hydro did not issue expressions of interest or an RFP for the Initial LCE projects. Opportunities for initial LCE Projects were solicited broadly through BC Hydro's Key Account Managers and Community Relations Managers, and through our existing commercial and industrial energy manager networks. This approach allowed us to build an understanding of the level of customer knowledge and interest in LCE.

2.55.1 Please list the steps taken by BC Hydro to select these Initial LCE projects.

2.55.1.1 Provide the criteria that was used to select the initial LCE projects.

RESPONSE:

Please refer to BC Hydro's response to ZONE II RPG IR 1.27.1 where we outline the criteria used to select the initial LCE projects.

55.0 Topic: Low Carbon Electrification Program

Reference: Exhibit B-6, Zone II RPG IR 1.27.1.1

In its response to Zone II RPG IR 1.27.1.1, BC Hydro confirmed that:

BC Hydro did not issue expressions of interest or an RFP for the Initial LCE projects. Opportunities for initial LCE Projects were solicited broadly through BC Hydro's Key Account Managers and Community Relations Managers, and through our existing commercial and industrial energy manager networks. This approach allowed us to build an understanding of the level of customer knowledge and interest in LCE.

2.55.2 Provide the BC Hydro financial guidelines policy or other that provided BC Hydro the authority to not issue an RFP.

RESPONSE:

This answer also responds to ZONE II RPG IRs 2.55.2.1 and 2.55.2.2.

There is no BC Hydro policy that requires BC Hydro to issue a RFP for incentives in DSM or LCE programs.

The current process for LCE is consistent with our DSM process which has been in practice for a number of years. The process recognises that customers often work with BC Hydro to assist in the identification and development of potential projects. Our experience is that customers appreciate being able to submit proposed projects on their timeframe, in accordance with their budgeting process, rather than waiting for an arbitrary BC Hydro-initiated call date. In addition, the process provides customers with timely decisions as to whether the project will receive an incentive, which allows those customers to make budget decisions.

55.0 Topic: Low Carbon Electrification Program

Reference: Exhibit B-6, Zone II RPG IR 1.27.1.1

In its response to Zone II RPG IR 1.27.1.1, BC Hydro confirmed that:

BC Hydro did not issue expressions of interest or an RFP for the Initial LCE projects. Opportunities for initial LCE Projects were solicited broadly through BC Hydro's Key Account Managers and Community Relations Managers, and through our existing commercial and industrial energy manager networks. This approach allowed us to build an understanding of the level of customer knowledge and interest in LCE.

2.55.2 Provide the BC Hydro financial guidelines policy or other that provided BC Hydro the authority to not issue an RFP.

2.55.2.1 Did the process BC Hydro use to choose these LCE proponents vary from BC Hydro's policy?

RESPONSE:

Please refer to BC Hydro's response to ZONE II RPG IR 2.55.2.

55.0 Topic: Low Carbon Electrification Program

Reference: Exhibit B-6, Zone II RPG IR 1.27.1.1

In its response to Zone II RPG IR 1.27.1.1, BC Hydro confirmed that:

BC Hydro did not issue expressions of interest or an RFP for the Initial LCE projects. Opportunities for initial LCE Projects were solicited broadly through BC Hydro's Key Account Managers and Community Relations Managers, and through our existing commercial and industrial energy manager networks. This approach allowed us to build an understanding of the level of customer knowledge and interest in LCE.

2.55.2 Provide the BC Hydro financial guidelines policy or other that provided BC Hydro the authority to not issue an RFP.

2.55.2.2 If so, please explain.

RESPONSE:

Please refer to BC Hydro's response to ZONE II RPG IR 2.55.2.

55.0 Topic: Low Carbon Electrification Program

Reference: Exhibit B-6, Zone II RPG IR 1.27.1.1

In its response to Zone II RPG IR 1.27.1.1, BC Hydro confirmed that:

BC Hydro did not issue expressions of interest or an RFP for the Initial LCE projects. Opportunities for initial LCE Projects were solicited broadly through BC Hydro's Key Account Managers and Community Relations Managers, and through our existing commercial and industrial energy manager networks. This approach allowed us to build an understanding of the level of customer knowledge and interest in LCE.

2.55.3 Explain how BC Hydro provided transparency to other proponents/projects that may have submitted proposals to have their projects reviewed.

RESPONSE:

BC Hydro prepares an annual report which outlines our low carbon electrification activities and expenditures (GGRR Annual Report). The report is provided to the BCUC and the fiscal 2018 report is provided as Appendix BB of the Application.

BC Hydro also has an ongoing dialogue with customers who submit proposals. We provide feedback to the customer regarding BC Hydro's program criteria as well as reasons why BC Hydro may have determined that their project was not eligible for an incentive.

BC Hydro does not discuss details of a customer's project with other customers because the information could be considered commercially sensitive.